COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE ADJUSTMENT
OF ELECTRIC RATES OF DUKE ENERGY KENTUCKY, INC.

CASE NO. 2017-00321

FILING REQUIREMENTS

VOLUME 16

Duke Energy Kentucky, Inc.
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Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	6	807 KAR 5:001 Section 14(2)	If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.	James P. Henning
1	7	807 KAR 5:001 Section 14(3)	If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.	James P. Henning
1	8	807 KAR 5:001 Section 14(4)	If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.	James P. Henning
1	9	807 KAR 5:001 Section 16 (1)(b)(1)	Reason adjustment is required.	James P. Henning William Don Wathen, Jr.
1	10	807 KAR 5:001 Section 16 (1)(b)(2)	Certified copy of certificate of assumed name required by KRS 365.015 or statement that certificate not necessary.	James P. Henning
1	11	807 KAR 5:001 Section 16 (1)(b)(3)	New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed	Bruce L. Sailers
1	12	807 KAR 5:001 Section 16 (1)(b)(4)	Proposed tariff changes shown by present and proposed tariffs in comparative form or by indicating additions in italics or by underscoring and striking over deletions in current tariff.	Bruce L. Sailers
1	13	807 KAR 5:001 Section 16 (1)(b)(5)	A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.	James P. Henning
1	14	807 KAR 5:001 Section 16(2)	If gross annual revenues exceed $5,000,000, written notice of intent filed at least 30 days, but not more than 60 days prior to application. Notice shall state whether application will be supported by historical or fully forecasted test period.	James P. Henning
1	15	807 KAR 5:001 Section 16(3)	Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.	James P. Henning

1	16	807 KAR 5:001 Section 16(6)(a)	The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.	Robert H. Pratt
1	17	807 KAR 5:001 Section 16(6)(b)	Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.	Sarah E. Lawler Cynthia S. Lee Robert H. Pratt
1	18	807 KAR 5:001 Section 16(6)(c)	Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.	Sarah E. Lawler
1	19	807 KAR 5:001 Section 16(6)(d)	After an application based on a forecasted test period is filed, there shall be no revisions to the forecast, except for the correction of mathematical errors, unless the revisions reflect statutory or regulatory enactments that could not, with reasonable diligence, have been included in the forecast on the date it was filed. There shall be no revisions filed within thirty (30) days of a scheduled hearing on the rate application.	Robert H. Pratt
1	20	807 KAR 5:001 Section 16(6)(e)	The commission may require the utility to prepare an alternative forecast based on a reasonable number of changes in the variables, assumptions, and other factors used as the basis for the utility's forecast.	Robert H. Pratt
1	21	807 KAR 5:001 Section 16(6)(f)	The utility shall provide a reconciliation of the rate base and capital used to determine its revenue requirements.	Sarah E. Lawler
1	22	807 KAR 5:001 Section 16(7)(a)	Prepared testimony of each witness supporting its application including testimony from chief officer in charge of Kentucky operations on the existing programs to achieve improvements in efficiency and productivity, including an explanation of the purpose of the program.	All Witnesses
1	23	807 KAR 5:001 Section 16(7)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Robert H. Pratt Joseph A. Miller Anthony J. Platz
1	24	807 KAR 5:001 Section 16(7)(c)	Complete description, which may be in prefiled testimony form, of all factors used to prepare forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.	Robert H. Pratt
1	25	807 KAR 5:001 Section 16(7)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Robert H. Pratt
1	26	807 KAR 5:001 Section 16(7)(e)	Attestation signed by utility's chief officer in charge of Kentucky operations providing: 1. That forecast is reasonable, reliable, made in good faith and that all basic assumptions used have been identified and justified; and 2. That forecast contains same assumptions and methodologies used in forecast prepared for use by management, or an identification and explanation for any differences; and 3. That productivity and efficiency gains are included in the forecast.	James P. Henning

1	27	807 KAR 5:001 Section 16(7)(f)	For each major construction project constituting 5% or more of annual construction budget within 3 year forecast, following information shall be filed: 1. Date project began or estimated starting date; 2. Estimated completion date; 3. Total estimated cost of construction by year exclusive and inclusive of Allowance for Funds Used During construction ("AFUDC") or Interest During construction Credit; and 4. Most recent available total costs incurred exclusive and inclusive of AFUDC or Interest During Construction Credit.	Robert H. Pratt Joseph A. Miller Anthony J. Platz
1	28	807 KAR 5:001 Section 16(7)(g)	For all construction projects constituting less than 5% of annual construction budget within 3 year forecast, file aggregate of information requested in paragraph (f) 3 and 4 of this subsection.	Robert H. Pratt Joseph A. Miller Anthony J. Platz
1	29	807 KAR 5:001 Section 16(7)(h)	Financial forecast for each of 3 forecasted years included in capital construction budget supported by underlying assumptions made in projecting results of operations and including the following information: 1. Operating income statement (exclusive of dividends per share or earnings per share); 2. Balance sheet; 3. Statement of cash flows; 4. Revenue requirements necessary to support the forecasted rate of return; 5. Load forecast including energy and demand (electric); 6. Access line forecast (telephone); 7. Mix of generation (electric); 8. Mix of gas supply (gas); 9. Employee level; 10.Labor cost changes; 11.Capital structure requirements; 12.Rate base; 13.Gallons of water projected to be sold (water); 14.Customer forecast (gas, water); 15.MCF sales forecasts (gas); 16.Toll and access forecast of number of calls and number of minutes (telephone); and 17.A detailed explanation of any other information provided.	Robert H. Pratt John Verderame John L. Sullivan, III Benjamin Passty
1	30	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	David L. Doss
2	31	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	John L. Sullivan, III
2	32	807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone).	David L. Doss
3-4	33	807 KAR 5:001 Section 16(7)(l)	Annual report to shareholders or members and statistical supplements for the most recent 2 years prior to application filing date.	John L. Sullivan, III
5	34	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	David L. Doss
5	35	807 KAR 5:001 Section 16(7)(n)	Latest 12 months of the monthly managerial reports providing financial results of operations in comparison to forecast.	David L. Doss

5	36	807 KAR 5:001 Section 16(7)(o)	Complete monthly budget variance reports, with narrative explanations, for the 12 months prior to base period, each month of base period, and subsequent months, as available.	David L. Doss Robert H. Pratt
6-8	37	807 KAR 5:001 Section 16(7)(p)	SEC's annual report for most recent 2 years, Form 10-Ks and any Form 8-Ks issued during prior 2 years and any Form 10-Qs issued during past 6 quarters.	David L. Doss
9	38	807 KAR 5:001 Section 16(7)(q)	Independent auditor's annual opinion report, with any written communication which indicates the existence of a material weakness in internal controls.	David L. Doss
9	39	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	John L. Sullivan
9	40	807 KAR 5:001 Section 16(7)(s)	Summary of latest depreciation study with schedules itemized by major plant accounts, except that telecommunications utilities adopting PSC's average depreciation rates shall identify current and base period depreciation rates used by major plant accounts. If information has been filed in another PSC case, refer to that case's number and style.	John J. Spanos
9	41	807 KAR 5:001 Section 16(7)(t)	List all commercial or in-house computer software, programs, and models used to develop schedules and work papers associated with application. Include each software, program, or model; its use; identify the supplier of each; briefly describe software, program, or model; specifications for computer hardware and operating system required to run program	Sarah E. Lawler
9	42	807 KAR 5:001 Section 16(7)(u)	If utility had any amounts charged or allocated to it by affiliate or general or home office or paid any monies to affiliate or general or home office during the base period or during previous 3 calendar years, file: 1. Detailed description of method of calculation and amounts allocated or charged to utility by affiliate or general or home office for each allocation or payment; 2. method and amounts allocated during base period and method and estimated amounts to be allocated during forecasted test period; 3. Explain how allocator for both base and forecasted test period was determined; and 4. All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated or paid during base period is reasonable.	Jeffrey R. Setser
10	43	807 KAR 5:001 Section 16(7)(v)	If gas, electric or water utility with annual gross revenues greater than $5,000,000, cost of service study based on methodology generally accepted in industry and based on current and reliable data from single time period.	James E. Ziolkowski

11	44	807 KAR 5:001 Section 16(7)(w)	Local exchange carriers with fewer than 50,000 access lines need not file cost of service studies, except as specifically directed by PSC. Local exchange carriers with more than 50,000 access lines shall file: 1. Jurisdictional separations study consistent with Part 36 of the FCC's rules and regulations; and 2. Service specific cost studies supporting pricing of services generating annual revenue greater than $1,000,000 except local exchange access: a. Based on current and reliable data from single time period; and b. Using generally recognized fully allocated, embedded, or incremental cost principles.	N/A
11	45	807 KAR 5:001 Section 16(8)(a)	Jurisdictional financial summary for both base and forecasted periods detailing how utility derived amount of requested revenue increase.	Sarah E. Lawler
11	46	807 KAR 5:001 Section 16(8)(b)	Jurisdictional rate base summary for both base and forecasted periods with supporting schedules which include detailed analyses of each component of the rate base.	Sarah E. Lawler Cynthia S. Lee Robert H. Pratt Lisa M. Belluci James E. Ziolkowski David L. Doss
11	47	807 KAR 5:001 Section 16(8)(c)	Jurisdictional operating income summary for both base and forecasted periods with supporting schedules which provide breakdowns by major account group and by individual account.	Sarah E. Lawler
11	48	807 KAR 5:001 Section 16(8)(d)	Summary of jurisdictional adjustments to operating income by major account with supporting schedules for individual adjustments and jurisdictional factors.	Sarah E. Lawler Cynthia S. Lee Robert H. Pratt James E. Ziolkowski
11	49	807 KAR 5:001 Section 16(8)(e)	Jurisdictional federal and state income tax summary for both base and forecasted periods with all supporting schedules of the various components of jurisdictional income taxes.	Lisa M. Bellucci
11	50	807 KAR 5:001 Section 16(8)(f)	Summary schedules for both base and forecasted periods (utility may also provide summary segregating items it proposes to recover in rates) of organization membership dues; initiation fees; expenditures for country club; charitable contributions; marketing, sales, and advertising; professional services; civic and political activities; employee parties and outings; employee gifts; and rate cases.	Sarah E. Lawler
11	51	807 KAR 5:001 Section 16(8)(g)	Analyses of payroll costs including schedules for wages and salaries, employee benefits, payroll taxes, straight time and overtime hours, and executive compensation by title.	Sarah E. Lawler Tom Silinski
11	52	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Sarah E. Lawler
11	53	807 KAR 5:001 Section 16(8)(i)	Comparative income statements (exclusive of dividends per share or earnings per share), revenue statistics and sales statistics for 5 calendar years prior to application filing date, base period, forecasted period, and 2 calendar years beyond forecast period.	David L. Doss Robert H. Pratt

11	54	807 KAR 5:001 Section 16(8)(j)	Cost of capital summary for both base and forecasted periods with supporting schedules providing details on each component of the capital structure.	John L. Sullivan, III
11	55	807 KAR 5:001 Section 16(8)(k)	Comparative financial data and earnings measures for the 10 most recent calendar years, base period, and forecast period.	Cynthia S. Lee Robert H. Pratt John L. Sullivan David L. Doss
11	56	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
11	57	807 KAR 5:001 Section 16(8)(m)	Revenue summary for both base and forecasted periods with supporting schedules which provide detailed billing analyses for all customer classes.	Bruce L. Sailers
11	58	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
11	59	807 KAR 5:001 Section 16(10)	Request for waivers from the requirements of this section shall include the specific reasons for the request. The commission shall grant the request upon good cause shown by the utility.	Legal
11	60	807 KAR 5:001 Section (17)(1)	(1) Public postings. (a) A utility shall post at its place of business a copy of the notice no later than the date the application is submitted to the commission. (b) A utility that maintains a Web site shall, within five (5) business days of the date the application is submitted to the commission, post on its Web sites: 1. A copy of the public notice; and 2. A hyperlink to the location on the commission's Web site where the case documents are available. (c) The information required in paragraphs (a) and (b) of this subsection shall not be removed until the commission issues a final decision on the application.	James P. Henning

11	61	807 KAR 5:001 Section 17(2)	(2) Customer Notice. (a) If a utility has twenty (20) or fewer customers, the utility shall mail a written notice to each customer no later than the date on which the application is submitted to the commission. (b) If a utility has more than twenty (20) customers, it shall provide notice by: 1. Including notice with customer bills mailed no later than the date the application is submitted to the commission; 2. Mailing a written notice to each customer no later than the date the application is submitted to the commission; 3. Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made no later than the date the application is submitted to the commission; or 4. Publishing notice in a trade publication or newsletter delivered to all customers no later than the date the application is submitted to the commission. (c) A utility that provides service in more than one (1) county may use a combination of the notice methods listed in paragraph (b) of this subsection.	James P. Henning
11	62	807 KAR 5:001 Section 17(3)	(3) Proof of Notice. A utility shall file with the commission no later than forty-five (45) days from the date the application was initially submitted to the commission: (a) If notice is mailed to its customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, that notice was mailed to all customers, and the date of the mailing; (b) If notice is published in a newspaper of general circulation in the utility's service area, an affidavit from the publisher verifying the contents of the notice, that the notice was published, and the dates of the notice's publication; or (c) If notice is published in a trade publication or newsletter delivered to all customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, the mailing of the trade publication or newsletter, that notice was included in the publication or newsletter, and the date of mailing.	James P. Henning

11	63	807 KAR 5:001 Section 17(4)	(4) Notice Content. Each notice issued in accordance with this section shall contain: (a) The proposed effective date and the date the proposed rates are expected to be filed with the commission; (b) The present rates and proposed rates for each customer classification to which the proposed rates will apply; (c) The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply; (d) The amount of the average usage and the effect upon the average bill for each customer classification to which the proposed rates will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer classification for the proposed rate change in basic local service; (e) A statement that a person may examine this application at the offices of (utility name) located at (utility address); (f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov; (g) A statement that comments regarding the application may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602; (h) A statement that the rates contained in this notice are the rates proposed by (utility name) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice; (i) A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and (j) A statement that if the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.	Bruce L. Sailers
11	64	807 KAR 5:001 Section 17(5)	(5) Abbreviated form of notice. Upon written request, the commission may grant a utility permission to use an abbreviated form of published notice of the proposed rates, provided the notice includes a coupon that may be used to obtain all the required information.	N/A
12	-	807 KAR 5:001 Section 16(8)(a) through (k)	Schedule Book (Schedules A-K)	Various
13	-	807 KAR 5:001 Section 16(8)(l) through (n)	Schedule Book (Schedules L-N)	Bruce L. Sailers

14	-	-	Work papers	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 6)	Various
16	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 6)	Various
17	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 6)	Various
18	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 4 of 6)	Various
19	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 5 of 6)	Various
20	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 6 of 6)	Various
20	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

Direct Testimony of
Roger A. Morin, PhD

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)))))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

ROGER A. MORIN, PhD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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APPENDICES

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 Kentucky, Inc. (Duke Energy Kentucky 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 Kentucky Public Service Commission (the Commission) and the Federal Energy Regulatory Commission. I have testified before the following state, provincial, and other local regulatory commissions:

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

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 Kentucky's electric utility operations in the State Kentucky. 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 Kentucky to attract the capital needed for infrastructure and reliability investments on reasonable terms;

(3) maintain Duke Energy Kentucky'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 KENTUCKY'S COST OF COMMON EQUITY.

A. It is my opinion that a fair, reasonable and sufficient ROE for Duke Energy Kentucky falls in the upper half of a range between 9.0% and 10.7%, that is, 9.9% - 10.7%. This range is based on the Commission's adoption of Duke Energy Kentucky'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 9.9% - 10.7% in order to account for Duke Energy Kentucky's high external financing risks relative to its size, it's very small size, a substantial increase in interest rates predicted over the next several years, a highly concentrated generation mix, and a higher degree of regulatory risk.

A ROE in the range of 9.9% - 10.7% for Duke Energy Kentucky 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 9.9% - 10.7% FOR DUKE ENERGY KENTUCKY'S ELECTRIC UTILITY OPERATIONS?

A. Yes. My analysis shows that this range fairly compensates investors, maintains Duke Energy Kentucky'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 Kentucky has access to capital markets for its capital needs, a fair and reasonable authorized ROE in the range of 9.9% - 10.7% is required.

Duke Energy Kentucky 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 Kentucky'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 Kentucky 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 Kentucky's financial integrity; and

(iii) sufficient to maintain Duke Energy Kentucky'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 Kentucky 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 KENTUCKY'S COST OF COMMON EQUITY?

A. Two fundamental economic principles underlie the appraisal of Duke Energy Kentucky'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 KENTUCKY OBTAIN ITS CAPITAL AND HOW IS ITS OVERALL COST OF CAPITAL DETERMINED?

A. The funds employed by Duke Energy Kentucky 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. <u>COST OF EQUITY CAPITAL ESTIMATES</u>

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

A. To estimate a fair ROE for Duke Energy Kentucky, 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 Kentucky.

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 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, declining customer usage, the uncertain impact of distributed generation, 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 8 of my 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 KENTUCKY'S COST OF EQUITY WITH THE DCF MODEL?

A. In estimating Duke Energy Kentucky'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 KENTUCKY'S COST OF EQUITY WITH THE DCF METHOD?

A. Because Duke Energy Kentucky is not publicly traded, the DCF model cannot be applied to Duke Energy Kentucky 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 Kentucky. 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 Kentucky. 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 Kentucky, 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 uncertain capital market and industry environment, 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 KENTUCKY'S UTILITY BUSINESS?

A. As proxies for Duke Energy Kentucky, 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 Kentucky's. I began with all the companies designated as combination gas and electric utilities by AUS Utility Reports that

[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.

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. Fortis was also added to the group since it owns several US combination gas and electric 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. The first 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 second excluded company as Entergy Corp. on account of its ongoing corporate restructuring. The third company was MDU Resources because revenues from regulated electric utility operations were less than 50%. The fourth excluded company was Pepco Holdings which has been merged with Exelon. The fifth excluded company was Unitil because of its very small size and because it is not covered in the Value Line data base. The sixth excluded company was TECO Energy which has been acquired by Emera.

The final group of twenty-three companies that comprise the Duke Energy Kentucky proxy group is shown on Attachment RAM-3. I stress that this proxy

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

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 KENTUCKY USING VALUE LINE GROWTH PROJECTIONS?

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

As shown on column 3, line 25 of Attachment RAM-4, the average long-term earnings per share growth forecast obtained from Value Line is 5.93% for Duke Energy Kentucky's proxy group. Combining this growth rate with the average expected dividend yield of 3.33% shown on column 4, line 25 of Attachment RAM-4 produces an estimate of equity costs of 9.27% for Duke Energy Kentucky's proxy group, as shown on column 5, line 25 of Attachment RAM-4. Recognition of flotation costs brings the cost of equity estimate to 9.44% 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 KENTUCKY USING ANALYSTS' CONSENSUS GROWTH FORECASTS?

A. Attachment RAM-5 displays the DCF analysis using analysts' consensus growth forecasts for the twenty-three companies in Duke Energy Kentucky's proxy group. Please note that the growth forecasts for Avista Corp. and MGE Energy were drawn from the Yahoo Finance web site since the Zacks growth forecast were not available for these two companies. The Fortis growth forecast was taken from Value Line.

As shown on column 3, line 25 of Attachment RAM-5, the average long-term earnings per share growth forecast obtained from analysts is 5.53% for Duke Energy Kentucky's proxy group. Combining this growth rate with the average expected dividend yield of 3.33% shown on column 4, line 25, produces an estimate of equity costs of 8.86% for Duke Energy Kentucky's proxy group unadjusted for flotation cost, as shown on column 5, line 25, of Attachment RAM-5. Recognition of flotation costs brings the cost of equity estimate to 9.03%, shown in Column 6, line 25.

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

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

Table 1. DCF Estimates for Duke Energy Kentucky

DCF STUDY	ROE
Electric Utilities Value Line Growth	9.44%
Electric Utilities Analysts Growth	9.03%

B. CAPM Estimates

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, the U.S. Energy Information Administration, and the U.S. Bureau of Labor Statistics among others 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].

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.

[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

	US 30-Yr Treas. L/T Yield Forecast
Congressional Budget Office	4.1
Bureau of Labor Statistics	4.8
U.S. Energy Information Administration	4.3
IHS (Global Insight)	4.6
Value Line Economic Forecast	4.7
Economic Report of the President	4.2
AVERAGE	**4.4**

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 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 Kentucky 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 Kentucky. Based on these results, I shall use 0.70, as an estimate for the beta applicable to Duke Energy Kentucky.

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%[5], 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 1926-2015 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.

[5] 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%.

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 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.[6]

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.

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[6] *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. 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%).

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.

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%

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[7] 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 KENTUCKY'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?

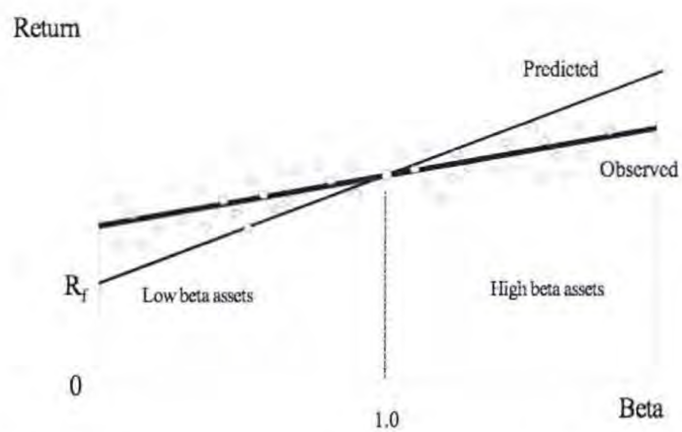
A. There have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, The New

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

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.[8] Thus, it is reasonable to apply a conservative alpha adjustment.

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

[8] 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:

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

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 Standard and Poor's Utility Index (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.

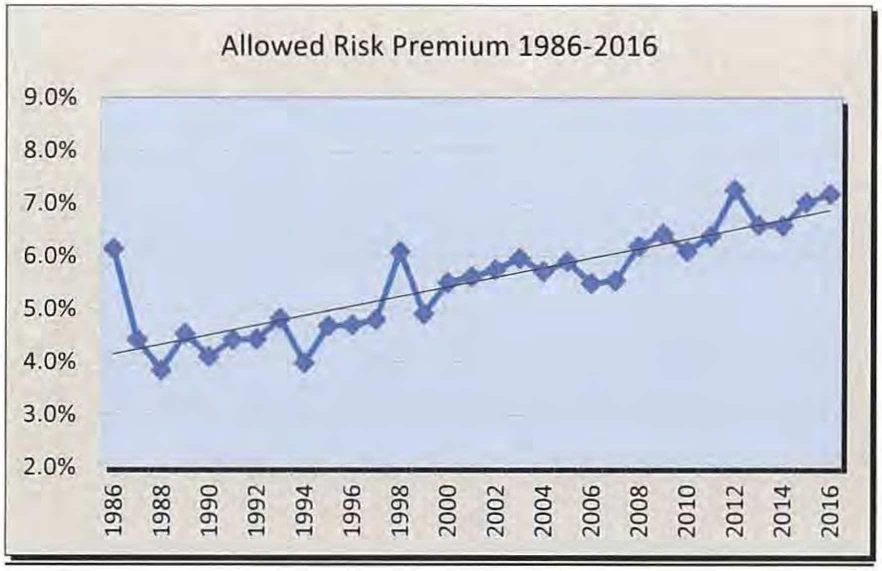
D. Allowed Risk Premium Estimates

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 1986-2016 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 5.5% over the entire 1986-2016 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.

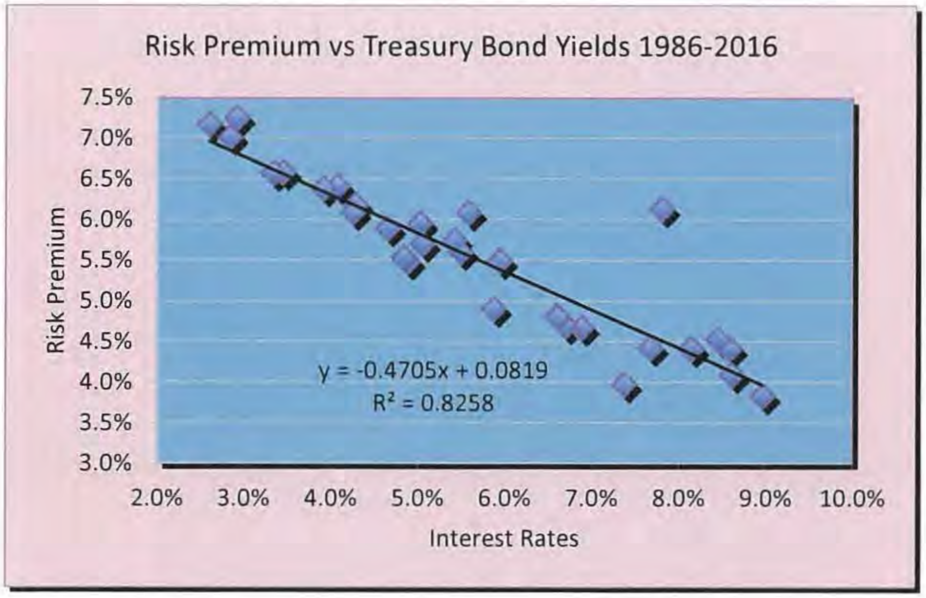


A careful review of these ROE decisions relative to interest rate trends reveals a narrowing of the risk premium in times of rising interest rates, and a widening of the premium as interest rates fall. The following statistical relationship between the risk premium (RP) and interest rates (YIELD) emerges over the 1986-2016 period:

$$RP = 8.1900 - 0.4705\ YIELD \qquad R^2 = 0.83$$

The relationship is highly statistically significant[9] 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.

[9] 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 6.1%, implying a cost of equity of 10.5%. The latter result is very close 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

Risk Premium Method	ROE
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

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 continues 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 KENTUCKY 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. IMPACT OF RIDERS

Q. DR. MORIN, IS YOUR ROE RECOMMENDATION IMPACTED BY THE COMPANY'S REQUESTED FERC TRANSMISSION COST RECONCILIATION (FTR), ENVIRONMENTAL COMPLIANCE (ESM), DISTRIBUTION CAPITAL (DCI) AND PROFIT SHARING MECHAMISM (PSM) RIDERS?

A. No, it is not.

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

A. The presence of a 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 riders on the Company's business risks because my recommended market-derived ROE for Duke Energy Kentucky 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 Kentucky. 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 2015 study by the Edison Foundation ("*Alternative Regulation for Emerging Utility Challenges: 2015 Update*") reports that a majority of states either have decoupling/revenue adjustment mechanisms in place, or are reviewing or implementing them. The study also reports on the prevalence of direct cost recovery mechanisms in most of the fifty states.

The major point of all this is that while risk-mitigating mechanisms such as the FTR, DCI, ESM, and PSM riders reduce 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 Kentucky'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, generation concentration, 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 comprehensive study by the Brattle Group[10] 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.

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

Q. DR. MORIN, CAN YOU PLEASE COMMENT ON THE COMMISSION'S PRACTICE TO RELY ON AVERAGE ROEs CURRENTLY ALLOWED BY OTHER REGULATORS.

A. Yes, I can. My first reaction is that it is circular to set a fair return based on the past actions of other regulators, much like observing a series of duplicate images in multiple mirrors. The rates of return earned by other regulated utilities may very well have been reasonable under historical conditions, but they are still subject to tests of reasonableness under current and prospective conditions.

My second reaction is that the average allowed return in a given time period is just that, an average. There are very large deviations both above and below the average allowed return presumably due to risk differences between utilities. For example, in 2016 there were 42 ROE decisions reported in RRA's annual compilation of regulatory awards averaging 9.77%. The authorized ROEs varied from 8.6% to 11.6%, with 18 of the 42 decisions higher than the average of 9.77%. The same is true for the first quarter of 2017 where the average allowed ROE was 9.9%. The ROEs varied from 9.0% to 11.4%, with 6 of the 14 decisions in excess of the average. The major point of all this is that regulators do and should take Company-specific risk into account when authorizing ROEs as attested by the variability in the allowed ROE data, and I strongly believe that the Commission should follow suit and exercise a mind of its own when authorizing ROEs.

V. 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 Kentucky.

Table 6. Summary of ROE Estimates

STUDY	ROE
Combination Utilities Value Line Growth	9.4%
Combination Utilities Analysts Growth	9.0%
CAPM	9.5%
Empirical CAPM	10.0%
Historical Risk Premium Electric	10.7%
Allowed Risk Premium	10.5%

The average estimate is 9.9% and the truncated mean[11] is also 9.9%. The results range from 9.0% to 10.7%, with a midpoint of 9.9%. Based on all those results, I use the upper half of the range, 9.9% - 10.7% as my recommended ROE range for Duke Energy Kentucky.

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.

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

A. For three reasons. First, the Company is projected to raise very large sums of money in a rising interest rate environment over the next five years relative to its small size. High business risks result from a 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 $710 million of financing over the next five years for new utility infrastructure

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

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 (ownership capital) is approximately $1,051 million. In other words, the company is expected to spend an amount which represents more than one half of its entire common equity ownership capital.

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 THE SECOND REASON WHY YOU RECOMMEND THAT THE ROE BE SET IN THE UPPER HALF PORTION OF YOUR ESTIMATED RANGE?

A. The second reason is the Company's very small size. Duke Energy Kentucky is one of the smallest electric utilities in the industry on the basis of revenues, capital base, and number of customers. The Company's very small size must also be considered in arriving at the cost of common equity. Duke Energy Kentucky possesses very small revenue and asset bases, both in absolute terms and relative to the other electric utilities in the comparable group. Investment risk increases as company size diminishes, all else remaining constant. The size phenomenon is well documented in the finance literature, and is fully discussed in Chapter 6 of my book The New Regulatory Finance and is also fully discussed in the Duff & Phelps Valuation 2016 Yearbook which devotes two full chapters and two appendices documenting and quantifying the size effect. The gist of the literature is that small companies have very different returns than large ones and on average those returns have been higher. The greater risk of small stocks does not fully account for their higher returns over many historical periods. The average small stock premium is well in excess of that of the average stock, more than could be expected by risk differences alone, suggesting that the cost of equity for small stocks is considerably larger than for large capitalization stocks. In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

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

A. The third reason is the risk related to the Company's generation concentration and lack of resource diversity. The Company generation requirements are met with only one single coal-fired generating station which supplies all base load requirements, with little to no reserve capacity. A costly combustion turbine accommodates peak load requirements, but at very high costs.

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

A. Based on the results of all my analyses, the application of my professional judgment, and the risk circumstances of Duke Energy Kentucky, it is my opinion that a just and reasonable ROE for Duke Energy Kentucky's electric utility operations in the State Kentucky lies in a range of 9.9% - 10.7% range.

Q. WERE EXHIBITS RAM-1 THROUGH RAM-8 AND APPENDICES A AND B PREPARED BY YOU AND UNDER YOUR DIRECTIONAND CONTROL?

A. Yes, they were.

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

A. Yes.

VERIFICATION

PROVINCE OF NOVA SCOTIA)
) **SS:**
COUNTY OF HALIFAX)

The undersigned, Dr. Roger A. Morin, Professor of Finance and a Principal in Utility Research International, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Roger A Morin

Dr. Roger A. Morin Affiant

Subscribed and sworn to before me by Dr. Roger A. Morin on this 27TH day of JULY, 2017.

Kelly Matt

NOTARY PUBLIC

Kelly Mattinson
A Commissioner of the
Supreme Court of Nova Scotia

My Commission Expires: September 14/17

RESUME OF ROGER A. MORIN

(Winter 2017)

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EMPLOYER 1980-2015: Georgia State University
Robinson College of Business
Atlanta, GA 30303

RANK: Emeritus Professor of Finance

HONORS: Distinguished Professor of Finance for Regulated Industry,
Director Center for the Study of Regulated Industry,
Robinson College of Business, Georgia State University.

EDUCATIONAL HISTORY

- Bachelor of Electrical Engineering, McGill University, Montreal, Canada, 1967.
- Master of Business Administration, McGill University, Montreal, Canada, 1969.
- PhD in Finance & Econometrics, Wharton School of Finance, University of Pennsylvania, 1976.

EMPLOYMENT HISTORY

- Lecturer, Wharton School of Finance, Univ. of Pennsylvania, 1972-3
- Assistant Professor, University of Montreal School of Business, 1973-1976.
- 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

OTHER BUSINESS ASSOCIATIONS

- 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
Cincinnatti 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

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Metropolitan Edison, Pennsylvania PUC, Docket #R-822249
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Northern Telephone, Ontario PSC
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Edmonton Power Company, Alberta Public Service Board
Kansas Power & Light, F.E.R.C., Docket # ER 83-418

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Bell South, FCC generic cost of capital Docket #84-800
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Mountain Bell, Colorado PUB
South Central Bell, Louisiana PS
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Vermont Gas Systems, Vermont PSC
Alberta Power Ltd., Alberta PUB
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Georgia Power Company, Georgia PSC
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Centra Gas (Manitoba) Co.
Central Telephone Co. Nevada
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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
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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
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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, l978.

"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. l982, 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.

Investment-Grade Dividend-Paying Combination Gas and Electric Utilities Covered in Value Line's Electric Utility Industry

	Company	Ticker		Note
1	Alliant Energy	LNT		
2	Ameren Corp.	AEE		
3	Avista Corp.	AVA		
4	Black Hills	BKH		Acquired SourceGas, completed 2/2016
5	CenterPoint Energy	CNP		
6	Chesapeake Utilities	CPK		
7	CMS Energy Corp.	CMS		
8	Consol. Edison	ED		
9	Dominion Resources	D		Merged with Questar, completed 9/16
10	DTE Energy	DTE		
11	Duke Energy	DUK		Acquired Piedmont Natual Gas, completed 10/16
12	Empire Dist. Elec.	EDE	x	Merged with Liberty Util. subsidiary, completed 1/17
13	Entergy Corp	ETR	x	Nuclear exposure
14	Eversource Energy	ES		
15	Fortis	FTS		Owns several US combination gas & elec utilities
16	Exelon Corp	EXC		
17	MDU Resource	MDU	x	Reg. Revenues < 50%
18	MGE Energy	MGEE		
19	NorthWestern Corp.	NWE		
20	Pepco Holdings	POM	x	Merged with Exelon
21	PG&E Corp.	PCG		
22	Public Serv. Enterprise	PEG		
23	SCANA Corp.	SCG		
24	Unitil Corp	UTL	x	Market cap < $1B; not covered by VL
25	Sempra Energy	SRE		
26	TECO Energy	TE	x	Acquired by Emera
27	Vectren Corp.	VVC		
28	WEC Energy Group	WEC		
29	Xcel Energy Inc.	XEL		

Source: AUS Utility Reports 2016, Value Line Investment Survey 06/17

Proxy Group for Duke Energy Kentucl

	Company	Ticker
1	Alliant Energy	LNT
2	Ameren Corp.	AEE
3	Avista Corp.	AVA
4	Black Hills	BKH
5	CenterPoint Energy	CNP
6	Chesapeake Utilities	CPK
7	CMS Energy Corp.	CMS
8	Consol. Edison	ED
9	Dominion Resources	D
10	DTE Energy	DTE
11	Duke Energy	DUK
12	Eversource Energy	ES
13	Exelon Corp	EXC
14	Fortis	FTS
15	MGE Energy	MGEE
16	NorthWestern Corp.	NWE
17	PG&E Corp.	PCG
18	Public Serv. Enterprise	PEG
19	SCANA Corp.	SCG
20	Sempra Energy	SRE
21	Vectren Corp.	VVC
22	WEC Energy Group	WEC
23	Xcel Energy Inc.	XEL

Combination Elec & Gas Utilities
DCF Analysis Value Line Growth Rates

Line No.	(1) Company Name	(2) Current Dividend Yield	(3) Projected EPS Growth	(4) % Expected Divid Yield	(5) Cost of Equity	(6) ROE
1	Alliant Energy	3.04	6.0	3.22	9.22	9.39
2	Ameren Corp.	3.10	6.0	3.29	9.29	9.46
3	Avista Corp.	3.34	2.5	3.42	5.92	6.10
4	Black Hills	2.56	7.5	2.75	10.25	10.40
5	CenterPoint Energy	3.74	6.0	3.96	9.96	10.17
6	Chesapeake Utilities	1.80	8.0	1.94	9.94	10.05
7	CMS Energy Corp.	2.81	6.5	2.99	9.49	9.65
8	Consol. Edison	3.33	2.5	3.41	5.91	6.09
9	Dominion Resources	3.74	5.5	3.95	9.45	9.65
10	DTE Energy	3.01	5.0	3.16	8.16	8.33
11	Duke Energy	3.99	5.5	4.21	9.71	9.93
12	Eversource Energy	3.06	6.5	3.26	9.76	9.93
13	Exelon Corp	3.61	7.0	3.86	10.86	11.07
14	Fortis	3.90	9.0	4.25	13.25	13.47
15	MGE Energy	1.89	7.0	2.02	9.02	9.13
16	NorthWestern Corp.	3.39	4.5	3.54	8.04	8.23
17	PG&E Corp.	2.87	9.5	3.14	12.64	12.81
18	Public Serv. Enterprise	3.83	2.5	3.93	6.43	6.63
19	SCANA Corp.	3.59	4.0	3.73	7.73	7.93
20	Sempra Energy	2.82	8.0	3.05	11.05	11.21
21	Vectren Corp.	2.74	7.0	2.93	9.93	10.09
22	WEC Energy Group	3.31	6.0	3.51	9.51	9.69
23	Xcel Energy Inc.	3.01	4.5	3.15	7.65	7.81
25	**AVERAGE**	**3.15**	**5.93**	**3.33**	**9.27**	**9.44**

Notes:

28 Column 1, 2, 3: Value Line Research Web Site Jun 2017

29 Column 4 = Column 2 times (1 + Column 3/100)

30 Column 5 = Column 4 + Column 3

31 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	3.04	5.5	3.21	8.71	8.88
2	Ameren Corp.	3.10	6.5	3.30	9.80	9.98
3	Avista Corp.	3.34	6.7	3.56	10.26	10.45
4	Black Hills	2.56	5.0	2.69	7.69	7.83
5	CenterPoint Energy	3.74	5.0	3.93	8.93	9.13
6	Chesapeake Utilities	1.80	6.0	1.91	7.91	8.01
7	CMS Energy Corp.	2.81	6.0	2.98	8.98	9.14
8	Consol. Edison	3.33	3.6	3.45	7.05	7.23
9	Dominion Resources	3.74	6.0	3.96	9.96	10.17
10	DTE Energy	3.01	5.9	3.19	9.09	9.26
11	Duke Energy	3.99	5.0	4.19	9.19	9.41
12	Eversource Energy	3.06	6.3	3.25	9.55	9.72
13	Exelon Corp	3.61	4.9	3.79	8.69	8.89
14	Fortis	3.90	9.0	4.25	13.25	13.47
15	MGE Energy	1.89	4.0	1.97	5.97	6.07
16	NorthWestern Corp.	3.39	3.3	3.50	6.80	6.99
17	PG&E Corp.	2.87	4.4	3.00	7.40	7.55
18	Public Serv. Enterprise	3.83	3.0	3.94	6.94	7.15
19	SCANA Corp.	3.59	5.3	3.78	9.08	9.28
20	Sempra Energy	2.82	8.7	3.07	11.77	11.93
21	Vectren Corp.	2.74	5.7	2.90	8.60	8.75
22	WEC Energy Group	3.31	6.0	3.51	9.51	9.69
23	Xcel Energy Inc.	3.01	5.4	3.17	8.57	8.74
25	**AVERAGE**	**3.15**	**5.53**	**3.33**	**8.86**	**9.03**

Notes:

28 Column 1, 2: Value Line Research Web Site Jun 2017

29 Column 3: Zacks Investment Research growth forecast Jun 2017

30 Column 4 = Column 2 times (1 + Column 3/100)

31 Column 5 = Column 4 + Column 3

32 Column 6 = Column 4/0.95 + Column 3

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	Black Hills	0.90
5	CenterPoint Energy	0.90
6	Chesapeake Utilities	0.70
7	CMS Energy Corp.	0.70
8	Consol. Edison	0.50
9	Dominion Resources	0.70
10	DTE Energy	0.70
11	Duke Energy	0.60
12	Eversource Energy	0.70
13	Exelon Corp	0.70
14	Fortis	0.70
15	MGE Energy	0.80
16	NorthWestern Corp.	0.70
17	PG&E Corp.	0.70
18	Public Serv. Enterprise	0.70
19	SCANA Corp.	0.70
20	Sempra Energy	0.80
21	Vectren Corp.	0.70
22	WEC Energy Group	0.60
23	Xcel Energy Inc.	0.60
25	**AVERAGE**	**0.70**

27 Source: Value Line Research Jun 2017

Utility Industry Historical Risk Premium

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

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%

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%**

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 2016 Classic Yearbook (Morningstar) Table A-9 Long-Term Government Bonds Yields

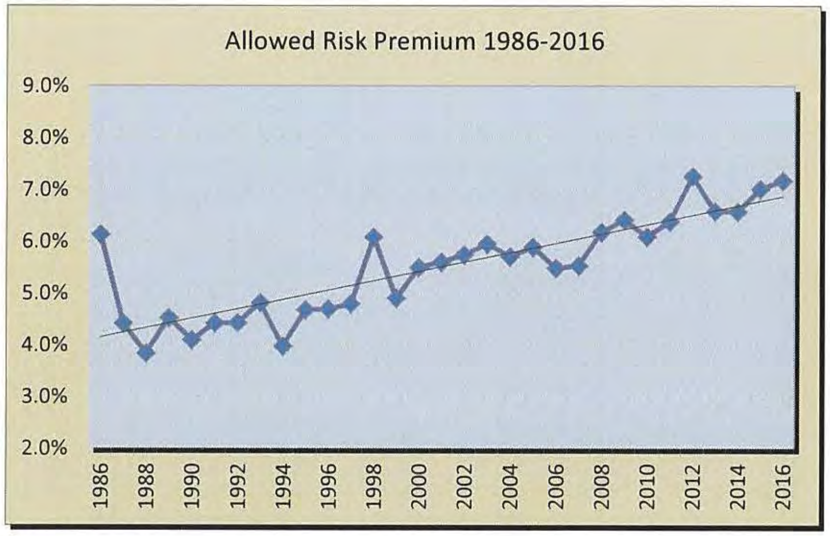
ALLOWED RISK PREMIUM 1986-2016

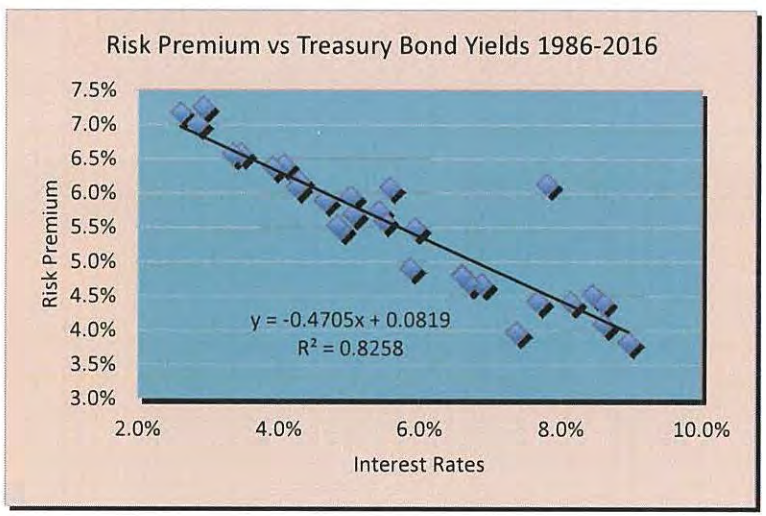
Line	Date	Treasury Bond Yield[1]	Authorized Electric Returns[2]	Indicated Risk Premium
		(1)	(2)	(3)
1	1986	7.80%	13.93%	6.1%
2	1987	8.58%	12.99%	4.4%
3	1988	8.96%	12.79%	3.8%
4	1989	8.45%	12.97%	4.5%
5	1990	8.61%	12.70%	4.1%
6	1991	8.14%	12.55%	4.4%
7	1992	7.67%	12.09%	4.4%
8	1993	6.60%	11.41%	4.8%
9	1994	7.37%	11.34%	4.0%
10	1995	6.88%	11.55%	4.7%
11	1996	6.70%	11.39%	4.7%
12	1997	6.61%	11.40%	4.8%
13	1998	5.58%	11.66%	6.1%
14	1999	5.87%	10.77%	4.9%
15	2000	5.94%	11.43%	5.5%
16	2001	5.49%	11.09%	5.6%
17	2002	5.42%	11.16%	5.7%
18	2003	5.02%	10.97%	6.0%
19	2004	5.05%	10.75%	5.7%
20	2005	4.65%	10.54%	5.9%
21	2006	4.88%	10.36%	5.5%
22	2007	4.83%	10.36%	5.5%
23	2008	4.28%	10.46%	6.2%
24	2009	4.07%	10.48%	6.4%
25	2010	4.25%	10.34%	6.1%
26	2011	3.91%	10.29%	6.4%
27	2012	2.92%	10.17%	7.3%
28	2013	3.45%	10.03%	6.6%
29	2014	3.34%	9.91%	6.6%
30	2015	2.84%	9.85%	7.0%
31	2016	2.60%	9.77%	7.2%
32	**Average**	**5.70%**	**11.21%**	**5.5%**

Sources:

[1] Fed Reserve Brd of Governors H.15 Release

[2] SNL (Regulatory Research Associates)
Major Rate Case Decisions 1986-2016





IF YIELD =	4.40%
THEN RP =	6.12%
Ke =	10.52%

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:

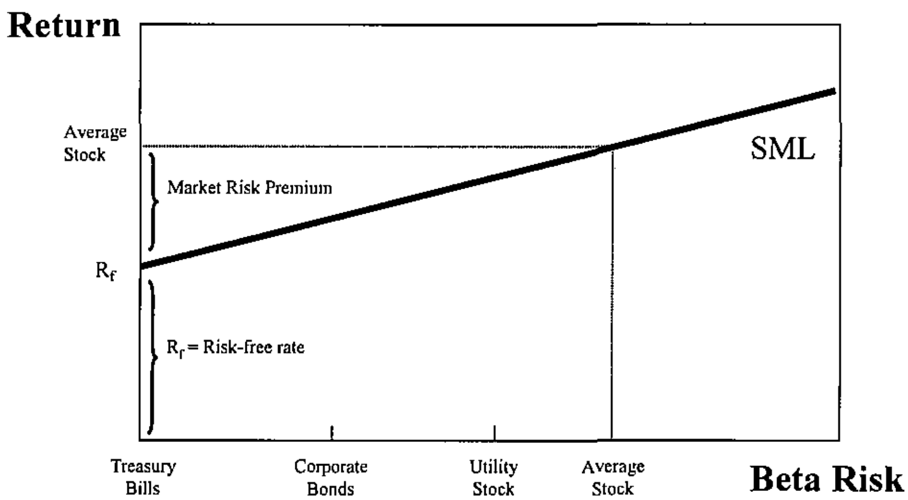
$$K = R_F + \beta(R_M - R_F) \qquad (1)$$

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.

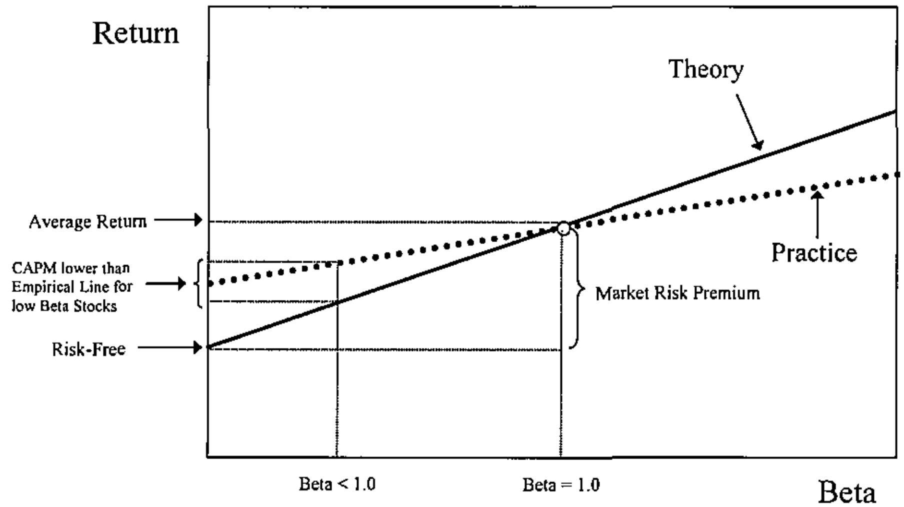
CAPM and Risk - Return
in Capital Markets



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:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \tag{3}$$

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:

$$K = R_F + a\,MRP + (1-a)\,\beta\,MRP \tag{4}$$

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.

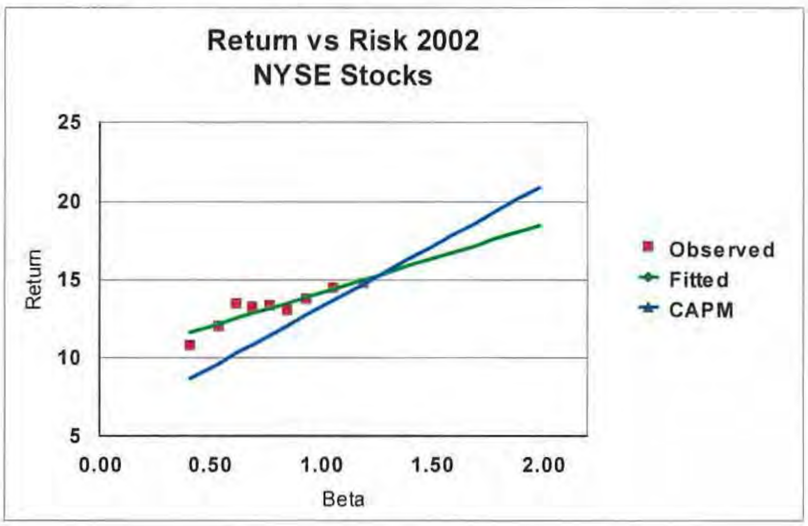
Most of the empirical studies cited in the above table utilize raw betas rather than Value Line adjusted betas because the latter were not available over most of the time periods covered in these studies. A study of the relationship between return and adjusted beta is reported on Table 6-7 in Ibbotson 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

[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.

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).

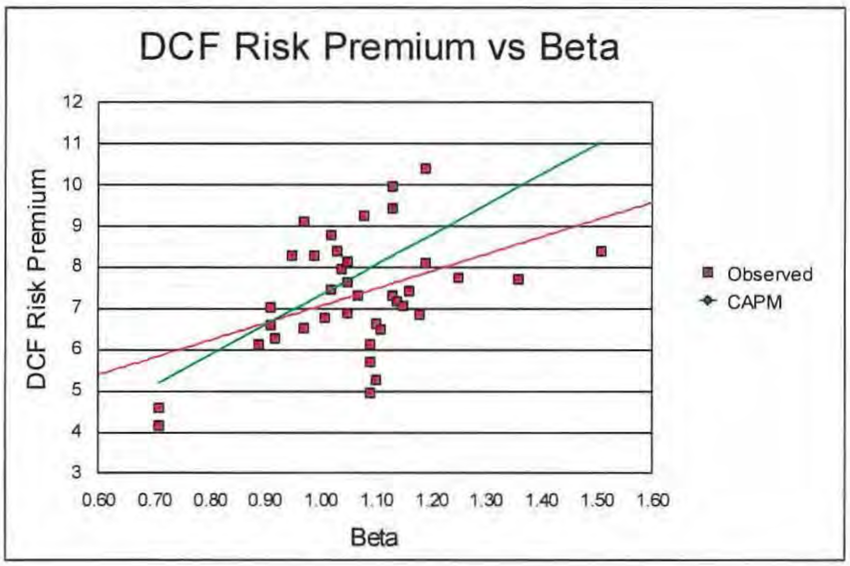
The table below, drawn from HMMO Table 4, displays the average estimate prospective risk premium (Column 2) by industry and the corresponding beta estimate for that industry, both in raw form (Column 3) and adjusted form (Column 4). The latter were calculated with the traditional Value Line – Merrill 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
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:

$$K = R_F + \alpha + \beta\ (MRP - \alpha) \tag{5}$$

or, alternatively by the following equivalent relationship:

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

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:

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

[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

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]:

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

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].

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[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

[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:

$$K = D_1/P_0 + g$$

If P_0 is regarded as the proceeds per share actually received by the company from which dividends and earnings will be generated, that is, P_0 equals B_0, the book value per share, then the company's required return is:

$$r = D_1/B_0 + g$$

Denoting the percentage flotation costs 'f', proceeds per share B_0 are related to market price P_0 as follows:

$$P - fP = B_0$$

$$P(1 - f) = B_0$$

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 = (D/P + g)	**14.00%**
ALLOWED RETURN ON EQUITY = (D/P(1-f) + g)	**14.47%**

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%**	

Direct Testimony of
Benjamin Walter Bohdan
Passty, PhD

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-00321

DIRECT TESTIMONY OF

BENJAMIN WALTER BOHDAN PASSTY, PH.D.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Benjamin Walter Bohdan Passty. 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 a Lead Load Forecasting Analyst in the Load Forecasting group. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics and a Bachelor of Science Degree in Mathematics from Trinity University in 2002, a Master of Arts degree in Economics from Northwestern University in 2003, and a Doctor of Philosophy in Economics from Northwestern University in 2008.

I joined Duke Energy Corp. in July 2013 as a Lead Forecaster in the Load Forecasting Department. My current title is Lead Load Forecasting Analyst.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. I currently serve on the board of the Charlotte Economics Club, a local chapter of the National Association For Business Economists.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS SENIOR FORECASTER IN THE LOAD FORECASTING GROUP.

A. My primary responsibility is to develop Duke Energy's long-term electric forecasts for portions of its Midwest service area, currently Kentucky, Ohio and Indiana. These forecasts and analyses are provided to departments throughout Duke Energy and are used for budgeting, generation planning, and regulatory filings, such as long-term forecast reports, integrated resource plans, and rate cases. In addition to my primary duties, I regularly support special projects, requiring statistical analysis and forecasting, including assessment of current economic conditions.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY BEFORE ANY OTHER REGULATORY AGENCIES?

A. Yes. I have presented testimony on several occasions before the Indiana Utility Regulatory Commission.

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

A. My testimony presents and explains Duke Energy Kentucky's long-term energy and demand forecast prepared in 2017 and utilized in the Company's rate case filing. This includes a discussion of the level of normal weather utilized in the preparation of the forecast. In addition, I describe how Duke Energy Kentucky's current portfolio of regulated demand side management (DSM), energy efficiency (EE) and load management programs –which help Duke Energy Kentucky meet its energy and peak demand requirements—are factored into the load forecast. Because of some differences in terminology, I will refer to these programs collectively as Utility Energy Efficiency (UEE) Programs throughout my testimony. I sponsor Filing Requirement (FR) 16(7)(h)(5). I also discuss certain information that I supplied to Duke Energy Kentucky witness Mr. Robert "Beau" Pratt for his use in preparing the forecasted financial data.

II. <u>LOAD FORECAST</u>

Q. DID YOU PREPARE THE COMPANY'S LOAD FORECAST?

A. Yes, I did.

Q. HOW IS DUKE ENERGY KENTUCKY'S LOAD FORECAST DEVELOPED?

A. Generally speaking, the Load Forecast is developed in three steps: first, a service area economic forecast is obtained; next, an energy forecast is prepared; and finally, using the energy forecast, summer and winter peak demand forecasts are developed.

The forecast methodology is essentially the same as that presented in past Integrated Resource Plans filed with the Kentucky Public Service Commission (Commission). The only difference would be that the models have been updated to include more recent data.

Q. PLEASE DESCRIBE HOW THE SERVICE AREA ECONOMIC FORECAST IS OBTAINED.

A. The economic forecast for Northern Kentucky and the Greater Cincinnati region is obtained from Moody Analytics' portal *Economy.com* (Moody's), a nationally recognized economic forecasting firm. Based upon its forecast of the national economy, Moody's prepares a forecast of key economic concepts specific to the greater Cincinnati area, including the portion of Northern Kentucky served by Duke Energy Kentucky. This forecast provides detailed projections of employment, income, wages, industrial production, inflation, prices, and population. This information serves as input into the energy forecast models.

The Duke Energy Kentucky service area is located in Northern Kentucky adjacent to the city of Cincinnati which is contained within the service area of Duke Energy Ohio, another subsidiary of Duke Energy. The economy of Northern Kentucky is contained within the Cincinnati Primary Metropolitan Statistical Area (PMSA) and is an integral part of the regional economy.

Q. HOW IS THE ENERGY FORECAST DEVELOPED?

A. The energy forecast projects the load required to serve Duke Energy Kentucky's retail customer classes - residential, commercial, industrial, government or other public authority (OPA), and street lighting. The projected energy requirements for Duke Energy Kentucky's retail electric customers are determined through econometric analysis. Econometric models are a means of representing economic behavior through the use of statistical methods, such as regression analysis.

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING ENERGY USAGE?

A. Some of the major factors are the number of residential customers, weather, and economic activity measures such as employment, industrial production, income and price. For the residential sector, the key factors are the population of the area, real median per capita income, real energy prices, weather, appliance saturations, and appliance efficiencies. For the commercial sector, the key factors include the weather, employment and income, and real energy prices. The appliance data on saturation and efficiencies are incorporated into the Residential Usage and Commercial models through the use of an additive term commonly referred to as a "statistically adjusted end-use" term (SAE term). The SAE term allows for these data to be interacted with the key factors named above. In the industrial sector, the key factors include industrial production, real energy prices, and the weather. The governmental sector model includes the specific portion of economic output that Moody's classifies as government gross domestic product (Government GDP), as well as energy prices and weather. Finally, for the street lighting sector, the key factor is the number of residential customers.

Generally, energy use increases with higher industrial and commercial activity along with the increased saturation of residential appliances, including space heating and cooling equipment. As energy prices increase, energy usage tends to decrease due to customers' conservation activities.

Q. ARE THESE FACTORS RECOGNIZED IN THE EQUATIONS USED TO PROJECT THE ENERGY REQUIREMENTS OF DUKE ENERGY KENTUCKY'S RETAIL CUSTOMERS?

A. Yes, they are. By exposing the forecasting models to these variables, we can project future energy consumption conditional on forecasts of these economic and weather conditions.

Q. HOW IS THE FORECAST OF ENERGY REQUIREMENTS FOR DUKE ENERGY KENTUCKY'S RETAIL CUSTOMERS PREPARED?

A. While many economic and weather variables are relevant to the entire greater Cincinnati area, the Duke Energy Kentucky sales forecast is developed by maintaining specific forecasting models for sales only to Duke Energy Kentucky customers in the residential, commercial, industrial, government or OPA, and street lighting sectors. Forecasts are also prepared for three minor categories: interdepartmental use, Company use, and line losses associated with transmission and distribution. Rather than there being separate customer class models, the peak forecast model—discussed in greater detail down below—is estimated on a total retail basis.

Q. ARE THERE ANY ADJUSTMENTS MADE TO THE ALLOCATED FORECASTS DERIVED FROM THE ECONOMETRIC MODELS?

A. The output of the model estimation is adjusted for the impacts of projected growth in behind-the-meter solar generation, electric vehicle usage, and the impacts of new energy efficiency programs. The Company may adjust the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site. However, for the 2017 Load Forecast there were no adjustments for new customer loads or expansion at a current customer's site.

Q. PLEASE EXPLAIN HOW THE PEAK FORECASTS ARE DEVELOPED.

A. The Company projects both a winter and a summer peak for the total region using econometric equations that forecast peak demand as a function of economic growth, as measured by energy sales, end-use data, and several key weather factors. The Duke Energy Kentucky peak load forecast is estimated separately from any other system peak. The model is exposed to monthly peak data, with normalized weather conditions for the day of peak based on thirty-year' data. The attachment BWP-3 shows the monthly peak weather normal degree days used to compute peaks for Duke Energy Kentucky.

Q. DOES DUKE ENERGY KENTUCKY'S ENERGY AND PEAK LOAD FORECAST ALREADY INCLUDE THE IMPACT OF HISTORICAL UEE PROGRAMS?

A. Yes, the impact of the historical UEE programs that have been implemented in the Duke Energy Kentucky service area are already reflected in these forecasts. The data used to develop the 2017 Load Forecast incorporate the historical impact of those existing programs prior to model estimation. The model output is then readjusted downwards for those, as well as future UEE program projections.

Q. DOES DUKE ENERGY KENTUCKY'S LOAD FORECAST USED IN THIS CASE INCLUDE CONSIDERATION OF THE IMPACT FROM THE INSTALLATION OF COST-EFFECTIVE ENERGY UEE PROGRAMS?

A. Yes. It is my understanding that, according to the Commission's Administrative Case 2009-00498, utilities must explain consideration of cost-effective energy efficiency resources and the impacts of such resources on the utility test year. For Duke Energy Kentucky, incremental peak load reductions due to current and future UEE programs are used to adjust the historical data as part of the process of calculating the 2017 Load Forecast. The projected incremental impact of existing programs through the next two fiscal years (July 1, 2017 through June 2019) is an additional reduction of almost 37 million kWh total, and 2 MW at time of peak. The load forecast provided here does reflect those projected energy efficiency impacts.

Q. ARE THERE ANY OTHER PEAK LOAD REDUCTIONS THAT ARE NOT INCLUDED IN DUKE ENERGY KENTUCKY'S LOAD FORECAST?

A. Yes. The load forecast has not been reduced for the impact of load reductions due to the Company's special contract interruptible customers, or for load reductions attributable to the Real-Time Pricing (RTP) program. While there is no explicit adjustment for these programs, I believe that their results are embedded within the historical data on peak that are used for the model estimation, so not accounting for them separately is appropriate.

Q. IS DUKE ENERGY KENTUCKY'S LOAD FORECASTING METHODOLOGY SIMILAR TO THAT EMPLOYED AT THE TIME OF THE COMPANY'S LAST BASE ELECTRIC RATE CASE?

A. Yes, the econometric forecasting methodology used to create the Load Forecast is basically the same as that used by the Company in prior cases. Two differences that are worthy of mention are the inclusion of a SAE-term, as I discuss above, and the rolling thirty-year weather normalization period, which I will discuss below.

Q. ARE YOU FAMILIAR WITH OTHER ELECTRIC UTILITIES' LONG-TERM LOAD FORECASTS?

A. Yes, I am.

Q. ARE THE FACTORS THAT ARE USED BY DUKE ENERGY KENTUCKY IN FORMULATING ITS LOAD FORECASTS SIMILAR TO THE FACTORS USED BY OTHER UTILITIES IN THEIR LOAD FORECASTS?

A. Yes. While other utilities might use a variety of load forecasting approaches, such as econometric, end-use, trend analysis, or time series analysis, nearly all of the utilities I am familiar with use the same factors considered by Duke Energy Kentucky, to varying degrees. These commonly used factors include: population, weather data, income forecasts, industrial production measures, employment, and price information. In addition, price forecasts for alternate fuels including natural gas and fuel oil are used as well. I am aware of survey data indicating that many large utilities utilize an approach consistent with the SAE methodology.

Q. HOW DOES MANAGEMENT JUDGMENT FIT INTO THE LOAD FORECASTS?

A. Under any approach to load forecasting, judgment is an essential element. Each utility must use the approach that, in its judgment, best suits its particular situation, taking into account the various factors.

Q. PLEASE DESCRIBE ATTACHMENT BWP-1.

A. Attachment BWP-1 is a summary of Duke Energy Kentucky's energy and peak load forecast. The projected annualized rate of growth in total retail sales for the five-year period 2017 to 2022 is 0.04% and for the ten-year period 2017 to 2027 is 0.3% per year. The projected rate of growth in weather-normalized peak demand is negligible between 2017 and 2022.

III. DEGREE DAY DATA USED IN THE FORECAST

Q. HOW IS WEATHER MEASURED FOR PURPOSES OF THE ELECTRIC FORECAST?

A. Weather is expressed in terms of Heating Degree Days and Cooling Degree Days.

Q. WHAT IS A HEATING DEGREE DAY AND A COOLING DEGREE DAY?

A. A Heating Degree Day (HDD) is calculated using a base temperature measured on the Fahrenheit scale and occurs when the daily average temperature is below the base. HDD measures the difference of the daily average temperature and the base temperature. The formula is:

$$\text{Heating Degree Days} = \text{Base Temperature} - \text{Daily Average Temperature}$$

A Cooling Degree Day (CDD) is also calculated using a base temperature measured on the Fahrenheit scale. However, it occurs when the daily average temperature is above the base. CDD measure the difference of the daily average temperature and the base temperature. The formula is:

Cooling Degree Days = Daily Average Temperature – Base Temperature

Any negative result of these calculations is taken to be zero.

Q. PLEASE EXPLAIN "NORMAL" WEATHER.

A. The electric forecast projects Duke Energy Kentucky's electric sales for the test period. In order to project this, one must make a judgment about the weather conditions expected to occur during the test period. This is known as "normal" weather. The electric forecast is based on such expected weather conditions, which are forecast from historical weather data. Because an electric forecast is forward-looking and intended to predict what is likely to happen in the future, an assumption must be made as to what impact weather is likely to have on the future electric forecast. There is no "actual" weather available for a future period, so a proxy must be used. A reasonable, accepted and industry standard methodology to factor the impact of weather is to use an average of prior actual weather to predict what future weather patterns are likely to be experienced.

Q. PLEASE DESCRIBE HOW DUKE ENERGY KENTUCKY CALCULATED NORMAL WEATHER?

A. Duke Energy Kentucky uses a rolling 30-year period to calculate the Normal Weather in its electric forecast.

Q. DOES THE NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION (NOAA) PROVIDE NORMAL WEATHER DATA FOR DUKE ENERGY KENTUCKY'S SERVICE AREA?

A. Yes. NOAA is responsible for monitoring climate conditions in the United States. Additional information about NOAA is available at their web site at www.noaa.gov. The standard time period prescribed by the United Nations World Meteorological Organization for measuring climate conditions is 30 years, and NOAA updates its calculations for the United States for these 30-year periods at the end of each decade. The most current 30-year period used by NOAA is 1981-2010. NOAA's next 30-year normal weather period will be released several years from now and will encompass the period spanning 1991-2020.

Because of its infrequent updates, the Duke Energy Kentucky's forecast does not use the NOAA calculations. Rather, the Company uses more contemporaneous weather data in performing its forecasts, rolling in the latest year available at the time of the forecast.

Q. WHAT YEARS ARE USED TO CALCULATE THE ROLLING 30-YEAR WEATHER NORMAL FOR THE MOST RECENT DUKE ENERGY KENTUCKY ELECTRIC FORECAST?

A. The years 1986-2015 were used to calculate normal weather. As a new year of weather data—subject to a delay—becomes available, it is our practice to roll off the oldest year and replace it.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY?

A. With respect to cooling, the years 1986-2015 appear to hint at a slight upward trend. Basic econometric analysis fails to confirm that this trend is caused by anything other than random variation. The slight decreasing trend in heating degree days over the same period—while visually hinted at—also fails to hold up under statistical testing. The graph in attachment BWP-5 shows these charts.

Q. WHAT HAS BEEN THE TREND IN HDD AND CDD FOR COVINGTON, KENTUCKY, OVER THE LAST TEN YEARS?

A. Because 2007 was a particularly warm year, the last ten years suggest a slight cooling of summer weather; once again, statistical work cannot distinguish any trend from random variation. The data on winter heating degree days show a small decline upon visual inspection.

Q. HOW DO THE ACTUAL ANNUAL HDD AND CDD FOR THE LAST TEN YEARS FOR COVINGTON, KENTUCKY, COMPARE TO 30-YEAR NORMALS?

A. See Attachment BWP-5 for a graph comparing the annual degree days in heating/cooling to the forecasts of the 30-year normal scheme, as well as the ten-year normal scheme and the NOAA normal. The ten-year normal calls for slightly more extreme weather than the thirty-year normal. Annual weather is much more variable than the degree to which the various forecasts vary from each other. Regarding cooling, the rolling 30-year normal prediction is closer than the 10-

year prediction in three out of the four most recent years. This is also the case in two out of four recent years for heating degree days.

Q. DID YOU MEASURE HOW RELIABLE THE VARIOUS WEATHER NORMALS ARE?

A. Yes. One way to compare the relationship between the expected normal level of degree days to the actual number of degree days is to use a statistic known as the Mean Percent Error (MPE). MPE indicates whether the measure of normal degree days contains any bias to over-estimate or under-estimate the actual weather conditions. If MPE is positive, this indicates that there is a bias for the measure of normal to be higher than the actual. The formula to calculate MPE is the sum of (Normal Degree Days minus Actual Degree Days) divided by Actual Degree Days. The sum is then divided by the number of observations. Mathematically:

$$\mathrm{MPE} = \frac{1}{\mathrm{N}} \sum_{t=1}^{N} \frac{\hat{Y}_t - Y_t}{Y_t}$$

Where $\hat{Y}$ = Normal Annual Degree Days

and Y = Actual Annual Degree Days

A difficulty with using this sum to compare the options for weather normalization is data availability: because so many years are required to compute the thirty-year weather normal, this statistic basically compares normal over a narrow sample space, implying a large standard error relative to any measurement difference. Because standard errors shrink for larger samples, the standard error of a 30-year forecast for normal weather should have a confidence interval that is 40 percent as large as the confidence interval around 10-year estimates. Because so many years are required for calculating the 30-year normal, it's really only possible to compare accuracy for years beginning with 2011 (which implies many too few years for statistical testing). An informal comparison of the two forecasts for degree days shows slightly greater mean square error for the weather in years beginning with 2011 when using the 30-year normal instead of the 10-year normal, but with so few data points, it's impossible to reject the statistical hypothesis that the expected error is equal.

IV. DUKE ENERGY KENTUCKY'S UEE/LOAD MANAGEMENT PROGRAMS

Q. WHAT HAS BEEN THE IMPACT OF THE COMPANY'S UEE PROGRAMS ON THE LOAD FORECAST?

A. Through 2016, the Company's UEE programs are estimated to have reached an annual savings level of over 154,000 MWh and reduced the summer peak load by 16 MW.

Q. PLEASE BRIEFLY DESCRIBE DUKE ENERGY KENTUCKY'S CURRENT PORTFOLIO OF UEE AND LOAD CONTROL PROGRAMS.

A. Duke Energy Kentucky offers its customers multiple regulated UEE (EE and DSM) related services and products, as well as low income assistance programs within the Commonwealth of Kentucky. The various UEE are vetted through one of two collaborative processes (residential and industrial) before being submitted to the Commission for review and approval. Duke Energy Kentucky recovers its costs and receives compensation for these services pursuant to its Commission-approved DSM tariff riders. The current suite of programs include the following:

- Residential Smart $aver®;
- Residential Energy Assessments;

- Energy Efficiency Education Program for Schools;
- Low Income Services;
- The Payment Plus program;
- Residential Direct Load Control- Power Manager;
- My Home Energy Report;
- Low Income Neighborhood Program;
- Gas Weatherization;
- Smart $aver® Prescriptive;
- Smart $aver® Custom;
- Smart $aver® Energy Assessments;.
- Small Business Energy Saver;
- PowerShare®; and
- PilotLite;

The Commission has approved each of these programs and reviews the costs and results of these programs on an annual basis.

Q. PLEASE BRIEFLY DESCRIBE HOW THE POWERSHARE QUOTEOPTION LOAD REDUCTIONS ARE REPRESENTED IN DUKE ENERGY KENTUCKY'S IRP.

A. This is an elective program without contractual commitment, meant to be used as a hedge against the effects of extreme weather. For this reason, the QuoteOption load reduction is currently not represented in Duke Energy Kentucky's IRP.

Q. DOES DUKE ENERGY KENTUCKY OFFER ANY OTHER PROGRAMS THAT PROVIDE LOAD CONTROL OPPORTUNITIES TO CUSTOMERS?

A. Yes. The Company also offers a Real-Time Pricing opportunity for non-residential customers that allow them the opportunity to manage their load in response to market signals.

Q. PLEASE DESCRIBE THE REAL TIME PRICING (RTP) PROGRAM.

A. Duke Energy Kentucky's RTP program (Rate RTP – Experimental Real Time Pricing Program) consists of a two-part rate: an access charge for the customer's historic load that is billed at standard tariff rates (commonly referred to as the "CBL"); and an energy charge for the customer's incremental or decremental energy usage that is billed at a real time price. Once customers receive information on the next day hourly prices, they can adjust their energy usage to either increase loads during low price times and/or decrease usage during high priced times.

Q. WHAT IS THE LOAD IMPACT OF DUKE ENERGY KENTUCKY'S LOAD MANAGEMENT PROGRAMS?

A. Currently, the Duke Energy Kentucky customer accounts that participate in RTP provide an expected peak load reduction of 1-2 MWs. Historically, the load impact from the RTP program has been projected to be 2 MW, although 1 MW is probably closer to the reduction at time of peak for recent summers. Lately we have had some mild summers, which limit the number of high-price periods in the data. The Duke Energy Kentucky RTP customers haven't been very price responsive. Impacts from any other programs can be treated as embedded in the load forecast, as they fall within the margin of error of our models.

Q. WAS THE LOAD FORECAST MODIFIED TO ACCOUNT FOR FUTURE IMPACTS OF ALL OF THESE DSM/UEE PROGRAMS?

A. Yes it was. The raw forecast produced by the econometric models was modified by taking UEE program forecasts and subtracting them. In addition, the cumulative impact of these programs was mitigated by a roll-off schedule that accounts for the fact that codes and standards organically evolve in ways that would naturally reduce energy usage over time.

V. FILING REQUIREMENTS AND INFORMATION SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(7)(h)(5).

A. FR 16(7)(h)(5) consists of the load forecast, which I described earlier in my testimony.

Q. DID YOU SUPPLY ANY INFORMATION TO OTHER WITNESSES IN THIS PROCEEDING?

A. Yes, I supplied Mr. Pratt with the gas Mcf and electric kWh sales for the forecasted portion of the base period, consisting of the twelve months ending November 30, 2017, and the forecasted test period, consisting of the twelve months ending March 31, 2019.

Q. DO YOU BELIEVE THE ELECTRIC FORECAST IS A REASONABLE AND ACCURATE DEPICTION OF THE COMPANY'S ANTICIPATED FUTURE ELECTRIC LOAD?

A. Yes.

VI. CONCLUSION

Q. WERE FR 16(7)(h)(5), THE INFORMATION YOU PROVIDED TO MR. PRATT AND ATTACHMENTS BWP-1 THROUGH BWP-5 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Benjamin Walter Bohdan Passty., Lead Load Forecasting Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Benjamin Walter Bohdan Passty

Benjamin Walter Bohdan Passty Affiant

Subscribed and sworn to before me by Benjamin Walter Bohdan Passty on this 27 day of July, 2017.

Patricia C. Ross

NOTARY PUBLIC

My Commission Expires: 10-17-2019

PATRICIA C. ROSS
NOTARY PUBLIC
Mecklenburg County
North Carolina

DUKE ENERGY KENTUCKY
SERVICE AREA ENERGY FORECAST (MEGAWATT HOURS) (a)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET-HWY LIGHTING	OPA	OTHER	(1+2+3+4+5+6) TOTAL CONSUMPTION
-5	2012	1,460,789	1,444,273	779,644	15,006	297,176	855	3,997,744
-4	2013	1,457,588	1,440,598	803,623	15,362	289,351	873	4,007,395
-3	2014	1,480,911	1,460,552	827,629	15,274	289,992	954	4,075,313
-2	2015	1,433,316	1,478,984	813,519	15,120	291,546	804	4,033,289
-1	2016	1,472,994	1,500,730	815,042	15,264	294,412	757	4,099,199
0	2017	1,452,266	1,482,752	815,925	15,397	289,613	716	4,056,669
1	2018	1,465,693	1,489,720	820,174	15,436	286,072	716	4,077,811
2	2019	1,477,779	1,495,511	816,918	15,458	281,099	716	4,087,481
3	2020	1,477,387	1,498,209	810,672	15,479	278,801	718	4,081,266
4	2021	1,477,125	1,486,723	807,415	15,498	276,453	716	4,063,929
5	2022	1,488,081	1,481,930	804,130	15,516	275,121	716	4,065,494
6	2023	1,505,842	1,485,618	808,898	15,534	274,146	716	4,090,754
7	2024	1,529,949	1,497,048	811,741	15,550	273,595	718	4,128,601
8	2025	1,540,195	1,497,126	812,221	15,565	272,031	716	4,137,855
9	2026	1,555,294	1,502,750	809,552	15,579	270,362	716	4,154,252
10	2027	1,571,565	1,510,598	810,113	15,592	268,960	716	4,177,544
11	2028	1,591,275	1,522,858	815,925	15,604	266,083	718	4,212,463
12	2029	1,601,963	1,523,718	817,767	15,616	260,336	716	4,220,114
13	2030	1,615,451	1,519,004	814,848	15,626	253,993	716	4,219,636
14	2031	1,631,032	1,516,254	811,633	15,635	247,105	716	4,222,374
15	2032	1,657,426	1,524,096	808,893	15,643	243,598	718	4,250,374
16	2033	1,676,185	1,525,149	810,683	15,650	239,963	716	4,268,346
17	2034	1,702,972	1,533,587	814,365	15,657	237,636	716	4,304,932
18	2035	1,730,571	1,542,646	818,562	15,662	235,089	716	4,343,246
19	2036	1,763,270	1,557,602	823,006	15,667	232,971	718	4,393,233
20	2037	1,786,842	1,565,763	828,428	15,670	230,879	716	4,428,297

(a) Figures in years -5 through -1 reflect the impact of historical demand side programs

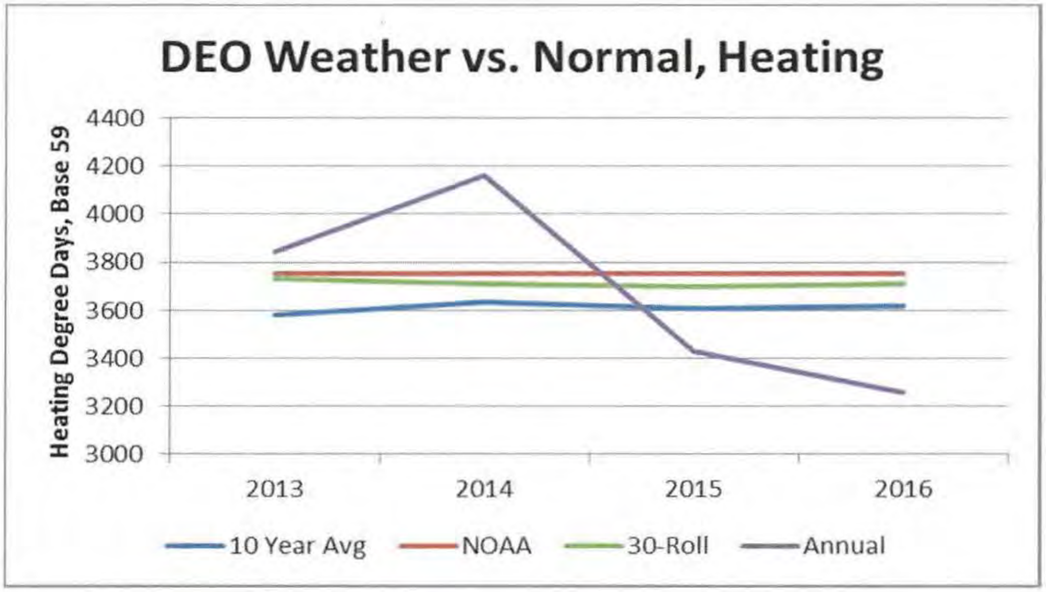
Duke Energy Kentucky
SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) (a,b)

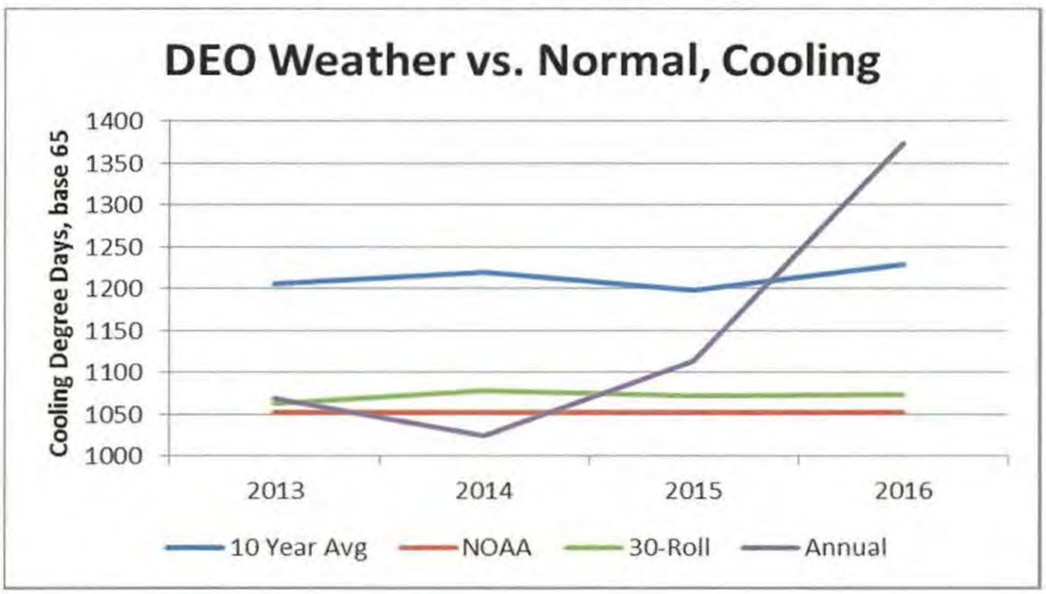
		SUMMER			WINTER (e)		
	YEAR	LOAD	CHANGE (c)	PERCENT CHANGE (d)	LOAD	CHANGE (c)	PERCENT CHANGE (d)
-5	2012	895			710		
-4	2013	869	-26	-2.9%	860	150	21.1%
-3	2014	837	-32	-3.7%	799	-61	-7.0%
-2	2015	814	-23	-2.7%	739	-60	-7.5%
-1	2016	877	63	7.8%	741	2	0.2%
0	2017	845	-32	-3.7%	744	4	0.5%
1	2018	842	-3	-0.4%	749	4	0.6%
2	2019	843	2	0.2%	746	-3	-0.4%
3	2020	843	0	0.0%	741	-4	-0.6%
4	2021	842	-2	-0.2%	704	-37	-5.0%
5	2022	841	-1	-0.1%	703	-1	-0.2%
6	2023	845	4	0.4%	706	3	0.4%
7	2024	850	6	0.7%	684	-21	-3.0%
8	2025	851	1	0.1%	723	38	5.4%
9	2026	855	4	0.4%	728	6	0.8%
10	2027	860	5	0.6%	729	1	0.1%
11	2028	867	7	0.9%	723	-6	-0.9%
12	2029	871	3	0.4%	694	-29	-3.9%
13	2030	873	2	0.3%	696	1	0.2%
14	2031	876	3	0.3%	735	39	5.7%
15	2032	881	6	0.7%	738	3	0.4%
16	2033	887	5	0.6%	736	-1	-0.2%
17	2034	894	7	0.8%	740	4	0.5%
18	2035	902	8	0.9%	716	-23	-3.2%
19	2036	911	9	1.0%	763	47	6.3%
20	2037	919	8	0.9%	774	10	1.4%

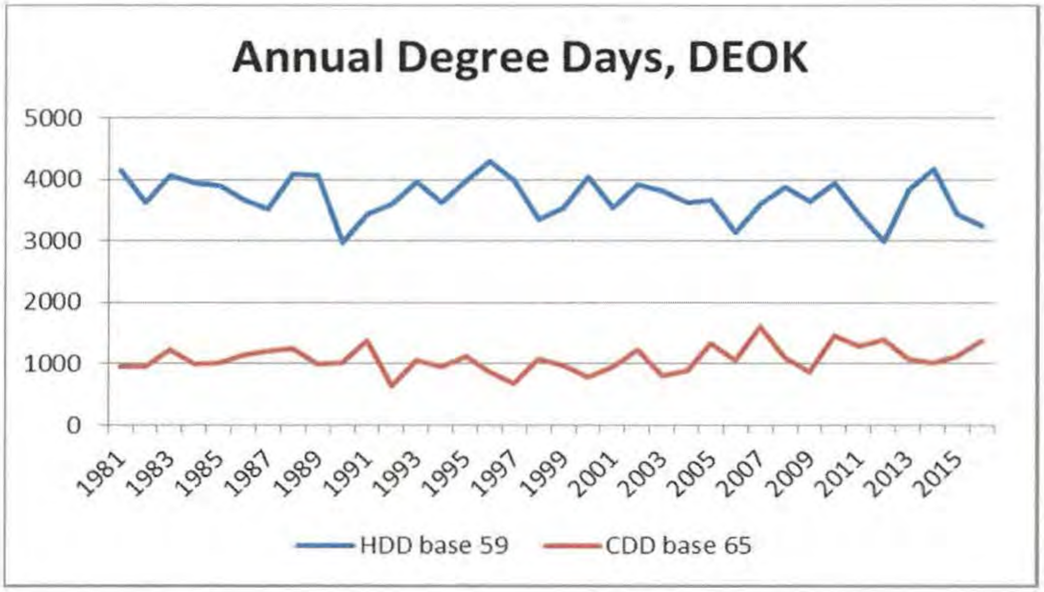
(a) Figures in years -5 through -1—which are not weather-normalized—
reflect the impact of historical demand side programs.
(b) Includes interruptible and demand response load.
(c) Defference between reportin gyear and previous year.
(d) Difference expressed as a percent of previous year.
(e) Winter load reference is to peak loads which occure in the following winter.

Duke Energy Kentucky
RankSort Normal Degree Days (on day of Peak) (a,b)

	Heating Degree Days	Implied Average Temp	Cooling Degree Days	Implied Average Temp
1/1/2017	47.92	11.08	0	--
2/1/2017	40.81	18.19	0	--
3/1/2017	30.15	28.85	0.92	65.92
4/1/2017	18.35	40.65	6.52	71.52
5/1/2017	6.21	52.79	10.66	75.66
6/1/2017	0.06	58.94	15.17	80.17
7/1/2017	0	--	18.89	83.89
8/1/2017	0	--	16.76	81.76
9/1/2017	1.4	57.6	12.99	77.99
10/1/2017	14.18	44.82	4.03	69.03
11/1/2017	25.44	33.56	0.18	65.18
12/1/2017	34.35	24.65	0	--


DEO Weather vs. Normal, Heating
Heating Degree Days, Base 59
4400
4200
4000
3800
3600
3400
3200
3000
2013
2014
2015
2016
10 Year Avg
NOAA
30-Roll
Annual


DEO Weather vs. Normal, Cooling
Cooling Degree Days, base 65
1400
1350
1300
1250
1200
1150
1100
1050
1000
2013
2014
2015
2016
10 Year Avg
NOAA
30-Roll
Annual


Annual Degree Days, DEOK
5000
4000
3000
2000
1000
0
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
HDD base 59
CDD base 65

Direct Testimony of
Anthony J. Platz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-00321

DIRECT TESTIMONY OF

ANTHONY J. PLATZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

September 1, 2017

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Anthony J. Platz, 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 Business Services LLC (DEBS) as Director Power Quality, Reliability and Integrity (PQR&I) Engineering for Kentucky, Ohio, and Indiana. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a bachelor's degree in Electrical Engineering from Rose-Hulman Institute of Technology in 1988 and a Master of Business Administration degree from Xavier University in 2000. I am also a licensed Professional Engineer in the state of Ohio.

I have more than twenty-six (26) years of experience with operating, maintaining, and designing the Company's electric distribution and transmission systems. I joined The Cincinnati Gas & Electric Company (now Duke Energy Ohio) in 1990 as an Electric Planning Engineer where I was responsible for the planning justification of capital improvement projects on the Company's distribution and 69 kilovolt (kV) sub-transmission system. In 1993, I was promoted to the position of Senior Area Engineer where I was responsible for the day-today operation of the distribution system as well as developing reliability improvements. In 1999, I was prompted to the position of Manager, Network Operations where I was responsible for operation and maintenance of the Company's downtown network electrical system, as well as, all primary cable installations in Hamilton County. In 2000 I was promoted to Manager, Transmission & Distribution Operations where I was responsible for the operation of the transmission system and distribution substations. In 2003, I became Manager, Distribution Operations where I was responsible for electric outage management as well as operational engineering. In 2006, I became Manager, Routine and Trouble Operations where I was responsible for implementing and managing the Power Delivery Work Center (PDWC) in Ohio and Kentucky. The PDWC was responsible for all routine customer service order scheduling and the coordination of the Company's natural gas and electric emergency response and storm response coordination. In 2010, I became Director, Distribution Planning where I led a technical staff that was responsible for the long term capability and integrity of the distribution system in the Ohio, Kentucky and Indiana service territories. In 2012, I was promoted to my current position of Director, PQRI Engineering.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR PQR&I ENGINEERING.

A. As Director PQR&I Engineering, I am responsible for a team of technical staff that is responsible for the long-term capability and integrity of the Company's electric distribution system. I am also responsible for the implementation of reliability and integrity programs, customer and system level power quality and reliability investigation and resolution. I also have responsibility for the oversight and execution of the Midwest delivery operations capital improvement budget.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

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

A. The purpose of my testimony is: (1) to describe Duke Energy Kentucky's electric delivery system; (2) to explain Duke Energy Kentucky's overall policies relating to the design, construction, operation and maintenance of the Company's electric delivery facilities; and (3) to explain the need for continued investment in the electric delivery system in order to maintain system reliability. I also sponsor part of the information in the capital budget relating to the Company's local transmission and distribution facilities contained in Filing Requirements (FR) 16(7)(b), FR 16(7)(f) and FR 16(7)(g), which I provided to Duke Energy Kentucky witness Mr. Robert "Beau" Pratt for the forecasted financial data. Finally, I discuss the Company's proposal to introduce a distribution reliability and integrity enhancement program and tracking mechanism and discuss the initiatives the Company will undertake to enhance and improve the safety and reliability of its infrastructure to better meet its customers' growing reliability needs. I sponsor Attachment AJP-1, a list of Duke Energy Kentucky's current Distribution Reliability and Integrity Program Details.

II. DUKE ENERGY KENTUCKY'S ELECTRIC DISTRIBUTION SYSTEM FACILITIES AND POLICIES RELATING TO DESIGN, CONSTRUCTION, OPERATION AND MAINTENANCE OF ITS TRANSMISSION AND DISTRIBUTION SYSTEM

Q. PLEASE GENERALLY DESCRIBE THE DUKE ENERGY KENTUCKY ELECTRIC DELIVERY SYSTEM.

A. Duke Energy Kentucky's electric delivery system is used, among other things, to deliver retail electric service to approximately 140,600 customers located throughout our service area in the Commonwealth of Kentucky, and is spread throughout six counties in the northern part of the Commonwealth. Duke Energy Kentucky owns and operates all of its electric distribution and local transmission facilities. Its parent, Duke Energy Ohio, owns and operates, subject to the functional control of PJM Interconnection, LLC, (PJM) the bulk transmission facilities located in Duke Energy Kentucky's service territory. Duke Energy Kentucky owns, operates, and maintains approximately 107 miles of transmission lines operating at 69 kilovolts (kV) and 2,146 miles of primary distribution lines operating at 34.5 kV or lower and approximately 794 miles of secondary distribution circuits operating at 480 volts or below. The delivery system also includes approximately 43 combined transmission and distribution substations with a combined capacity of approximately 1,852,000 kVA and various other equipment and facilities. The Duke Energy Kentucky electric system is interconnected with East Kentucky Power Cooperative via a 69 kV tie line at the Kenton substation. It is primarily served by transmission facilities within Duke Energy Midwest which, in turn, is directly interconnected with a total of ten transmission owning utilities, the majority of whom are in PJM or Midcontinent Independent System Operator (MISO).

Duke Energy Kentucky's electric delivery system includes various other equipment and facilities such as control rooms, computers, capacitors, street lights, meters, and protective, relay and telecommunications equipment and facilities.

Duke Energy Kentucky electric delivery system provides considerable flexibility for Duke Energy Kentucky to operate in a manner that provides reliable and economic power to our customers.

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM HAS GROWN SINCE DECEMBER 31, 2007 (THE TEST PERIOD FROM DUKE ENERGY KENTUCKY'S LAST RETAIL ELECTRIC RATE CASE).

A. Duke Energy Kentucky's electric delivery system has grown substantially. On December 31, 2007, Duke Energy Kentucky's original cost electric delivery system plant in service was $302,307,606. By December 31, 2016, Duke Energy Kentucky's original cost electric delivery system plant in service had increased to $426,635,808. The Company's forecasted test year (thirteen-month average balance ending March 31, 2019) in this case is projecting the balance to be $485,008,652.

As a further example, since December 31, 2007, Duke Energy Kentucky has installed over 174 circuit-miles of distribution circuits, and 149 kVA of distribution substation transformer capacity. Investments like these have been necessary to maintain safe, reliable, efficient and economical electric delivery service for our existing customers.

Q. IN YOUR OPINION, ARE DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM FACILITIES USED AND USEFUL IN PROVIDING SERVICE TO DUKE ENERGY KENTUCKY'S RETAIL ELECTRIC CUSTOMERS?

A. In my opinion, they are. They are used daily to provide safe, reliable, efficient and economical electric delivery service to our customers.

Q. PLEASE GENERALLY DESCRIBE HOW THE TRANSMISSION AND DISTRIBUTION SYSTEM IS DESIGNED, CONSTRUCTED AND OPERATED.

A. The electric transmission system is designed to deliver bulk electric power from local generating plants and other resources to regional substations, or to interconnect with other systems in order to enhance system reliability. The transmission voltages used by Duke Energy Kentucky are 69 kV and 138 kV. As I previously mentioned, Duke Energy Ohio owns the bulk transmission system in northern Kentucky, consisting of 138 kV and above. There are two 69 kV circuits in Kentucky owned by Duke Energy Kentucky. The system generally consists of steel tower or wood pole transmission lines and substations with power transformers, switches, circuit breakers and associated equipment. The physical design of the system is generally governed by the National Electrical Safety Code (NESC), which I understand is adopted in Kentucky through KRS § 278.042. The bulk transmission system is under the control authority of PJM, a regional transmission organization approved by the Federal Energy Regulatory Commission (FERC). Under PJM's authority, the bulk transmission system is operated in accordance with the reliability standards developed by the North American Electric Reliability Corporation (NERC) and any regional standards developed by ReliabilityFirst Corporation. NERC is the Electric Reliability Organization designated by the FERC under the Federal Power Act to develop mandatory and enforceable reliability standards.

The electric distribution system is designed to receive bulk power at transmission voltages, reduce the voltage to 12.5 kV, and deliver power to customers' premises. The distribution system generally consists of substation power transformers, switches, circuit breakers, wood pole lines, underground cables, distribution transformers, and associated equipment. The physical design of the distribution system is also generally governed by the NESC.

Duke Energy Kentucky operates the transmission and distribution facilities it owns in accordance with good utility practice. Duke Energy Kentucky continuously runs the system with a workforce that works to provide customer service 24 hours per day, seven days per week, 365 days per year, including trouble response crews. Duke Energy Kentucky regulates equipment loading in accordance with good utility practice. The Company monitors outages with various systems, such as Supervisory Control and Data Acquisition (SCADA), Distribution Outage Management System (DOMS), and the Distribution Management System (DMS).

Q. HOW DOES DUKE ENERGY KENTUCKY DISCOVER AND ADDRESS SYSTEM OUTAGES TODAY?

A. Customers typically report outages by telephone through Duke Energy's call center. The call center creates an outage report through a telephone software application that interfaces with DOMS, a state-of-the-art outage management software application that Duke Energy Kentucky implemented in 2011 to improve its ability to monitor and respond to outages. Additionally, some outages are reported automatically through the SCADA system remotely and modeled in DOMS.

DOMS analyzes the calls and identifies for Duke Energy Kentucky's dispatchers the piece of equipment (*e.g.,* circuit breaker, recloser, fuse, and transformer) that is the probable location of the outage. The dispatcher contacts the field trouble response person through the radio system to direct them to the probable equipment location to make repairs and restore electric service. Generally, the field trouble response person inspects the circuit or segment of line in question to identify and report the cause of the outage. The dispatcher records the date, time, duration, and cause of the outage in DOMS.

Dispatchers continuously monitor weather conditions, both in anticipation of and during weather events. When lightning, wind, or ice storms hit Duke Energy Kentucky's service territory, line crews are paged, called, or held over to respond. Duke Energy Kentucky will call in several hundred employees, as necessary, to respond to severe storms, including Duke Energy's utility employees stationed in Kentucky, Ohio, Indiana, North Carolina, South Carolina, and Florida. If necessary, Duke Energy Kentucky will contact other utilities for additional line crews, through a mutual assistance program.

Q. HOW WILL DUKE ENERGY KENTUCKY'S RECENTLY APPROVED AMI DEPLOYMENT IMPACT OUTAGE RESTORATION?

A. The AMI devices will be fully integrated into the DOMs to enable better outage response. Duke Energy Kentucky will be able to "ping" groups of meters or individual meters to better and more efficiently locate outages and determine whether service has been restored for customers. Mass meter pinging can be performed to assess where power is out on the system and, after restoration work is performed, whether all the affected customers have been restored. When the Company is clearing single-outage tickets toward the end of a storm outage event, individual meters can be pinged to confirm whether service has been restored, rather than visiting or calling customers to confirm whether their service has been restored.

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S DISTRIBUTION SYSTEM IS MAINTAINED.

A. Duke Energy Kentucky maintains its distribution infrastructure in accordance with good utility practice by adhering to inspections, monitoring, testing, and periodic maintenance programs. Examples of these existing programs include, but are not limited to, the following: (1) substation inspection program; (2) line inspection program; (3) ground-line inspection and treatment program; (4) vegetation management program; (5) underground cable replacement program; (6) capacitor maintenance program; and (7) dissolved gas analysis in substations.

Attachment AJP-1 is a list and description of Duke Energy Kentucky's current Distribution and Reliability Programs. Duke Energy Kentucky also uses various reliability indices to measure the effectiveness of its maintenance programs and system reliability.

Q. WHAT ARE THE COMPANY'S OBJECTIVES IN DESIGNING, CONSTRUCTING, OPERATING AND MAINTAINING ITS DISTRIBUTION FACILITIES?

A. In designing, constructing, operating and maintaining its facilities, the Company strives to provide safe, cost-effective and reliable electric service.

Q. PLEASE DESCRIBE SOME OF THE FACTORS THAT THE COMPANY MUST CONSIDER IN ATTEMPTING TO ACHIEVE THESE OBJECTIVES.

A. In providing electric service to its customers, the Company must provide safe and reliable service while at the same time prudently and responsibly managing the costs of providing such service. The Company weighs various factors in selecting the electric delivery system projects in which to invest, including the Company's planning criteria, any requirements mandated either by regulatory authorities or reliability councils, and project cost versus customer benefits, to name a few.

Q. HOW DOES THE COMPANY BALANCE ALL OF THESE FACTORS?

A. Annually, electric system studies are performed to determine where and when system modifications are needed to ensure load is adequately served. When these needs are identified, solutions are developed, addressing not only the capacity need, but also providing opportunities to maintain or improve reliability and operating flexibility. Recommendations are made and discussed with the operations staff to ensure a balanced, workable plan has been developed. To support and improve this effort Duke Energy Kentucky uses a distribution system planning software tool that allows for quicker, more detailed analysis of the system.

In the course of maintaining and operating the electric system, equipment and hardware is identified that requires repair or replacement. Specific projects are developed to address areas requiring upgrades and investment. These items are triggered as a result of operating issues, new load growth, or as a result of the various inspection, monitoring, and testing programs I described above.

Q. PLEASE DESCRIBE THE INVESTMENTS THAT DUKE ENERGY KENTUCKY IS MAKING TO ITS DELIVERY SYSTEM TO ENHANCE OR IMPROVE HOW IT PROVIDES SERVICE TO ITS CUSTOMERS.

A. Duke Energy Kentucky strives to provide safe, reliable and affordable utility service twenty four hours a day, seven days a week, and three hundred sixty-five days a year. As customers expect more from the Company, it must invest in the electric delivery system grid to provide increased reliable service. Duke Energy Kentucky will utilize technology that supports faster restoration, effectively decreasing the inconveniences of its customers. The Company is moving from a static grid that may employ limited and pre-determined solutions through manual switching to a self-optimizing grid that responds quickly and automatically to failures and mitigates them by finding the most efficient real-time solution to restore customers. The difference between static and dynamic operation is the use of the real-time data to determine the best solution to restore service. The new grid will use automation and intelligence to manage itself and maximize the reliability customers experience in real time.

Today, the Company's system is constructed for one-way power flow in a radial design with limited ability to integrate renewable energy. As time progresses, this system will eventually evolve into a self-optimizing system. The term self-optimizing grid refers to a series of interconnected and sectionalized distribution circuits that allow for smaller amounts of customers to be affected by faults on the system and shorter duration of outages when those faults occur. These self-optimizing grid investments seek to: (1) increase system "connectivity" by building more circuit ties that allow for more flexibility in restoration options. By tying more circuits together the system will shift from a radial design to more of a "spider web" design; (2) increase "capacity" by installing larger wires and additional system transformers banks to be able to handle dynamic switching and increased two-way power flow from adjacent circuits and renewable generation; and (3) increase "control" through additional system automation and intelligence. Increased automation and intelligence is becoming a necessary requirement to manage an increasingly dynamic system.

With increased connectivity, capacity, and control, the Company will have an increasingly more resilient system with greater flexibility in restoration options. Instead of having circuit pairs that can back each other up, the network allows for multiple options to re-energize circuit segments.

Presently, the Company is slowly and prudently making these investments over time and in the ordinary course of business as its distribution circuits need upgrading due to age, capacity needs, or changes in performance that dictate such an upgrade is desired. The Company projects a need to upgrade approximately five to ten circuits per year as part of normal maintenance and investment. At the present deployment rate, a fully self-optimizing distribution grid capability will take more than a decade to achieve.

III. MEASURING THE RELIABILITY OF DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM

Q. YOU STATED THAT DUKE ENERGY KENTUCKY USES VARIOUS INDICES TO MEASURE THE EFFECTIVENESS OF ITS MAINTENANCE PROGRAMS AND SYSTEM RELIABILITY. PLEASE EXPLAIN THESE RELIABILITY INDICES.

A. These reliability indices are generally recognized standards for measuring the number, scope and duration of outages. These indices are defined as follows:

1) Customer Average Interruption Duration Index (CAIDI) is the average interruption duration or average time to restore service per interrupted customer, and is expressed by the sum of the customer interruption durations divided by the total number of customer interruptions;

2) System Average Interruption Duration Index (SAIDI) is the average time each customer is interrupted, and is expressed by the sum of customer interruption durations divided by the total number of customers served; and

3) System Average Interruption Frequency Index (SAIFI) is the system

average interruption frequency index, and represents the average number of interruptions per customer. SAIFI is expressed by the total number of customer interruptions divided by the total number of customers served.

Q. DOES DUKE ENERGY KENTUCKY REGULARLY REPORT ITS SYSTEM PERFORMANCE TO THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. The Company files annual reliability reports in accordance with the Kentucky Public Service Commission's (Commission) Order in Administrative Case No. 2011-00450 that directed utilities to file annual reliability reports of SAIDI and SAIFI on a system-wide basis showing total circuits and five year averages both including and excluding major event days. The Company also submits circuit reporting identifying which, if any circuits have a SAIDI or SAIFI score that exceeds the five year average, along with an explanation of any corrective actions taken. Additionally, the Company files an annual report of its vegetation management activities.

Q. HOW HAS DUKE ENERGY KENTUCKY'S SYSTEM PERFORMED AS MEASURED BY THESE RELIABILITY INDICES?

A. Duke Energy Kentucky's system has performed well. Duke Energy Kentucky's reliability scores have exceeded industry average reliability scores and are among the best performing throughout Duke Energy's six state electric service areas. The latest reliability index scores available are for calendar year 2016, and are reported below.

Table 1 – 2016 Reliability Indexes

Reliability Index	Duke Energy KY Actual excl. MED	Duke Energy KY Actual w MED
CAIDI	130	172
SAIFI	0.76	1.02
SAIDI	99	175

IV. DUKE ENERGY KENTUCKY'S INVESTMENT IN ITS TRANSMISSIONAND DISTRIBUTION FACILITIES

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S INVESTMENT RELATING TO ITS TRANSMISSION AND DISTRIBUTION FACILITIES DURING THE PAST FEW YEARS AND ITS PROJECTED FUTURE INVESTMENT.

A. The table below summarizes Duke Energy Kentucky's capital expenditures for its transmission and distribution facilities for the period from 2010 through March 31, 2019.

Table 2 – Capital Expenditures 2010-2019

($ millions)	2010	2011	2012	2013	2014	2015	2016	2017	2018	Jan-March 2019
Transmission	0.6	1.1	1.6	0.6	2.6	3.4	1.7	9.3	5.3	1.0
Distribution	15.2	15.1	13.6	16.6	20.3	22.3	23.1	29.8	33.6	8.2
Total	**15.8**	**16.2**	**15.1**	**17.1**	**22.9**	**25.7**	**24.8**	**39.1**	**38.9**	**9.1**

V. MAJOR CHALLENGES FACING DUKE ENERGY KENTUCKY'S ELECTRIC DELIVERY SYSTEM

Q. WHAT ARE THE MAJOR CHALLENGES FACING DUKE ENERGY KENTUCKY'S TRANSMISSION AND DISTRIBUTION SYSTEM?

A. The aging of the electric delivery system is a major challenge. Much of this equipment is over 40 years old. This equipment typically will last from 30–50 years. We expect to incur substantial expenditures to replace this equipment during the next several years. The charts below show the age distribution for Duke Energy Kentucky's poles, distribution circuit breakers, and transmission and distribution transformers.

Figure 1 – Duke Energy Kentucky Distribution Poles Age Distribution Spring 2017

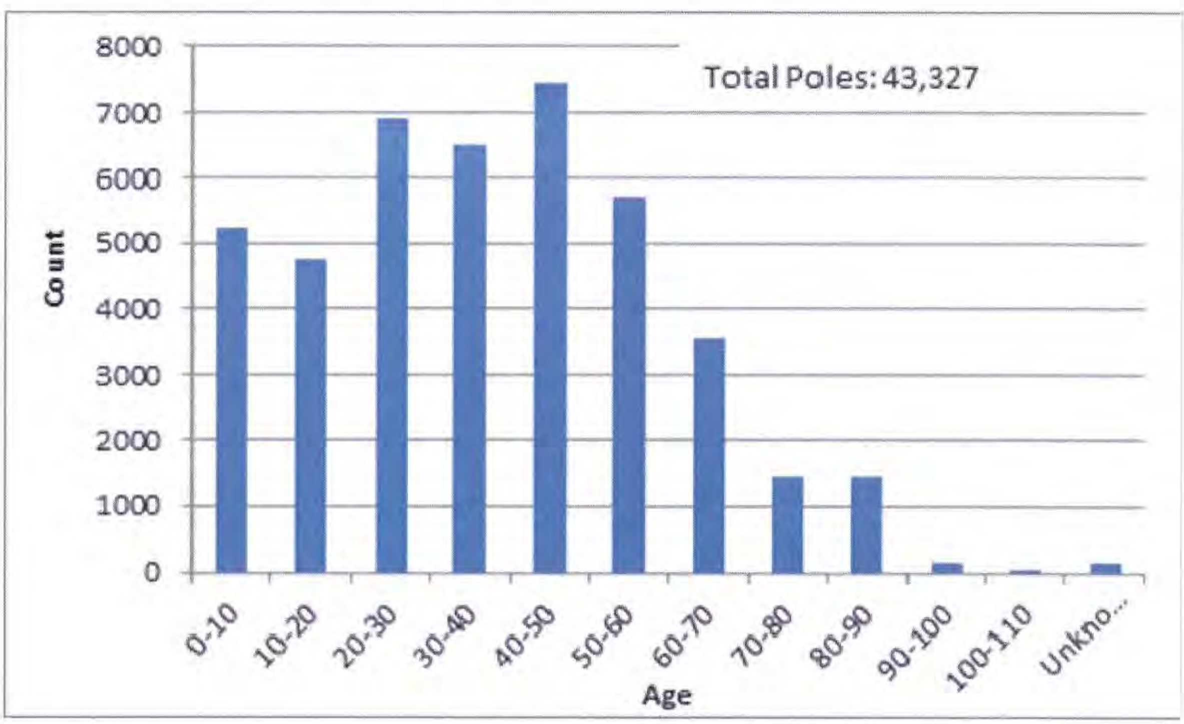


Figure 2 – Duke Energy Kentucky
Distribution Circuit Breakers Age Distribution As Of Spring 2017

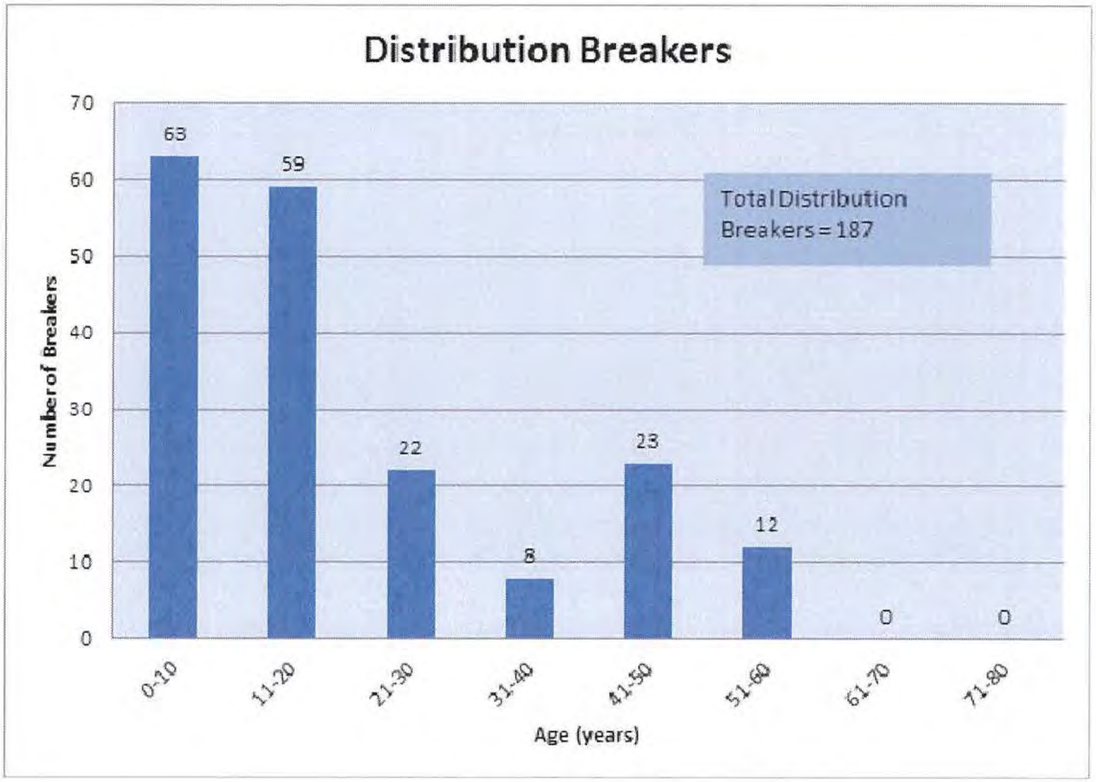
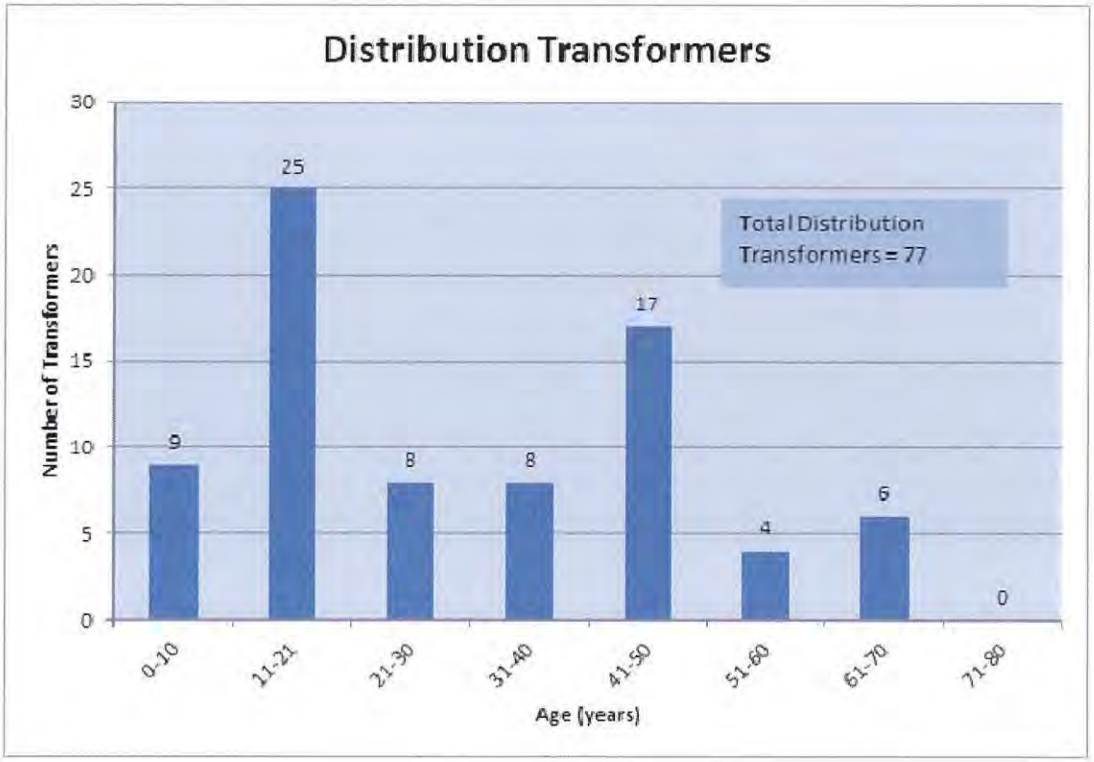


Figure 3 – Duke Energy Kentucky Distribution Transformer Age Distribution as of Spring of 2017



Another challenge Duke Energy Kentucky and other utilities are seeing is that replacement parts are becoming harder to find and, when they are located, can be quite expensive. For example, this very issue surfaced during Hurricane Sandy with Consolidated Edison, Inc., (a/k/a ConEd) reaching out to mutual assistance partners attempting to locate rare fuses.

The Company is also experiencing rising cost pressure for its routine operations and maintenance (O&M) costs such as vegetation management. Presently, the Company's vegetation management strategy contemplates a full system inspection and trim cycle over a four and a half year period. Recently, the Company issued a request for proposal (RFP) for its vegetation management work within the Commonwealth and the indicative bids were returned at close to triple the annual expense from what the Company has previously experienced. This is because vegetation management contractors are resources used by all utilities in the Midwest. So Duke Energy Kentucky is finding itself competing against utilities in surrounding states with less bargaining power.

To help mitigate these rising costs, the Company is moving to a five-year trim cycle and is looking to combine with its sister utilities in the Duke Energy family with the hope of leveraging economies of scale to offer greater contracting opportunities for vendors. The Company believes that moving to a longer term trim cycle will have no impact on the Company's reliability performance.

Q. DO CUSTOMERS' EXPECTATIONS PRESENT A CHALLENGE?

A. Yes. Customers are increasingly using equipment that is highly sensitive to voltage fluctuations; therefore, customers are demanding highly reliable service that minimizes the number of voltage fluctuations. This presents a challenge for Duke Energy Kentucky to strike the correct balance between reliable and economic service.

Q. DOES THE INTRODUCTION OF ADDITIONAL REGULATION PRESENT A CHALLENGE?

A. Yes. As our scores on the reliability indices demonstrate, Duke Energy Kentucky has delivered reliable service under the current regulatory environment. Additional reliability regulations may be imposed that could impose additional compliance costs on the Company. Duke Energy Kentucky supports efforts to maintain and improve distribution system reliability, however, there will certainly be increased costs associated with such improvements.

Q. ARE THE PRACTICES AND PROGRAMS YOU DESCRIBED ABOVE COUPLED WITH THE CURRENT LEVEL OF SPENDING SUFFICIENT FOR THE COMPANY TO MAINTAIN ITS PRESENT LEVEL OF SERVICE RELIABILTY AND MEET CUSTOMER EXPECTATIONS?

A. I do not believe so. Customer expectations are evolving as technology changes. Customers are requiring a higher degree of reliability, performance, and response. Customers are expecting service restorations to be made more quickly, as so much of their daily life depends upon the availability of electricity. This ranges from the ability to power and charge cellular phones, computers, and other mobile devices, in order to maintain communication access, beyond just heating and cooling homes.

Although Duke Energy Kentucky's current practices have served it well in the past, the Company must continue to evolve to meet these growing customer expectations. Duke Energy Kentucky cannot be stagnant and simply rely upon the premise that past practices will continue to be sufficient to maintain future performance. Rather, the Company must adapt its practices and implement new programs to respond to industry demands, changes in technology, and continually evolving customer needs and expectations.

Q. DOES THE COMPANY MEASURE OR ATTEMPT TO QUANTIFY CUSTOMER EXPECTATIONS?

A. Yes. Mr. Henning explains the Company's initiatives to measure customer satisfaction and its performance through both its internal Fastrack post-transaction surveys and national benchmark surveys such as J.D. Power. Mr. Henning further supports the most recent survey data available.

Q. PLEASE DESCRIBE WHAT THE MOST RECENT SURVEYS INDICATE WITH RESPECT TO CUSTOMER EXPECTATIONS, SATISFACTION, AND PERFORMANCE AS IT RELATES TO POWER QUALITY AND RELIEBILITY.

A. The 2017 J.D. Power Electric Utility Residential (EUR) Study confirms once again that Power Quality & Reliability (PQ&R) is the component customers weigh most heavily when determining how satisfied they are with their electric utility. Specifically, 28 percent of their overall Customer Satisfaction rating is based on how they rate their PQ&R experience, outpacing the relative weights of the 'Price' (19 percent), 'Billing & Payment' (19 percent), 'Corporate Citizenship' (16 percent), 'Communications' (14 percent) and 'Customer Service' (5 percent) component performance.

Further, the 2017 J.D. Power EUR Study confirms that customer expectations regarding their PQ&R experience continue to evolve. 'Perfect Power', or the absence of any short/long outages, used to be an attribute that separated top performers from those at the bottom. This year's study shows that there is little separation between the performance of J.D. Power Award Winners

(39 percent Avg. Perfect Power), Overall Industry (39 percent Avg. Perfect Power) and those at the bottom, 4th Quartile in the Industry (37 percent Avg. Perfect Power) as 'Perfect Power' becomes a basic expectation.

The 2017 J.D. Power EUR Study also confirms other customer expectations for their PQ&R Experience, including:

- Customers expect their utilities to provide them robust information about their outage, including:
  - Utility Aware of Outage;
  - Time Outage Began;
  - Number of Customers Out;
  - Estimated time of restoration (ETR);
  - Cause of Outage;
  - Crew Status; and
  - Time Outage Restored.
- Customers expect their utility to deliver this information to them in a timely manner, and to do so proactively, through the channel of their choice. Customers expect to receive accurate ETRs, and for their utility to restore preferably 20 minutes or less before the estimate expires.
- Customers expect their utility to invest in infrastructure maintenance, and to provide them evidence of such investments.

The most recent Fastrack results confirm the direction found in the 2017 J.D. Power Residential Study regarding customer expectation of their PQ&R and

Outage experiences. In short, customers expect reliable service with no outages. If they do experience an outage, our customers expect to receive timely, proactive, accurate, and robust information that is communicated to them in the channel of their choice.

Q. WHAT DO THESE SURVEYS INDICATE IN TERMS OF DUKE ENERGY KENTUCKY'S STRATEGY TO MEET CUSTOMER POWER QUALITY AND RELIABILITY EXPECTATIONS?

A. Even though the majority of Duke Energy Kentucky's customers appear to be satisfied with the Company's overall performance. Customers have low tolerance for outage durations and lack of timely outage information. Even though the Company's reliability scores (CAIDI, SAIDI, and SAIFI) demonstrate the Company is performing well in terms of system reliability, with respect to customer expectations for reliability and power quality, satisfaction scores show there is room for improvement. Duke Energy Kentucky's customers clearly have high expectations of their utility service. Failure to be proactive to resolve issues before they manifest will result in a decline in system performance and customer satisfaction. In order to meet these high expectations, Duke Energy Kentucky must be proactive and take corrective actions before a problem manifests itself. Identifying these issues and employing the necessary resources presents challenges from a budgeting perspective when the sole source of funding for O&M and capital is limited to base rates established through base rate proceedings.

Q. HOW IS THE COMPANY ADAPTING TO ADDRESS CUSTOMER'S HIGH EXPECTATIONS?

A. Duke Energy Kentucky is continually looking for opportunities to enhance and improve its service to customers. One key strategy is making delivery system investments that will enable the Company to better communicate with customers, have better data regarding their usage, and the monitor and improve the health and performance of the electric delivery system. The Company's recently approved AMI deployment initiative will assist with the Company's ability to proactively communicate with its customers.

Q. WHAT IS THE COMPANY PROPOSING IN THESE PROCEEDINGS TO FURTHER INVEST IN THE HEALTH AND PERFORMANCE OF ITS ELECTRIC DELIVERY SYSTEM?

A. Duke Energy Kentucky is proposing to meet these challenges through targeted distribution infrastructure and performance improvement strategies that are approved by the Commission and enabled by a discrete cost recovery mechanism. The distribution infrastructure and performance improvement plan and the associated recovery mechanism, the Distribution Capital Investment reconciliation mechanism (Rider DCI), together balance the interests of: (1) enabling system investments that are designed to maintain or improve integrity and/or reliability; (2) responding to and meeting customer expectations; and (3) allowing the Company to maintain its financial stability.

VI. DUKE ENERGY KENTUCKY'S DISTRIBUTION RELIABILITY AND INTEGRITY INVESTMENT PROGRAM

Q. PLEASE DESCRIBE THE COMPANY'S RIDER DCI PROPOSAL.

A. The Company is proposing to implement a distribution system reliability and integrity improvement initiative that will be comprised of specific new and Commission-approved initiatives designed to enhance the safety, integrity and reliability of its delivery system. As part of this proceeding, the Company is proposing to establish its distribution and integrity plan with a single program, the Targeted Underground Program. As new challenges and solutions are identified, the Company will present these strategies to the Commission for review, consideration for approval and ultimate recovery under the DCI.

Q. WHAT IS THE TARGETED UNDERGROUND PROGRAM?

A. The Targeted Underground Program is the name for a new distribution reliability and integrity enhancing initiative whereby Duke Energy Kentucky proposes to identify specific areas of its distribution system that experience higher than acceptable frequency of outages and replace overhead wires with underground cables in an effort to harden the system, thereby increasing overall reliability. Duke Energy Kentucky's electrical network contains approximately 1,432 miles of overhead distribution lines. These lines contain both backbone feeder conductors, which carry power from electrical substations to neighborhoods, and tap lines (smaller wires) that distribute power throughout those neighborhoods. Duke Energy Kentucky will focus on undergrounding a select subset of these smaller overhead distribution conductors based on a consistent, analytics-based approach that identifies highest likelihood areas in terms of frequency or likelihood of outages.

Within this program, Duke Energy Kentucky is also proposing to take over the ownership of underground service lines that are replaced either as part of the Targeted Underground Program or existing customer-owned underground service lines that experience a failure and are replaced by Duke Energy Kentucky.

Q. WHAT OVERHEAD LINE SEGMENTS ARE CANDIDATES FOR THE TARGETED UNDERGROUND PROGRAM?

A. Duke Energy Kentucky has identified overhead segments with multi-year outlier performance when compared to the remainder of overhead facilities. These underperforming outlier segments drive a disproportionate amount of momentary interruptions (blinks) and outage events that affect all our customers and burden grid assets with life-shortening fault duty and that normal system maintenance strategies have not successfully mitigated. The disparity of performance for these outlier overhead facilities demonstrates that an overhead design approach is not ideal for these specific line segments. Targeted grid investment to "harden" these segments provides broad benefits for all customers while addressing these poor performing areas.

Q. WHAT CAUSES THESE CANDIDATE LINE SEGMENTS TO BE OUTLIERS?

A. These smaller overhead distribution wires or "tap lines" serving neighborhoods and subsets of our cities and communities typically sustain the most damage during storms and require the highest number of repairs. The Targeted

Undergrounding Program is aimed at the exception for our legacy overhead tap line segments where it is demonstrating a consistent pattern of outlier performance.

Q. CAN YOU PROVIDE EXAMPLES TO OF THE TYPES OF LINE SEGMENTS WITH OUTLIER PERFORMANCE?

A. Yes. For one example, Duke Energy Kentucky has identified that the ten percent of circuits experiencing the highest rate of tree-related customer interruptions drive approximately 81 percent of the total system's tree-related customer interruptions. Tree-related customer interruptions make up approximately 18 percent of total customer interruptions for Duke Energy Kentucky. Many of these segments also have limited or no access for vehicle-based restoration and vegetation management support equipment – driving higher costs, longer restoration times, and repeated outages.

Additionally, the ten percent of circuits experiencing the highest rate of customer interruptions caused by public action (*e.g.*, cars crashing into poles) drive nearly 99 percent of all public action customer interruptions across Duke Energy Kentucky's distribution system. Customer interruptions caused by public action account for about 9 percent of all customer interruptions for Duke Energy Kentucky. Since these line segments are typically along major thoroughfares, repairs require shutting down lanes of traffic and putting repair workers at risk of working in high-traffic areas.

Q. HOW WILL DUKE ENERGY KENTUCKY SELECT OVERHEAD LINE SEGMENTS FOR THE TARGETED UNDERGROUND PROGRAM?

A. Locations will be selected based upon potential events eliminated. Locations will then be prioritized based on the following: operational performance; costs (average outage costs); construction designs that are inconsistent with the Company's current standards; and age. Part of the selection process will be to identify circuit segments using Duke Energy Kentucky's outage history records, specifically looking for repeat outage areas.

Q. WHAT ARE THE BENEFITS OF THE TARGETED UNDERGROUND PROGRAM?

A. Undergrounding overhead tap lines may reduce the frequency and duration of outages for Duke Energy Kentucky customers, especially in areas that historically see the most damage in major storms. Restoration in other areas can be accomplished faster due to the material reduction in outage events for these outlier segments of overhead facilities. Faster restoration means life returns to normal more quickly for Duke Energy Kentucky's customers, decreasing the economic impact major storms can have. This program also allows for vegetation management resources to be reallocated to benefit all customers.

Q. WHAT ARE THE COSTS FOR THE TARGETED UNDERGROUND PROGRAM THAT THE COMPANY SEEKS TO RECOVER THROUGH RIDER DCI?

A. If Rider DCI is approved in this case, Duke Energy Kentucky's estimate of its ten year spend on the Targeted Underground Program is summarized below. These high-level cost estimates are projections based upon an average cost per line mile that ranges from $300,000 to $500,000.

Table 3 – Targeted Underground Expenditures 2018-2027

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
($ million)	0	5	5	5	8	8	8	8	10	10

The Company has identified more specific budget details for the first five years of the Targeted Underground Program as follows:

Table 4 – Targeted Underground Expenditures By Category 2018-2022 ($ million)

	2018	2019	2020	2021	2022
Engineering	0.00	0.75	0.75	0.75	1.20
Construction	0.00	3.00	3.00	3.00	4.80
Material	0.00	1.25	1.25	1.25	2.00
Total	0.00	5.00	5.00	5.00	8.00

Q. HOW DOES DUKE ENERGY KENTUCKY'S TARGETED UNDERGROUND PROGRAM ALIGN WITH PREVIOUS COMMISSION DIRECTIVES?

A. In Case No. 2011-00450, the Commission issued its Order on April 1, 2014, to direct utilities to share Corrective Action Plans (if developed) for the 5 percent worst-performing circuits. The Targeted Underground Program focuses on specific overhead line segments, rather than moving entire circuits underground. However, the examples of tree-related and public action-caused customer interruptions reflect the value of focusing on improving service performance at an even more granular level than contemplated by the Commission in its Order.

Q. WHO WILL OWN AND BE RESPONSIBLE FOR INSTALLING UNDERGROUND SERVICES AS PART OF THE TARGETED UNDERGROUNDING PROGRAM?

A. Currently, Duke Energy Kentucky owns and maintains all overhead electric service drops to the customers' premises. However, the underground services remain the sole responsibility of the customers. The Company proposes to change this going forward such that if overhead service is to be moved underground as part of the Targeted Underground Program, Duke Energy Kentucky will install, take ownership of, and be responsible for future maintenance of the underground service going forward. Similarly, the Company is proposing to begin taking ownership of existing customer-owned underground services that are currently owned by customers upon failure and replacement or installation of new services. Therefore, the Company seeks an alteration to its service regulations to allow for this change in underground service ownership.

Q. WHY SHOULD THE COMPANY BEGIN TO ASSUME OWNERSHIP OF EXISTING UNDERGROUND SERVICES UPON REPLACEMENT?

A. Currently, customers that have underground services are responsible for the costs of repairs or replacement if there is a problem. This causes customer confusion and frustration when they learn that the cost to repair such services will be an out of pocket expense, especially when the customer must then choose to either have Duke Energy Kentucky make the replacement or hire their own electrician. By taking over ownership, the Company can provide this service without delay or confusion to its customers.

Q. PLEASE DESCRIBE HOW THE COMPANY WILL RECOVER ITS COSTS FOR THE DISTRIBUTION RELIABILITY AND INTEGRITY PROGRAMS INCLUDED IN DUKE ENERGY KENTUCKY'S INFRASTRUCTURE MODERNIZATION PLAN.

A. Rider DCI will recover the Company's incremental distribution capital investment to implement various specific programs or initiatives designed to maintain and/or enhance the safety, integrity and reliability of the Company's distribution system outside of the Company's base rate test year. The programs to be implemented under the infrastructure performance improvement strategy will be designed to meet customer expectations, manage costs, and proactively address the aging infrastructure issues through a targeted and coordinated approach. Consistent with the intent of Rider DCI, which is to allow the Company to identify and proactively address reliability and integrity issues through a coordinated and targeted strategy, the Company anticipates that Rider DCI will continue to evolve, with technological advances or changes in field conditions, to include additional programs or revisions and modifications to the initial programs over time. The Company proposes to include any proposed program additions for Commission consideration as part of its annual application to adjust and true-up the Rider DCI.

Duke Energy Kentucky witnesses Mr. Wathen and Ms. Lawler fully explain how Rider DCI will work and be adjusted.

Q. WHY IS A DISCRETE RECOVERY MECHANISM APPROPRIATE FOR THESE TYPES OF RELIABILITY AND INTEGRITY PROGRAMS?

A. Duke Energy Kentucky witness William Don Wathen Jr., explains this more fully in his testimony. In short, the discrete mechanism allows the Company to be pro-active and to continually improve its system. As a reliability or integrity initiative is identified, the Company will have the opportunity to come before the Commission to present its case for implementing the program. The ability to have a discrete recovery mechanism will provide funding for these programs, if approved. With traditional base rate recovery model, new programs are only able to be added if the Company is able to find funding within its existing budgets. A discrete mechanism will allow the Company to implement these programs in a more timely fashion, without sacrificing funding for other programs that are included in base rates. Finally, the discrete recovery mechanism will enable the Company to better manage its costs. For example with the proposed targeted underground program, each individual segment identified for an upgrade will require unique design, engineering and costs. A discrete recovery mechanism will enable the Company to have flexibility to operate the program in designing the best solution for each segment.

Q. CAN YOU QUANTIFY THE ANTICIPATED IMPACT TO THE COMPANY'S CURRENT RELIABILITY AND PERFORMANCE THROUGH THE PROPOSED UNDER RIDER DCI?

A. Although Duke Energy Kentucky cannot guarantee that system reliability or customer satisfaction scores will improve due to a particular program or initiative, or that a particular level of system performance will result from implementing its infrastructure improvement plans, doing nothing is sure to erode current levels. There are factors that impact the Company's reliability that are simply beyond its control, such as the frequency and severity of major storms. Nonetheless, the programs selected by the Company to be included in the DCI plan will be designed to address those issues that are predictable and controllable. Proactively addressing vulnerable spots on the distribution system is the most effective way to attempt to improve reliability and will provide benefits to customers.

Q. PLEASE SUMMARIZE THESE CUSTOMER BENEFITS.

A. Through this process, the Company is better able to manage and control its costs and its workforce resources. That should allow for a more efficient operations and restoration processes. The new equipment that replaces and updates the Company's aging distribution equipment will be more resilient to extreme weather conditions and provide greater reliability opportunities. Because many of the programs will be implemented throughout the Company's service territory, ultimately every customer will benefit from these efficiencies and system hardening. Rider DCI and the infrastructure performance improvement programs proposed therein will allow Duke Energy Kentucky to take a holistic, coordinated approach to addressing these identified areas of concern.

Q. ARE YOU AWARE OF OTHER UTILITIES AND REGULATORY JURISDICTIONS THAT HAVE RECOGNIZED THE USE AND USEFULNESS OF DISTRIBUTION INTEGRITY PLANS WITH DISCRETE COST TRACKING AND RECONCILIATION MECHANISMS?

A. Yes. This strategy is being employed in Ohio and Indiana for electric utilities. I am familiar with the programs approved for Duke Energy Kentucky's sister utilities in Ohio and Indiana. I am also aware that every distribution utility in Ohio has a similar mechanism that tracks distribution capital (and in some instances, O&M expense) for system investments. Similarly, Indiana recently approved a comprehensive distribution and transmission infrastructure improvement program for its jurisdictional utilities with discrete recovery outside of a rate case.

Q. IS THE TARGETED UNDERGROUND PROGRAM YOU DESCRIBED ABOVE THE ONLY PROGRAM TO BE INCLUDED IN THE INFRASTRUCTURE MODERNIZATION PLAN?

A. As I previously stated, the Company anticipates that its infrastructure performance improvement plan will continue to evolve with technological advances or changes in field conditions to include additional programs or revisions and modifications over time. The Company would seek Commission authorization through an application to amend the Rider DCI to add additional programs if and when they have been identified. The Company would have the burden to demonstrate these projects are reasonable, in the public interest and would result in a reasonable rate.

The goal is to align the interests of customers in having an electric delivery system that is continually maintaining and improving its integrity and reliability with the Company's need to recover its costs. The Company needs to be able to modify the list of programs and to shift dollars to similar or new programs as technology evolves.

The Company continually strives to find new and better ways to employ technology, proactively address system infrastructure issues in a cost-effective way, and improve reliability.

Q. WHY IS THE FLEXIBILITY TO ADD ADDITIONAL FUTURE PROGRAMS NECESSARY?

A. Programs in Rider DCI will be designed to maintain the integrity of the overall distribution system and, to the extent possible, are also designed to enhance service to Duke Energy Kentucky customers. Duke Energy Kentucky engages in a plan of continuous improvement of its distribution grid and these programs represent vital additions to the Company's efforts to provide safe, affordable, and reliable service to customers. Rider DCI will enable the Company to timely implement new reliability programs, with Commission approval, and in a manner that mitigates the negative earnings impacts that occur when programs are implemented between rate cases, and allows for gradual adjustments of a small component of rates for customers, versus the sudden increase that occurs as result of a base rate case.

Q. ARE THE FORECASTED COSTS DESCRIBED ABOVE AND THE INFRASTRUCTURE AND RELIABILITY IMPROVEMENT PLAN, REASONABLE FOR THE WORK AND SERVICES TO BE PERFORMED?

A. Yes. The costs forecasted for Rider DCI are reasonable and their inclusion in Rider DCI will allow timely recovery of the Company's costs for the programs included therein, to ensure the Company can continue these programs. The rider will be trued-up for actual costs and audited by the Commission to ensure that the Company is not over or under-recovering.

Q. HOW WILL THE COMPANY'S PERFORMANCE UNDER THE INFRASTRUCTURE MODERNIZATION PLAN BE MEASURED?

A. Performance will be measured primarily through the reporting indices I described previously. It is anticipated that these programs will allow the Company to maintain and improve CAIDI, SAIFI, and SAIDI.

VII. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(7)(b).

A. FR 16(7)(b) consists of the most recent capital construction budget containing the forecasted construction expenditures for a minimum of three years. I provided the forecasted capital construction budget for the local transmission and distribution facilities contained in FR 16(7)(b) and for Mr. Pratt's use for the forecasted financial data.

Q. PLEASE DESCRIBE FR 16(7)(f).

A. FR 16(7)(f) includes the following information for major projects constituting five percent or more of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the local transmission and distribution facilities contained in FR 16(7)(f).

Q. PLEASE DESCRIBE FR 16(7)(g).

A. FR 16(7)(g) includes the following information for projects constituting less than five percent of the annual construction budget during the three-year capital expenditure forecast: the starting date and completion date for each project and construction cost per year. I provided this information for the local transmission and distribution facilities contained in FR 16(6)(g).

VIII. CONCLUSION

Q. WAS THE INFORMATION YOU PROVIDED FOR FR 16(7)(b), FR 16(7)(f), AND FR 16(7)(g) AND ATTACHMENT AJP 1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Anthony J. Platz, Director Power Quality, Reliability and Integrity Engineering, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Anthony J. Platz

Anthony J. Platz Affiant

Subscribed and sworn to before me by Anthony J. Platz on this 24th day of August, 2017.

Adele M. Frisch

NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

My Commission Expires: 1/5/2019

Duke Energy Kentucky
Reliability and Integrity Programs

Capital Programs	Description of Program	Location/Area	Area of Benefits	Benefits in Detail
Planned Cable Injection	Refurbishment of underground primary cable via injection of insulating fluid.	Existing underground service area with a primary focus on underground runs of cable that have seen failures and are analyzed by our engineering team determined to be potential candidates for injection.	Customer Experience, Reliability, Integrity	Cable injection is completed for approximately 1/3 of the cost of replacing it. In addition, the technique and product we are using comes with a 25 year warranty to further mitigate future costs. Any time upgrades are needed, outages are needed for cable replacement and can have a lengthy duration however with injection those times are significantly reduced.
Primary Cable Replacement	Replacement of existing UG cable determined to be at end of life and unable to be properly treated. Integrity related program primarily improving SAIDI and CAIDI. Reduction in cable repair O&M	Existing underground service area where cable injection was possibly attempted or determine not to be feasible	Customer Experience, Reliability, Integrity	If injection is not possible this is the last option for the company to replace the underground sections of cable. Due to the soil conditions in Southwest Ohio we have seen the non-jacketed cable where the neutral is deteriorated. SAIDI as well as CAIDI are significantly affected with underground failures and replacement would also offset future O&M costs. In 2013 in Ohio, we implemented a switch and fix program that focuses on trying to look to isolate the cable rather than immediately attempt to splice it.
D Line Pothead Termination	Replacement of potheads terminations and cable back to the first underground device. (Terminators, sometimes called potheads, are installed on the end of underground cable to make the transition to overhead conductor. They will be on the cable at riser (terminal) poles. Terminators are used to control electrical stresses at the end of the cable and to provide an effective seal to prevent leakage of insulating fluids out of the cable and prevent the ingress of moisture into the cable.)	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	• Reduced number of pothead outages. • Liabilities, claims, environmental incident reporting, and system SAIDI component minimized. Equipment operates as designed.
PILC Replacement	Replacement of old paper and lead substation exit cables from the substation to the overhead/underground lines. Cables are approaching end of life and this program would accelerate their replacement.	Duke Energy Ohio Service Area with a primary focus on 13kv substations	Customer Experience, Reliability, Economic Growth, Integrity	PILC cable was a standard installation for many years however with age the oil and papers break down over time. Currently a program exists today for this replacement however with the infrared scans we have determined that we need to accelerate this program. These cables are the first section of a feeder and in most cases if they were to fail would take out two to three thousand customers.
Limited Access Road Crossings	A Limited Access Road is defined as a road or portion of a road where the only access is through on and off ramps at designated entrances/exits (Example: Interstate). Items for review of compliance of Limited Access Crossings: • Insure appropriate cross-arm and pole integrity. • Insure appropriate conductor spacing (horizontal and vertical) to prevent conductor slapping over road. • Insure double dead-end or false dead-end insulators on conductor on road crossings (primary and neutral conductors). • Insure triple guying away from limited across crossing. Insure all the anchor eyes are not buried. • Insure pole, cross-arm, etc. meet NESC grade B construction for loading (EX: Pole Foreman Modeling) and clearances with the existing Duke and joint use conductors/cables attached. o Insure joint use attachments are authorized. o Insure joint use attachments have appropriate guying. o Insure appropriate vertical clearance on joint use cables attached to the pole.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	• Minimize the probability of crossing structural failures. • Increased reliability as long crossing mid span faults are resolved via added horizontal and vertical conductor clearance
GLT Pole Inspection Follow Up	Replacement of Distribution Wood Poles and equipment as part of the Ground Line Inspection Program.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	Resolution of pole inspection follow-up issues prior to actual failure causing an outage event.
Circuit Sectionalization	Ongoing program sectionalizing our distribution feeders allowing the feeders to be broken down into smaller outages rather than all relaying back to a large device.	Duke Energy Ohio Service Area	Customer Experience, Reliability, Economic Growth, Operate, Integrity	Existing program that works in conjunctions with our transformer retrofit program and recloser replacement program breaking down the distribution feeders into smaller circuits with relays and protection schemes. This helps isolate outages to smaller groups and keeps the main lines energized.

Duke Energy Kentucky
Reliability and Integrity Programs

Capital Programs	Description of Program	Location/Area	Area of Benefits	Benefits in Detail
Declared Circuits	A DECLARED CIRCUIT is a backbone feeder, main line, or large recloser subfeeder that needs to be made as secure as possible from probable outage causes, especially sustained outage causes.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	• Reduction in frequency and duration of outages. • Reduction in labor costs with responding to outages. • Reduction in costs associated with reactive measures.
Deteriorated Conductor	The purpose of the Deteriorated/Small Conductor replacement R&I Program is to remove conductor from service that is unreliable. Age alone is not the reason overhead conductor fails. Usually there are other issues related to cable failure. Some of those to review prior to selecting conductor for replacement are: damage due to trees, lightning or auto accidents. Spans are too long or incorrect spacing on the pole or cross arm. The conductor is annealed due to overload conductions in heat or cold load pick up. Steel core of the conductor is corroded. Outage history review of circuits will help pinpoint problem areas. Some of the smallest conductors still in service 6CUBS and 8ACWC have to be de-energized to work on, increasing outage times to customers for routine work.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	• Reduction in frequency and duration of outages. • Reduction in labor costs with responding to outages.
Capacitor Automation	Upgrade of capacitors by adding controls and modem	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Operate, Integrity	• 24/7 monitoring of the health of capacitors on Distributino System • Liabilities, claims, environmental incident reporting, and system SAIDI component minimized. Equipment operates as designed.
Capacitor Cutout Replacement/Cap Oil to Vac Switch Replacement	Changeout of Oil switches to Vacuum switches, cutouts, arresters on capacitor banks.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Operate, Integrity	• Liabilities, claims, environmental incident reporting, and system SAIDI component minimized. Equipment operates as designed. • Increased power quality
Line Patrol Follow up	Replacement of overhead capital items identified through the line patrol inspection.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	• Limits safety hazard from exposure to the public and company employees • Reliability and customer satisfaction • Liabilities, claims, environmental incident reporting, and system SAIDI component minimized. Equipment operates as designed.
Line Patrol SMEI Inspection Follow-up	Replacement of surface mounted equipment capital items identified through the line patrol inspection. Typically replacement of pad mounted cabinets or transformers.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	• Limits safety hazard from exposure to the public and company employees • Reliability and customer satisfaction • Liabilities, claims, environmental incident reporting, and system SAIDI component minimized. Equipment operates as designed.
Recloser Replacements	Currently replace 1/6 of these units annually. This program would accelerate and possibly upgrade some of these devices to electronic controls.	Duke Energy Ohio Service Area	Customer Experience, Reliability, Economic Growth, Operate,	This is an existing program where we change out 1/6 of our reclosers annually. The recloser plays a key role in protecting the main line of the circuit and in making at an attempt to isolate the outge to a smaller group of customers. Annually this encompasses approximately 100
Transformer Retrofits	Continuation of existing transformer retrofit program resulting in fewer transformer related customer outages. This program has a positive business on reduction of O&M restoration costs.	Entire overhead service area where customers are fed with overhead services. Large majority is in older areas, CSP's were prevalent from 1965 thru early 1990's.	Customer Experience, Reliability, Economic Growth, Operate, Integrity	Isolating outages at a transformer level rather than allowing an overloaded or failed transformer to cause a line device to fail or even possibly a substation breaker if fault would occur on the secondary side of the transformer or potentially on the primary lead wire. This program also includes adding an external lighting arrester, squirrel guard, and covered lead wire for additional protection from outages.
Reactive Wood Pole Replacement	Distribution Poles replaced that are NOT related to Ground Line Inspection, Line Inspections, NOT found when performing work for another R&I program and NOT replaced due to work initiated from a DOMS ticket. Typically this would only be poles and cross arms that are "found in field" and not run through DOMS. If work is initiated thru DOM's, then please refer to Outage Follow-up Section for proper project. Field can use if there is an immediate safety issue, otherwise work should be referred to PQR&I Engineering for approval. Also, this does not include poles replaced as a result of public damage.	Duke Energy Kentucky Service Area	Customer Experience, Reliability, Integrity	Resolution of reactive pole replacement issues prior to actual failure causing an outage event.
Reactive Equipment Replacement	Replacement of Distribution Units of Property Capital equipment that are not specifically identified as part of an R&I program and are NOT replaced by work initiated from a DOMS ticket. Typically these capital items would be "found in field" type of items. This does not include Poles and Cross arms. This also includes the replacement of failing DA modems.	Duke Energy Kentucky Service Area	Reliability, Integrity	Resolution of reactive equipment replacement issues prior to actual failure causing an outage event.

Direct Testimony of
Robert ("Beau") H. Pratt

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-00321

DIRECT TESTIMONY OF

ROBERT H. "BEAU" PRATT

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September, 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Robert H. "Beau" 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 Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND 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 Sr. 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 Kentucky, Duke Energy Ohio, Inc., (Duke Energy Ohio) and Duke Energy Indiana, LLC., 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 Kentucky and Duke Energy Ohio.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

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 discuss the budget variance reports, which provide the variance analysis for the test period. I sponsor and support the forecasted operating revenues and expenses prior to proforma adjustments and the long-term financial forecast that were prepared under my direction and control. I sponsor Filing Requirements (FR) 16(6)(a), 16(6)(d), 16(6)(e), 16(7)(b), 16(7)(c), 16(7)(d), 16(7)(f), 16(7)(g), 16(7)(h), and 16(7)(o).

In response to FR 16(8)(b), I sponsor certain information contained in Schedules B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, and B-4 that are supported by Duke Energy Kentucky witness Ms. Cynthia Lee. I sponsor the information contained in B-5 and B-5.1 and certain information contained in Schedule B-8 that is supported by Duke Energy Kentucky witness Mr. David L. Doss. In response to FR 16(6)(a), 16(6)(b) and 16(8)(d), I sponsor Schedules D-2.1 through D-2.15, D-2.28, D-2.30, D-2.34, and D-2.35. I also sponsor the forecasted data on Schedules I-1 through I-5 in response to FR 16(8)(i), and Schedule K in response to FR 16(8)(k).

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 Kentucky's 2016 actual data and its 2017 annual budget. This is because the Company is using a base period that spans two calendar years and is comprised of actual data for 2016 and both actual and budgeted data for 2017. The Company is also using a fully forecasted test period that, for this proceeding, spans the twelve-month period ending March 31, 2019. I supervised the coordination and development of this budget and forecast data, and it was reviewed and approved by Duke Energy Kentucky's executive management and Duke Energy's Board of Directors.

Q. HOW DID YOU USE THE 2017 ANNUAL BUDGET RESULTS FOR THE BASE AND FORECASTED PERIODS IN THIS PROCEEDING?

A. The base period is the twelve months ending November 30, 2017, and consists of six months of actual data through May 2017 and the remaining six months of budgeted data. The forecasted test period is the twelve months ending March 31, 2019. The Company's 2016 actual data and 2017 budget was the starting point for the preparation of both the base and forecasted periods. A simplistic high level summary of that approach is as follows. First, I revised the 2017 Annual Budget for a limited number of updated assumptions, as I describe in detail later in my testimony. Next, I extended the revised 2017 budget to March 2019 using the Company's standard forecasting methodology, which I also describe later in my testimony when I explain how I prepared the financial forecasts. Finally, I updated the revised budget and the forecasted test period with actual data through May 2017.

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

A. 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 KENTUCKY'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 (O&M) budgeting guidelines are reflected in the budgets and forecasts that are submitted to Duke Energy

Kentucky's executive management and Duke Energy's Board of Directors for approval and are also reflected in the forecasted financial data in these proceedings.

Q. WHAT OTHER STEPS ARE INVOLVED IN DEVELOPING THE CORPORATE BUDGET?

A. In addition to the O&M expenses and capital data provided by the budgeting process, other forecasted information is required as follows:

1. Operating revenues;
2. Projected fuel, purchased power, emission allowance, other production costs and off-system sales;
3. Depreciation;
4. Property taxes;
5. Other Income and Expense, primarily allowance for funds used during construction (AFUDC);
6. Financing assumptions, including short- and long-term debt rates, dividend policy, issuances and redemptions, accounts receivable sales and capital leases; and
7. Tax rates and tax depreciation.

III. METHODOLOGY FOR THE FORECASTED DATA

Q. PLEASE DESCRIBE HOW THIS FORECASTED INFORMATION WAS USED FOR THE CORPORATE BUDGET AND LATER REVISED AND/OR EXTENDED THROUGH THE BASE AND FORECAST PERIODS.

A. I will do so by describing the three primary financial statements beginning with the income statement.

A. INCOME STATEMENT

Q. PLEASE DESCRIBE HOW THE OPERATING REVENUES WERE FORECASTED.

A. The first step in preparing the operating revenues for the 2017 annual budget was to obtain a forecast of the projected gas sales on a thousand cubic feet basis (MCF) and electric kilowatt per hour (kWh) sales from Duke Energy Kentucky witness Benjamin Walter Bohdan Passty, Ph.D., Lead Load Forecasting Analyst, who prepared the load forecasts on a monthly basis for each customer class over a ten-year period. The forecasts are updated at least annually. The Load Forecasting and Fundamentals organization also provides the number of customers for each customer class. The projected revenues for the annual budget and the long-range forecast for MCF and kWh sales were calculated by applying the tariff charges to these sales forecast numbers for all gas customers and for residential electric customers. The projected revenue for electric non-residential customers was calculated by applying average realizations to their respective kWh sales forecasts.

Q. ARE THE REVENUE PROJECTIONS BASED ON WEATHER NORMALIZED LOAD FORECASTS?

A. Yes. As described by Dr. Passty, a thirty-year (30) period was used as the basis for calculating normal weather. This is the same methodology that management relies on for preparing its budgets and forecasts, and for financial presentations to the Board of Directors, credit rating agencies, and the investment community.

Q. HOW WERE OTHER REVENUES PROJECTED?

A. Other revenue categories, such as PJM reactive revenues, reconnection charges, late payment fees, *etc.*, for Duke Energy Kentucky's 2017 and 2018 annual budgets are projected based on historical trends or are provided by the individual budget centers. Additionally, Duke Energy Kentucky witness, John Verderame from Duke Energy's Fuels and Systems Optimization Organization, used the GenTrader Model to provide me with forecasts of the power production costs, such as fuel, emission allowances and purchase power costs, and revenues, such as off-system sales, after applying the Company's off-system sales sharing mechanism (Rider PSM).

Q. HOW WERE PRODUCTION COSTS SUCH AS FUEL, EMISSION ALLOWANCES, PURCHASED POWER, AND REVENUES SUCH AS OFF-SYSTEM SALES PROJECTED?

A. As more fully described by Mr. Verderame, the Company utilizes a commercially available production cost model (GenTrader) to develop the forecast utilized in the Company's annual budgets as well as its routine Fuel Adjustment Clause (FAC) filings. All of the Company's generating units are represented in the model with their key characteristics, such as capacity, fuel type, heat rate, and emission rates. Outputs from this model are utilized to project the associated revenues and production costs.

Q. DESCRIBE HOW DEPRECIATION EXPENSE IS INCLUDED IN THE FORECAST.

A. The forecasted depreciation for existing and projected gas and electric plant is calculated by multiplying the depreciable plant by appropriate composite depreciation rates. These composite rates for transmission, distribution, common and general plant are based on rates currently in effect and established in the Company's last base electric rate case, Case No. 2006-00172. Likewise, the depreciation rates used for the East Bend Generating Station (East Bend) and the Woodsdale Generating Station (Woodsdale) (collectively, the Plants) are the same as the depreciation rates approved by the Commission in Case No. 2006-00172.

The projected gas and electric capital budget data was prepared by the responsibility centers for a five-year period at the time of the 2017 Annual Budget preparation per Duke Energy's capital budgeting process, which I discussed earlier. The capital budget data was obtained from Duke Energy's distribution, transmission and fossil/hydro generation organizations, respectively. These numbers were revised to reflect the latest cost estimates and timing of capital expenditures for various projects designed to maintain or enhance reliability and service to customers including several construction projects at the East Bend and Woodsdale stations for various compliance initiatives, as well as the Company's recently approved deployment of an Advanced Metering Infrastructure (AMI). These projects are described in the direct testimonies of Mr. Anthony J. Platz and Mr. Joseph A. Miller, Jr.

Q. DESCRIBE HOW OPERATION AND MAINTENANCE EXPENSES ARE INCLUDED IN THE FORECAST.

A. The O&M expenses, including benefits and payroll taxes, were obtained from the 2017 Annual Budget by the various responsibility centers, using the bottom-up approach that I described above. Duke Energy Kentucky's proportionate share of the shared services expenses and the corporate center O&M expenses are assigned and/or allocated from the service company to Duke Energy Kentucky and are also derived using the same bottom-up approach. The allocated share is derived by the application of appropriate allocations based on the service company allocation factors, and in accordance with various Commission-approved service agreements as discussed in the direct testimony of Duke Energy Kentucky witness, Mr. Jeff Setser. For labor-related expenses, I used the projected annual labor cost rate increases provided by Duke Energy Kentucky witness Mr. Thomas Silinski to budget 2017 and 2018 union and non-union employee labor expense. Union labor cost increases were assumed to be between 1% and 3%, depending on the agreements, while non-union labor cost increases were assumed to be 3.5%. I also used the fringe benefit loading rates (24.2% and 21.1% for 2017 and 2018) and payroll tax (7.65% in each year) loadings. Non-labor expenses for 2017 and 2018 were forecasted by the responsibility centers based on their knowledge and expectations for various costs.

Q. HOW WAS THE O&M REVISED AND EXTENDED THROUGH THE FORECASTED PERIOD?

A. As mentioned above, O&M budgets were supplied by the responsibility centers for 2017 and 2018 per the company's Budget Guidelines. The basis for the 2019 budget is the 2018 budget adjusted for various O&M expenses that are expected to diverge from general escalation assumptions. Apart from these adjustments, O&M expense is assumed to escalate one percent in 2019 from projected 2018 levels.

In certain instances, new or revised information emerged which supported the need for revisions to previously supplied O&M budgets and projections. An example includes vegetation management expenses, which were revised based on updated projections from the responsibility center.

Q. HOW DID YOU OBTAIN THE PROPERTY TAX EXPENSE?

A. The property tax expense was obtained from the 2017 Annual Budget and was prepared as described by Duke Energy's Tax Department. Duke Energy Kentucky witness Ms. Lisa Bellucci supplied the property tax expenses for the forecasted financial test period data, based on the capital projections.

Q. HOW DID YOU OBTAIN THE "OTHER INCOME AND EXPENSE"?

A. The "other income and expense" is a below-the-line item, and is derived from a combination of sources. The amount of funds for the AFUDC was derived from the gas and electric capital forecasts prepared for the 2017 annual budget. These capital forecasts were supplied by Duke Energy Kentucky's transmission and distribution businesses and generating stations.

Q. HOW DID YOU OBTAIN THE INTEREST EXPENSE?

A. Duke Energy Kentucky witness Mr. John L. Sullivan, III, provided the long-term debt balances and long- and short-term interest rates for the revised 2017 annual budget and the 2018 and 2019 forecasts.

Q. HOW DID YOU OBTAIN THE INCOME TAX EXPENSE?

A. Ms. Bellucci provided the appropriate income tax rates and the amortization of investment tax credit (ITC). The income tax expense was derived using Utilities

International (UI) Planner or "proprietary forecasting" software for each month of the revised 2017 annual budget period and the 2018 and 2019 forecasts, by applying statutory income tax rates to applicable taxable book income and adjusting the resulting applicable income taxes by the ITC amortization amounts.

B. BALANCE SHEET STATEMENT

Q. HOW WERE INITIAL BALANCES ESTABLISHED FOR THE BALANCE SHEET?

A. The final month of actual data for the base period was the May 2017 balances. Duke Energy Kentucky witness, Ms. Cynthia A. Lee supplied the net book value for the existing gas, electric and common plant and construction work in progress for the period ending May 2017 for the local transmission and distribution property. I used the proprietary forecasting software to calculate the depreciation expense and net gas, electric, and common plant and construction work in progress balances for the forecasted period.

Q. WHAT OTHER INFORMATION WAS USED TO ESTABLISH THE BASE AND FORECASTED BALANCE SHEETS?

A. Mr. Platz and Mr. Miller provided the capital expenditures for the forecasted portion of the base period and for the forecasted test period. All of the forecasted capital data was prepared for the 2017 Annual Budget and was completed for a five-year period as typically done.

The other assumptions were the dividend policy, the projected changes in long-term debt, the amount of capital lease and equipment lease payments, and the sale of accounts receivable, as provided by Mr. Sullivan, for both the revised

2017 annual budget and the 2018 and 2019 forecasts. In addition, Ms. Lee supplied the Plant inventories for emission allowances, coal, oil and gas and materials and supplies.

C. CASH FLOW STATEMENT

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE 2017 ANNUAL BUDGET?

A. The cash flow statement is generated by Duke Energy's proprietary forecasting software tools. It is derived from corresponding inputs from the income statement and changes in the balance sheet.

IV. REASONABLENESS OF THE FORECASTED TEST PERIOD DATA

Q. DO YOU HAVE AN OPINION AS TO WHETHER THE FORECASTED TEST PERIOD FINANCIAL DATA IS REASONABLE, RELIABLE, MADE IN GOOD FAITH, AND THAT ALL BASIC ASSUMPTIONS USED IN THE FORECAST HAVE BEEN IDENTIFIED AND JUSTIFIED?

A. Yes, the forecasted test period financial data is reasonable, reliable and made in good faith, based on all the information available as of the time of this filing. In my opinion, as Director, Regional Financial Forecasting, the budgeting and forecasting processes are adequate, reasonable, and reliable. My testimony has identified all the basic assumptions in the forecast. These assumptions are justified by my testimony and the testimony of the other witnesses I have identified.

Q. DOES THE FORECAST CONTAIN THE SAME ASSUMPTIONS AND METHODOLOGIES USED IN FORECASTED DATA PREPARED FOR USE BY MANAGEMENT?

A. Yes.

Q. DOES THE FORECASTED TEST PERIOD REFLECT ANY EXPECTED PRODUCTIVITY AND EFFICIENCY GAINS?

A. Yes. The forecasted data reflects all expected productivity and efficiency gains.

V. <u>SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS</u>

Q. PLEASE DESCRIBE FR 16(6)(a)

A. FR 16(6)(a) is the forecasted period in the form of pro forma adjustments to the base period. Our assumptions and methodologies have been described in my testimony as well as other witnesses in this case.

Q. PLEASE DESCRIBE FR 16(6)(d)

A. FR 16(6)(d) requires that there be no revisions to the forecast after filing. The Company will comply with this requirement.

Q. PLEASE DESCRIBE FR 16(6)(e)

A. FR 16(6)(e) provides that the Commission may require the utility to prepare an alternative forecast based upon a reasonable number of changes in the variables, assumptions and other factors used as the basis for the utility's forecast. The Company will comply with this if requested.

Q. PLEASE DESCRIBE FR 16(7)(b).

A. FR 16(7)(b) consists of the Company's most recent capital construction budget containing a minimum three (3) year forecast of construction expenditures.

Q. PLEASE DESCRIBE FR 16(7)(c).

A. FR 16(7)(c) is a summary of the assumptions used to prepare the forecasted test period data. Our assumptions and methodologies have also been described in my testimony and the testimony of other witnesses I identified earlier.

Q. PLEASE DESCRIBE FR 16(7)(d).

A. FR 16(7)(d) is Duke Energy Kentucky's annual and monthly budget for the twelve-months preceding the filing date, the base period and forecasted period.

Q. PLEASE DESCRIBE FR 16(7)(f).

A. FR 16(7)(f) includes specific information for each major construction project that constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast. This information includes the date the project was or is estimated to be started, the estimated completion date, and the total estimated cost of construction by year exclusive and inclusive of AFUDC or interest during construction credit, and the most recent available total costs incurred exclusive and inclusive of AFUDC.

Q. PLEASE DESCRIBE FR 16(7)(g).

A. FR 16(7)(g) includes an aggregate of the information included in FR 16(7)(f) for all construction projects that constitute less than five (5) percent of the annual construction budget within three (3) years of the forecast.

Q. PLEASE DESCRIBE FR 16(7)(h).

A. FR 16(7)(h) is Duke Energy Kentucky's financial forecast corresponding to the three-year capital budget. This includes an income statement, a balance sheet, a statement of cash flow, and certain other required financial and statistical information.

Q. PLEASE DESCRIBE FR 16(7)(o).

A. FR 16(7)(o) consists of management's monthly variance reports for the twelve months prior to the base period, each month of the base period and subsequent months as available. These reports are self-explanatory and include explanations on the variances.

Q. PLEASE DESCRIBE THE INFORMATION YOU SUPPORT IN SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, AND B-4.

A. I provided Ms. Lee with the forecasted data contained in those schedules.

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital calculation based on the Commission's traditional methodology. The calculation includes a cash element of working capital, material and supplies inventory, fuel inventory, and emission allowance inventory.

Q. PLEASE DESCRIBE SCHEDULE B-5.1.

A. Schedule B-5.1 reflects the itemized miscellaneous working capital items for both the base and forecasted periods.

Q. PLEASE EXPLAIN THE MATERIALS AND SUPPLIES INVENTORY ON SCHEDULE B-5.1.

A. The materials and supplies shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of period balance for the base period. These supplies consist primarily of supplies kept on hand in the Company's storerooms. These investments assure that adequate supplies are available to provide reliable service to customers. The 13-month average of material and supplies included in electric working capital for the forecasted test period is $20,474,771.

Q. PLEASE EXPLAIN THE FUEL AND EMISSION ALLOWANCE INVENTORIES ON SCHEDULE B-5.1.

A. The fuel and emission allowance inventories shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of period balance for the base period. The 13-month average balances of fuel and emission allowance inventories included in electric working capital for the forecasted test period are $19,946,203 and $0, respectively. Emission allowance balances have been removed from the forecasted test period since the Company is proposing to include emission allowances for recovery in Rider ESM.

Q. PLEASE EXPLAIN THE CASH WORKING CAPITAL COMPUTATION ON SCHEDULE B-5.1.

A. Cash working capital was computed for both the base and forecasted periods. It represents the financing incurred to bridge the gap between the time when expenditures are incurred to provide service and the time when payment is received for that service. The cash working capital computation is based upon the traditional methodology used by this Commission, which is one-eighth of O&M expense, as adjusted, excluding fuel and purchased power costs. For the base period, the resulting jurisdictional cash working capital is $13,817,614 and for the forecasted period cash working capital is $14,215,407.

Q. PLEASE DESCRIBE SCHEDULE D-2.1.

A. Schedule D-2.1 adjusts base period revenue to the level included in the forecasted test period. The adjustment results in a net revenue decrease of $5,133,384.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts base period purchased power expenses to the level included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's electric operations is a decrease in pre-tax operating expenses of $1,284,619.

Q. PLEASE DESCRIBE SCHEDULE D-2.3.

A. Schedule D-2.3 adjusts base period other production expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $12,650,083.

Q. PLEASE DESCRIBE SCHEDULE D-2.4.

A. Schedule D-2.4 was not used in this filing.

Q. PLEASE DESCRIBE SCHEDULE D-2.5.

A. Schedule D-2.5 adjusts base period transmission expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $919,747.

Q. PLEASE DESCRIBE SCHEDULE D-2.6.

A. Schedule D-2.6 adjusts base period regional market expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $79,447.

Q. PLEASE DESCRIBE SCHEDULE D-2.7.

A. Schedule D-2.7 adjusts base period electric distribution expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $43,555.

Q. PLEASE DESCRIBE SCHEDULE D-2.8.

A. Schedule D-2.8 adjusts base period customer accounts expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $671,968.

Q. PLEASE DESCRIBE SCHEDULE D-2.9.

A. Schedule D-2.9 adjusts base period customer service and information expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $183,121.

Q. PLEASE DESCRIBE SCHEDULE D-2.10.

A. Schedule D-2.10 adjusts base period sales expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $151,501.

Q. PLEASE DESCRIBE SCHEDULE D-2.11.

A. Schedule D-2.11 adjusts base period administrative and general expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $1,497,124.

Q. PLEASE DESCRIBE SCHEDULE D-2.12.

A. Schedule D-2.12 adjusts base period other operating expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase of pre-tax operating expenses of $2,680,605.

Q. PLEASE DESCRIBE SCHEDULE D-2.13.

A. Schedule D-2.13 adjusts base period depreciation expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $9,166,332.

Q. PLEASE DESCRIBE SCHEDULE D-2.14.

A. Schedule D-2.14 adjusts base period taxes other than income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $2,105,609.

Q. PLEASE DESCRIBE SCHEDULE D-2.15.

A. Schedule D-2.15 adjusts base period income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in income tax expense of $1,659,912.

Q. PLEASE DESCRIBE SCHEDULE D-2.28.

A. Schedule D-2.28 is an adjustment for annualization of certain PJM charges and credits to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in fuel-related expense of $774,947.

Q. PLEASE DESCRIBE SCHEDULE D-2.30.

A. Schedule D-2.30 is an adjustment to production maintenance expense for the forecasted test period. The amount included in the Company's forecast was understated. The projected expense to use for the forecasted test year has been updated using an inflation-adjusted average over the last five years of historical data for that account. The effect of the adjustment on electric operations is an increase in test year O&M of $4,777,143.

Q. PLEASE DESCRIBE SCHEDULE D-2.34.

A. Schedule D-2.34 is an adjustment to include a projection of PJM regional transmission expense projects (RTEP) charges and credits expected for the forecasted test year. The original forecast did not include a representative of the Company's expected costs. Using actual billing from PJM and data from PJM, the level of RTEP costs in the test year was adjusted. The effect of the adjustment on electric operations is an increase in test year O&M of $1,979,833.

Q. PLEASE DESCRIBE SCHEDULE D-2.35.

A. Schedule D-2.35 is an adjustment to annualize revenue in the forecasted test period. The overall effect of the adjustment on electric operations is to increase revenues in the forecasted test year by $4,801,375.

Q. PLEASE DESCRIBE SCHEDULES I-1 THROUGH I-5.

A. Schedule I-1 contains comparative income statements for the Company. Schedules I-2.1 through I-5 contains comparative revenue and sales statistical information as required by the Commission's filing requirements.

Q. PLEASE DESCRIBE SCHEDULE K.

A. Schedule K contains comparative financial and statistical information, as required by the Commission's filing requirements. I provided the condensed income statement, on page 2, and the mix of sales and fuel on page 5, for the base period and the forecasted test period.

VI. <u>CONCLUSION</u>

Q. WAS THE INFORMATION YOU SPONSOR IN FR 16(6)(a), 16(6)(b), 16(6)(d), 16(6)(e), 16(7)(b), 16(7)(c), 16(7)(d), 16(7)(f), 16(7)(g), 16(7)(h), 16(7)(o), 16(8)(b), 16(8)(d), 16(8)(i), AND 16(8)(k), THE INFORMATION YOU PROVIDED TO MS. LEE FOR SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, SCHEDULES B-5 AND B-5.1, D-2.1 THRU D-2.15, D-2.28, D-2.30, D-2.34, D-2.35, AS WELL AS SCHEDULES I-1 THORUGH I-5, AND SCHEDULE K PREPARED BY OR SPONSORED AND SUPPORTED BY YOU?

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.

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Robert H. "Beau" Pratt., Director, Regional Financila Forecasting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Robert H. "Beau" Pratt Affiant

Subscribed and sworn to before me by Robert H. "Beau" Pratt on this 9 day of August, 2017.

NOTARY PUBLIC

My Commission Expires:

My Commission Expires
05-30-2018

Direct Testimony of
Bruce L. Sailers

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-00321

DIRECT TESTIMONY OF

BRUCE L. SAILERS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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BLS-1 - Newspaper Notice

BLS-2 - Customer Charge Analysis

BLS-3 - Residential Customer Charge Comparison

BLS-4 - Pole Attachment Calculation

BLS-5 - Reconnection Charge Calculation

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Bruce L. Sailers. 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 Business Services LLC (DEBS), as Pricing and Regulatory Solutions Manager. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor's Degree in Finance and Quantitative Analysis and a Master's Degree in Marketing from the University of Cincinnati. After three years working with Marathon Oil Company as a systems analyst, I began my career with The Cincinnati Gas & Electric Company, a predecessor to Duke Energy Ohio, in Load Forecasting. I worked in the Load Forecasting area for approximately five years in various capacities, and then transferred to Market Research for approximately ten years. In early 2006, I became Manager, Product Development Analytics where I was responsible for demand response product support analysis, certain demand response product operational support functions, demand response product measurement and verification, and demand response product Regional Transmission Organization (RTO) integration for Duke Energy affiliates, including Duke Energy Kentucky. Having these same responsibilities, my title changed to Manager, Retail Energy Desk and then Manager, Demand Response Analytics. I assumed my current role under the title Rates and Regulatory Strategy Manager, Pricing & Rate Options, in January 2014. Having the same responsibilities, my title has since changed to Pricing and Regulatory Solutions Manager.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS PRICING AND REGULATORY SOLUTIONS MANAGER.

A. As Pricing and Regulatory Solutions Manager, I am responsible for performing analyses and studies to support new or revised rates, providing oral and written testimony before regulatory agencies and other regulatory support, meeting with commission staff members in support of filings, rate changes, or tariff administration issues, assisting in administration of rates and programs, preparing or coordinating preparation of required regulatory compliance filings, and leading projects related to new or revised rates.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. Yes. I provided testimony in Case No. 2006-00045 regarding the Commission's investigation into the 2005 Energy Policy Act. In addition, I adopted the testimony of Mr. Timothy Duff in Case No. 2012-00428 regarding the Commission's investigation of smart grid and smart meter technologies. I have also provided testimony in cases before the Indiana Utility Regulatory Commission, the North Carolina Utilities Commission, and the Public Utilities Commission of Ohio.

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

A. I am responsible for Duke Energy Kentucky's proposed electric rate design. My testimony will demonstrate that the rates Duke Energy Kentucky proposes are just and reasonable, that they reflect appropriate rate making principles, and that they result in an equitable basis for recovery of Duke Energy Kentucky's revenue requirements across its various customer classes and rate schedules. I describe changes that have been made to the Company's retail electric rate schedules, riders, and electric Service Regulations and quantify the effect of these changes to our retail electric customers. I sponsor Schedules L, L-1, L-2.1, L-2.2, M, M-2.1 through M-2.3 and N. I also sponsor Filing Requirements (FR) FR 16(1)(b)(3), FR 16(1)(b)(4), FR 16(8)(l), FR 16(8)(m) and FR 16(8)(n). The "L" series of schedules satisfy FR 16(1)(b)(3), FR 16(1)(b)(4), and FR 16(8)(l). The "M" series of schedules satisfies FR 16(8)(m), and the "N" schedule satisfies FR 16(8)(n). Finally, I sponsor the content required in the Company's publication notice under 807 KAR 5:001 Section 17, as reflected in FR 17(4).

II. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULE L.

A. Schedule L has four parts. The first part, identified as Schedule L, is my "Narrative Rationale for Tariff Changes." This schedule describes the changes to Duke Energy Kentucky's current tariffs and the reasons for those changes.

Q. PLEASE DESCRIBE SCHEDULE L-1.

A. Schedule L-1 shows the rate schedules that Duke Energy Kentucky proposes to implement. Please note that schedules related to the Company are pending Demand Side Management (DSM) filing in Case No. 2017-00324 are not presented here. No changes to these schedules are proposed with this filing.

Q. PLEASE DESCRIBE SCHEDULE L-2.1.

A. Schedule L-2.1 contains Duke Energy Kentucky's current rate schedules indicating through underlining and coding where changes occur in the proposed rate schedules. Note that the following schedule sheet numbers only receive an update to the Company President's name and/or the schedule's filing and effective date. There are no substantive changes to these tariff schedules which include sheet numbers 20, 21, 22, 23, 26, 27, 63, 70, 71, 72, 74, 79, 85, 86, 88, 89, 90, and 95. Similar to Schedule L-1, DSM related rate schedules are not presented.

Q. PLEASE DESCRIBE SCHEDULE L-2.2.

A. Schedule L-2.2 contains Duke Energy Kentucky's proposed rate schedules, showing the revisions that Duke Energy Kentucky proposes in this filing. Proposed changes are crossed out and underscored and coded by letter in the right-hand margin. Similar to Schedule L-1, DSM related rate schedules are not presented.

Q. PLEASE DESCRIBE SCHEDULE M.

A. Schedule M is a one page, side-by-side comparison of Duke Energy Kentucky's test period revenues at current and proposed rates; noting that the current fuel adjustment clause (FAC) value is calculated to match fuel revenues in Company's test period revenue requirement in order to remove any revenue variations sourced from fuel cost. Schedule M shows that Duke Energy Kentucky is proposing a 17.4 percent increase in the Residential service class, a 13.9 percent increase in the Distribution Voltage service class, an 11.1 percent increase in the Transmission Voltage service class, and an 11.8 percent increase in the Lighting Service class. These average increases are based upon base rates which include the fuel cost adjustment expense.

Q. PLEASE DESCRIBE SCHEDULE M-2.1.

A. Schedule M-2.1 shows test period base revenue dollars at current rates with the calculated FAC value and the percentage distribution among the various rate classes, as well as a breakdown of total revenue. Schedule M-2.1 also shows the actual base revenue average rates per kilowatt-hour (kWh) for each rate class.

Q. PLEASE DESCRIBE SCHEDULES M-2.2 AND M-2.3.

A. Schedule M-2.2, page 1, shows the test period bills in summary form, base revenues under current rates, current total revenues, and proposed base revenue increases, all broken down by rate and revenue class. The billing determinants used on these schedules is normalized sales for the twelve months ended March 31, 2019. Schedule M-2.2, pages 2 through 20, contains a detailed calculation of test period numbers using current rates as well as the proposed revenue increase, by rate and revenue class, as summarized on Schedule M-2.2, page 1. Schedule M-2.3 is almost identical to M-2.2, page 1, except that it shows the revenue summary and detailed data calculated at the rates proposed in this case.

Q. PLEASE DESCRIBE SCHEDULE N.

A. Schedule N shows monthly bill comparisons for various consumption levels under each of Duke Energy Kentucky's primary tariff schedules, Rates RS, DS, DT, DP, and TT. This schedule allows comparisons and assessment of how these changes impact customers' bills.

Q. PLEASE DESCRIBE FR 16(1)(b)(3).

A. FR 16(1)(b)(3) shows the proposed tariffs in a form complying with 807 KAR 5:011 Section 6. The effective dates of these tariffs are not less than 30 days from the date of the filing of the application in the present case. This filing requirement is met by the L series of schedules I previously described.

Q. PLEASE DESCRIBE FR 16(1)(b)(4).

A. FR 16(1)(b)(4) consists of Duke Energy Kentucky's current tariffs in a comparative form showing proposed changes. The changes are reflected by underscoring additions and striking over deletions. This filing requirement is also met by the L series of schedules I previously described.

Q. PLEASE DESCRIBE FR16(8)(l).

A. FR16(8)(l) includes a narrative description and explanation of all proposed tariff changes. This filing requirement is also met by the L series of schedules I previously described.

Q. PLEASE DESCRIBE FR 16(8)(m).

A. FR 16(8)(m) shows the revenue summary for both the base period and the forecasted period with supporting schedules that provide detailed billing analysis for all customer classes. These schedules show the amount of change requested in dollars and the resulting percentage increase for each customer classification and by each rate classification to which the change will apply. In the present case, Duke Energy Kentucky proposes an overall revenue increase including riders of 14.96 percent, which breaks down as previously described. This filing requirement is met by the M series of schedules.

Q. **PLEASE DESCRIBE FR 16(8)(n).**

A. FR 16(8)(n) shows the typical bill comparison under present and proposed rates for customer classes, current and proposed rates for each customer class, and the rate schedule to which the change would apply.

Q. **PLEASE DESCRIBE FR 17(4)(a).**

A. FR 17(4)(a) shows the proposed effective date and the date the proposed rates are expected to be filed with the Commission. In this case the effective date is October 1, 2017 and the dates the proposed rates are expected to be filed are September 1, 2017.

Q. **PLEASE DESCRIBE FR 17(4)(b).**

A. FR 17(4)(b) shows the present rates and proposed rates for each customer classification to which the proposed rates will apply.

Q. **PLEASE DESCRIBE FR 17(4)(c).**

A. FR 17(4)(c) shows the amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply.

Q. PLEASE DESCRIBE FR 17(4)(d).

A. FR17(4)(d) shows the amount of the average usage and the effect on the average bill for each customer classification to which the proposed rates will apply.

Q. PLEASE DESCRIBE FR 17(4)(e) THROUGH (j)

A. FR17(4)(e) through (j) are statements required for inclusion in the Company's notice to customers, including that customers may examine the Company's application at its offices, at the Commission's offices, or on its website. The statements include instructions for submittal of comments to the Commission and that the rates are only proposed and could be changed by the Commission, as well as instructions for intervention. As evidenced by the Company's Notice, Attachment BLS-1, these various statements are included.

III. RETAIL ELECTRIC RATE SCHEDULES AND RIDERS

A. RATE DESIGN AND MAJOR RETAIL ELECTRIC RATE SCHEDULES

Q. HOW DID YOU DESIGN THE VARIOUS RATE SCHEDULES IN THIS CASE?

A. I used the cost of service information provided by Duke Energy Kentucky witness James E. Ziolkowski as a basis for the rate design. As more fully described in his testimony, the cost of service information provided for the allocation of costs to the various classes, separation of customer and demand components of cost, and further reduced subsidy/excess revenue by 10 percent.

Q. PLEASE DESCRIBE ANY OTHER CONSIDERATIONS THAT GUIDED YOUR RATE DESIGN.

A. First, Duke Energy Kentucky supports the general concept that rates charged to core markets, which includes firm customers in the residential, commercial, industrial and other public authority classes, should approximate the cost of providing these customers with service. This is because it is intrinsically fair that customers should pay rates that reflect the cost that the utility incurs to provide the service. Duke Energy Kentucky's proposed rates in this case make reasonable movement toward reflecting the cost of service developed and sponsored by Mr. Ziolkowski. In particular, the Company proposes increased customer charges for rate schedules RS, DS, DT, EH, SP, and DP to better align the charges with cost causation.

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

A. The Company's major retail electric rate schedules include: Rate RS - Residential Service (Rate RS); Rate DS – Service at Secondary Distribution Voltage (Rate DS); Rate DP – Service at Primary Distribution Voltage (Rate DP); Rate DT - Time of Day Rate for Service at Distribution Voltage (Rate DT); and Rate TT – Time of Day Rate for Service at Transmission Voltage (Rate TT). Together, these rate schedules comprise a substantial portion of the Company's retail electric revenue requirement.

Q. PLEASE DESCRIBE THE COMPANY'S RATE DESIGN OBJECTIVES FOR RATES RS, DS, DP, DT, AND TT.

A. Given the overall percentage increase in this case, our rate design objectives for these rate schedules (hereinafter referred to as "power rate schedules" or "power rates") are to first, generally increase the rates to maintain a similar structure that minimizes impacts to the class of customers, and second, to increase the customer charge component to better reflect the cost of service customer component while collecting the total revenue requirement. Aside from this, there are no significant structural changes to the power rates noting that there is a minor structural change to rate TT. Due to the anticipated future replacement of the Company's billing system, we have chosen to not seek implementation of any significant rate design changes in this case.

Q. WHAT ARE THE PROPOSED CUSTOMER CHARGES?

A. The proposed customer charge for each power rate is as follows: for Rate RS, \$11.22; for Rate DS single phase service, \$17.14; for Rate DS three phase service, \$34.28; for Rate DP, \$118.78; for Rate DT single phase service, \$200.00; for Rate DT three phase service, \$400.00; for Rate DT primary service, \$465.00; and for Rate TT, \$500.00. Attachment BLS-2 sets forth the customer-related costs of providing service to the various customer classes. This information was obtained from the functional cost of service study provided by Mr. Ziolkowski. Attachment BLS-3 shows Company's proposed residential customer charge in comparison to other Kentucky investor owned utility residential customer charges. The Company proposes to move to the customer charges computed from the functional cost of service study while leaving the Rate TT customer charge unchanged. This movement better aligns the recovery of customer related costs with the fixed nature of these costs resulting in a better price signal to customers.

Q. WILL THE PROPOSED INCREASE TO THE CUSTOMER CHARGE FOR RATE RS DISPROPORTIONALLY IMPACT LOW INCOME CUSTOMERS?

A. Duke Energy Kentucky notes that the current rate RS customer charge lags behind current industry trends and is the lowest customer charge in the state among investor-owned utilities. The proposed increase does not appear to be disproportional in comparison to other utilities in Kentucky; see Attachment BLS-3. In addition, the Company reviewed monthly usage of low income (*i.e.*, defined as customers at or below 200 percent of poverty level) customers compared to other customers. The Company reviewed usage primarily to address concerns related to low consumption customers understanding that low consumption and low income are different groups of customers. Mathematically, under the current Rate RS design, a lower usage customer's bill receives a higher percentage increase with the proposed higher customer charge than a higher usage customer. Again, this change provides a better price signal to customers and moves the rate closer to cost causation. The review indicates that low income customers have an average annual usage of 11,059 kWh compared to non-low income customers of 12,395 kWh for calendar year 2016. (Averages are based on customers with twelve months of usage information and greater than or equal to zero kWh.) An average monthly bill calculation under the current and proposed rates for these two usage levels results in an increase of 17.7 percent and 16.9 percent respectively; resulting in a 0.8 percent increase difference.

Q. HAVE YOU PREPARED RATE SCHEDULES FOR THE POWER RATES?

A. Yes. Again, there are no significant structural changes noting the slight change to rate TT. The design objective of the power rates was to collect the revenue requirement while maintaining the existing structural characteristics of the rate schedules. More information can be found on Schedule L.

Q. DESCRIBE THE STRUCTURAL CHANGE TO RATE TT?

A. Currently, the energy component of rate TT has one rate for all kWh. This structure is unlike rate DT where both the energy and demand components provide a price signal to encourage off-peak usage. Given the review of the customer charge component as described above, the Company proposes to collect the same percentage of energy revenue of the total demand and energy revenues from rate TT customers as the current rates but provide a summer and winter on-peak energy rate similar to the structure of rate DT. Since the percentage of revenue will be consistent with the current energy component, the structural change will not harm the rate TT class but will provide a price signal that promotes off-peak usage as compared to on-peak; similar to Rate DT.

B. LIGHTING RATES

Q. WHAT CHANGES TO THE COMPANY'S STREET LIGHTING RATES ARE BEING REQUESTED AS PART OF THIS PROCEEDING?

A. Duke Energy Kentucky is proposing an increase in street lighting rates to recover revenues allocated by the cost of service study. In addition, a new rate design and product offering for light-emitting diode fixtures (LED), Rate LED is proposed for customers.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S CHANGES TO EXISTING STREET LIGHTING RATES.

A. Duke Energy Kentucky proposes to increase the current street lighting rates by the overall percent increase allocated to street lighting customers.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED NEW LED STREET LIGHTING TARIFF.

A. Rate LED provides customers with a variety of LED street and area lighting options. The Company has experience increased customer requests for offering of LED fixtures in lieu of more traditional lighting offers. See Rate LED, Sheet No. 64 for a complete list of options available.

C. MISCELLANEOUS NEW OR REVISED RIDERS

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED NEW RIDER FOR ENVIRONMENTAL COMPLIANCE COSTS.

A. As more fully explained by Duke Energy Kentucky witness William Don Wathen Jr., Duke Energy Kentucky is seeking to implement an environmental surcharge mechanism (Rider ESM) to recover environmental expenses not being recovered in base rates. The new tariff for Rider ESM is included as Sheet No. 76, Rider ESM. The Company is requesting to establish the rider, and set the initial mechanism at zero as part of this case. With the effective date of new rates in this case, expected to be on or about April 1, 2018, the Company will then activate the rider, and make its initial monthly filings to commence recovery of incremental environmental compliance costs for the projects approved and costs incurred as part of the Company's Environmental Compliance Plan.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED CHARGE FOR RECOVERY OF INCREMENTAL BASE TRANSMISSION EXPENDITURES CALLED RIDER FTR.

A. Duke Energy Kentucky is proposing to implement a discrete cost adjustment mechanism (*i.e.*, rider), FERC Transmission Cost Reconciliation Rider (Rider FTR), that would allow recovery of certain ongoing incremental costs for specific transmission related items. Duke Energy Kentucky witnesses Mr. John Swez and Mr. Wathen fully describe the Company's proposal and need for Rider FTR, as well as the list of costs and credits that will be reconciled under the mechanism. Duke Energy Kentucky is proposing to establish Rider FTR in this proceeding and to begin tracking the incremental expenses (above or below levels established in base rates) beginning in 2018. The new tariff is included as Sheet No. 126, Rider FTR. Incremental costs will be recovered through a per kWh charge/credit to customers. Duke Energy Kentucky is proposing to make quarterly adjustment and true-up filings with this Commission.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED CHARGE FOR RECOVERY OF INCREMENTAL DISTRIBUTION CAPITAL EXPENDITURES.

A. Duke Energy Kentucky is proposing to implement a discrete cost adjustment mechanism, Distribution Capital Investment Rider (Rider DCI), that would recover the ongoing incremental capital investments for specific Commission-approved distribution system reliability and integrity enhancement programs. Duke Energy Kentucky witnesses Mr. Anthony Platz, Ms. Sarah Lawler, and Mr. Wathen further describe Rider DCI in their direct testimonies.

Duke Energy Kentucky is proposing to establish the Rider DCI mechanism in this proceeding and to begin recovering the incremental capital investments for its proposed Targeted Underground program starting in April, 2019. Future programs will be submitted to the Commission for review, consideration and approval for inclusion in the Rider. The new rider is included as Sheet No. 125, Rider DCI. Duke Energy Kentucky is proposing to make annual adjustment and true-up filings with this Commission through a process mirroring that used for Duke Energy Kentucky's Accelerated Service Line Replacement Program (Rider ASRP).

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED CHANGES TO ITS FUEL ADJUSTMENT CLAUSE (RIDER FAC).

A. As more fully explained by Duke Energy Kentucky witness Mr. John Swez, the Company is proposing to update its Rider FAC to include eligible fuel and purchased power-related charges and credits that are assessed to the Company by PJM Interconnection LLC (PJM).

IV. <u>OTHER TARIFF CHANGES</u>

Q. WHAT OTHER TARIFF CHANGES IS THE COMPANY PROPOSING IN THIS CASE?

A. Duke Energy Kentucky is proposing several changes to its various tariffs, including changes to its Profit Sharing Mechanism (Rider PSM), Load Management Rider (Rider LM), its cogeneration tariffs for qualifying facilities less than or equal to 100 kW and qualifying facilities greater than 100 kW tariff, Rate CATV, Real Time Pricing, Rate RTP, and its Real Time Pricing - Market-Based Pricing Rate, Rate RTP-M.

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO ITS RIDER PSM.

A. The Company proposes to restructure Rider PSM as fully discussed in the testimony of Duke Energy Kentucky witness Mr. John Verderame as well as in the testimony of Mr. Wathen and Mr. Swez. I have addressed those changes in the language of the tariff.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED CHANGES TO RIDER LM, LOAD MANAGEMENT RIDER.

A. Duke Energy Kentucky no longer utilizes the magnetic tape recording devices which are the subject of Section II in the current Rider LM. Therefore, the Company proposes to eliminate Section II and combine all participants utilizing interval data recorders and time of use meters under Section I.

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO ITS COGENERATION AND SMALL POWER PRODUCTION SALE AND PURCHASE - 100 KW OR LESS TARIFF.

A. The Company is revising the Cogeneration and Small Power Production Sale and Purchase Tariff – 100 kW or Less tariff schedule (referred to as the QF Small Tariff) to be consistent with 807 KAR 5:054. More specifically, the Company revises the Energy Purchase Rate for all kWh delivered. This rate represents avoided energy cost equal to a two-year average PJM LMP at the Duke Energy Kentucky node. The Company intends to recover revenues for these required energy purchases through the FAC as an economy energy purchase. In addition, Company is adding a Capacity Purchase Rate to the QF Small Tariff. The new Capacity Purchase Rate is based on the Company's avoided capacity cost in Company's last filed and Commission reviewed Integrated Resource Plan (IRP) in Case No. 2014-00273. The Company will adjust the Capacity Purchase Rate as the Company files and the Commission completes review of the Company's next IRP, to be filed in June 2018. Additionally, as explained Mr. Verderame, because the Company may need to purchase capacity under this rider to meet its own resource needs in PJM, the Company proposes to reconcile and recover costs of any purchases of capacity under this tariff through Rider PSM.

Q. PLEASE DESCRIBE THE CHANGES THE COMPANY IS PROPOSING TO ITS COGENERATION AND SMALL POWER PRODUCTION SALE AND PURCHASE – GREATHER THAN 100 KW TARIFF.

A. The Company is revising the Cogeneration and Small Power Production Sale and Purchase Tariff – Greater Than 100 kW (referred to as the QF Large Tariff) to be consistent with 807 KAR 5:054. More specifically, the Company maintains the Energy Purchase Rate to be the PJM Real-Time LMP at the Duke Energy Kentucky Aggregate price node for all kWh delivered. The Company proposes to recover revenues for these energy purchases through the FAC. In addition, the Company is adding a Capacity Purchase Rate to the QF Large Tariff. The new Capacity Purchase Rate is based on the Company's avoided capacity cost in the Company's last filed and reviewed IRP. The Company will adjust the Capacity Purchase Rate as the Company files and the Commission completes review of new Company IRPs. The Company proposes to reconcile and recover costs of any purchases of capacity under this tariff through Rider PSM.

Q. PLEASE DESCRIBE THE CHANGES DUKE ENERGY KENTUCKY IS PROPOSING TO ITS CATV RATE.

A. The Company is revising the per foot charge in the CATV rate using the Commission-designated calculation process set forth on September 17, 1982 in Administrative Case No. 251. Calculations for the new per foot pole attachment charges are presented in attachment BLS-4. In addition, Company is broadening the rate language to apply the per foot charge to other pole attachments on a contract basis based on the footage required for the attachment and thus renames the rate to Rate DPA, Distribution Pole Attachment rate.

Q. WHAT CHANGES IS DUKE ENERGY KENTUCKY PROPOSING WITH RESPECT TO ITS RATE RTP-M?

A. Duke Energy Kentucky proposes to terminate this rate. Duke Energy Kentucky has another Real-Time Pricing program available to its non-residential customers, through Rate RTP. The RTP-M rate currently has no customers participating and hasn't received interest from customers for many years. Rate RTP-M was proposed during a time period when the Company purchased all its energy from Duke Energy Ohio which is no longer the case.

Q. WHAT CHANGES IS DUKE ENERGY KENTUCKY PROPOSING WITH RESPECT TO ITS RATE RTP?

A. Duke Energy Kentucky is not proposing structural changes to Rate RTP. The Energy Delivery Charge and Ancillary Services Charge rates are combined and updated using the Company's cost of service study. In addition, the Company corrects an erroneous reference to the "PJM Real-Time Total Locational Marginal Price" noting that the correct reference should be "PJM Day-Ahead Total Locational Marginal Price."

V. MISCELLANEOUS CHARGES

Q. IS THE COMPANY PROPOSING CHANGES TO MISCELLANEOUS CHARGES?

A. Yes. The Company proposes to make changes to the following miscellaneous charges: Meter Data Charges (Rate MDC), Generation Support Service (Rider GSS), and the charge for reconnection of service.

Q. WHAT CHANGES ARE MADE TO THE COMPANY'S METER DATA CHARGES RATE?

A. The Company renames this rate to Meter Data Charges for Enhanced Usage Data Services (Rate MDC). The new name better describes the service provided given the on-going transition of meter equipment. The service provides enhanced graphical capability to non-residential customers through the internet. The name of the software that enables the service also changes from EnFocus to Energy Profiler Online (EPO).

Q. WHAT CHANGES ARE MADE TO THE COMPANY'S RIDER FOR GENERATION SUPPORT SERVICE (RIDER GSS) ?

A. Duke Energy Kentucky is not proposing structural changes to Rider GSS. The Monthly Distribution Reservation Charge and Monthly Transmission Reservation Charge and Monthly Ancillary Services Reservation Charge values are combined and updated using the Company's cost of service study. These values are now included in the combined value called Monthly Transmission and Distribution Reservation Charge.

Q. WHAT CHANGES ARE MADE TO THE COMPANY'S CHARGE FOR RECONNECTION OF SERVICE?

A. Duke Energy Kentucky proposes revision to the charges for reconnection of service as follows.

(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. And if the gas service is also reconnected at the same time as electric service is reconnected at the pole, the charge will be $150.

(5) The incremental charge for reconnection after normal business hours will be an additional $25.

Q. WHAT INFORMATION IS USED TO SUPPORT THE SERVICE RECONNECTION COSTS?

A. Attachment BLS-5 shows the calculation of the hourly labor rate and management estimates of processing time.

Q. DESCRIBE THE INFORMATION PRESENTED IN ATTACHMENT BLS-5, CALCULATION OF RECONNECTION FEES.

A. The reconnection fee calculations use a fully loaded labor rate for craft labor and estimated labor hours to complete reconnection service. The estimated completion times are based on management expertise.

VI. CHANGES TO TARIFF LANGUAGE AND SERVICE REGULATIONS

Q. WHAT CHANGES ARE MADE TO THE COMPANY'S TARIFF LANGUAGE AND SERVICE REGULATIONS?

A. The Company makes changes to its service regulations in Section V, Metering, and Section VI, Billing & Payment. In addition, there are text changes incorporated to Sheet No. 98, Electricity Emergency Procedures for Long-Term Fuel Shortages and Sheet No. 100, Emergency Electric Procedures. Changes are also made to Sheet No. 96, Underground Residential Distribution Policy (Rate UDP-R), and Sheet No. 97, General Underground Distribution Policy (Rate UDP-G).

Q. PLEASE DESCRIBE THE CHANGES DUKE ENERGY KENTUCKY IS PROPOSING TO ITS SERVICE REGULATIONS.

A. In Section VI, Billing & Payment, the Company revises Section VI.6 and VI.7. In Section VI.6, the Company increases flexibility for changing rate schedules primarily with the Fixed Bill Option in mind. As residential customers try Fixed Bill, the Company wishes to provide flexibility for customers to return to Rate RS within a twelve-month period if the customer complies with the Fixed Bill early termination provisions. Section VI.7 revisions broaden the availability of different payment options to incorporate Fixed Bill. In addition in Section V, Metering, Section V.3.1 and V.3.2, are revised to generalize the description of the Hi/Lo customer monthly usage review process. As more detailed data is collected on customers, the Hi/Lo review process can be enhanced. All other changes to the electric Service Regulations are minor corrections such as punctuation.

Q. PLEASE DESCRIBE THE CHANGES DUKE ENERGY KENTUCKY IS PROPOSING TO ITS EMERGENCY PROCEDURES.

A. In Sheet No. 98, Electricity Emergency Procedures for Long-Term Fuel Shortages, the Company removes a reference to generation owned by Duke Energy Ohio. In Sheet No. 100, Emergency Electric Procedures, in order to make these tariff sheets current, the Company replaces references to MISO with PJM and references to ECAR with ReliabilityFirst.

Q. PLEASE DESCRIBE THE CHANGES DUKE ENERGY KENTUCKY IS PROPOSING TO ITS UNDERGROUND DISTRIBUTION POLICY.

A. In Sheet No. 96, Underground Residential Distribution Policy (Rate UDP-R), and Sheet No. 97, General Underground Distribution Policy (Rate UDP-G), the Company adds text to create the ability for Company to pay for and own, with revenues to be recovered in Rider DCI, underground installations associated with the Targeted Underground program discussed by Mr. Platz and Mr. Wathen.

VII. CONCLUSION

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

A. We propose that the revised tariff, including the rates and charges complying with the Commission's order in this Case, be established effective October 1, 2017, for all customers.

Q. WERE SCHEDULES D-2.35, L, L-1, L-2, M, M-2.1 THROUGH M-2.3 AND N AS WELL AS, FR 16(1)(b)(3), FR 16(1)(b)(4), FR 16(8)(l), FR 16(8)(m) AND FR 16(8)(n), FR 17(4) AND ATTACHMENTS BLS-1, BLS-2, BLS-3, BLS-4 AND BLS-5, 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.

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Bruce L. Sailers, Pricing and Regulatory Solutions Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Bruce L. Sailers

Bruce L. Sailers, Affiant

Subscribed and sworn to before me by Bruce L. Sailers, on this 31ST day of JULY, 2017.

Adele M. Frisch

NOTARY PUBLIC

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2019

My Commission Expires: 1/5/2019

NOTICE

Duke Energy Kentucky, Inc. ("Duke Energy Kentucky" or "Company") hereby gives notice that, in an application to be filed no sooner than September 1, 2017, Duke Energy Kentucky will be seeking approval by the Public Service Commission, Frankfort, Kentucky of an adjustment of electric rates and charges proposed to become effective on and after October 1, 2017. The Commission has docketed this proceeding as Case No. 2017-00321.

The proposed electric rates are applicable to the following communities:

Alexandria	Elsmere	Ludlow
Bellevue	Erlanger	Melbourne
Boone County	Fairview	Newport
Bromley	Florence	Park Hills
Campbell County	Fort Mitchell	Pendleton County
Cold Spring	Fort Thomas	Ryland Heights
Covington	Fort Wright	Silver Grove
Crescent Park	Grant County	Southgate
Crescent Springs	Highland Heights	Taylor Mill
Crestview	Independence	Union
Crestview Hills	Kenton County	Villa Hills
Crittenden	Kenton Vale	Walton
Dayton	Lakeside Park	Wilder
Dry Ridge	Latonia Lakes	Woodlawn
Edgewood		

DUKE ENERGY KENTUCKY CURRENT AND PROPOSED ELECTRIC RATES

Residential Service - Rate RS
(Electric Tariff Sheet No. 30)

Current Rate

Customer Charge	$4.50 per month
Energy Charge	
All kilowatt-hours	7.5456¢ per kWh

Proposed Rate

Customer Charge	$11.22 per month
Energy Charge	
All kilowatt-hours	8.3908¢ per kWh

Service at Secondary Distribution Voltage-Rate DS
(Electric Tariff Sheet No. 40)

Current Rate

Customer Charge per month		
Single Phase Service	$ 7.50	per month
Three Phase Service	$15.00	per month
Demand Charge		
First 15 kilowatts	$ 0.00	per kW
Additional kilowatts	$ 7.75	per kW
Energy Charge		
First 6,000 kWh	8.1645¢	per kWh
Next 300 kWh/kW	5.0119¢	per kWh
Additional kWh	4.1043¢	per kWh

Proposed Rate

Customer Charge per month		
Single Phase Service	$ 17.14	per month
Three Phase Service	$34.28	per month
Demand Charge		

First 15 kilowatts	$ 0.00 per kW
Additional kilowatts	$ 8.73 per kW
Energy Charge	
First 6,000 kWh	9.1917¢ per kWh
Next 300 kWh/kW	5.6425¢ per kWh
Additional kWh	4.6204¢ per kWh

Time-of-Day Rate for Service at Distribution Voltage-Rate DT
(Electric Tariff Sheet No. 41)

Current Rate

Customer Charge	
Single Phase	$7.50 per month
Three Phase	$15.00 per month
Primary Voltage Service	$100.00 per month
Demand Charge	
Summer	
On Peak kW	$ 12.75 per kW
Off Peak kW	$ 1.15 per kW
Winter	
On Peak kW	$ 12.07 per kW
Off Peak kW	$ 1.15 per kW
Energy Charge	
Summer	
On Peak kWh	4.4195¢ per kWh
Off Peak kWh	3.6195¢ per kWh
Winter	
On Peak kWh	4.2195¢ per kWh
Off Peak kWh	3.6195¢ per kWh
Metering	
First 1,000 kW of On Peak billing demand at	$ 0.65 per kW.
Additional kW of On Peak billing demand at	$ 0.50 per kW.

Proposed Rate

Base Rate	
Customer Charge	
Single Phase	$ 200.00 per month
Three Phase	$ 400.00 per month
Primary Voltage Service	$ 465.00 per month
Demand Charge	
Summer	
On Peak kW	$ 14.39 per kW
Off Peak kW	$ 1.30 per kW
Winter	
On Peak kW	$ 13.62 per kW
Off Peak kW	$ 1.30 per kW
Energy Charge	
Summer	
On Peak kWh	4.9875¢ per kWh
Off Peak kWh	4.0844¢ per kWh
Winter	
On Peak kWh	4.7612¢ per kWh
Off Peak kWh	4.0844¢ per kWh
Metering	
First 1,000 kW of On Peak billing demand at	$ 0.73 per kW.
Additional kW of On Peak billing demand at	$ 0.56 per kW.

Optional Rate for Electric Space Heating-Rate EH
(Electric Tariff Sheet No. 42)

Current Rate

A. Winter Period

Customer Charge	
Single Phase Service	$ 7.50 per month
Three Phase Service	$ 15.00 per month
Primary Voltage Service	$100.00 per month
Demand Charge	
All kW	$ 0.00 per kW
Energy Charge	
All kWh	6.1524¢ per kWh

Proposed Rate

A. Winter Period

Customer Charge	
Single Phase Service	$ 17.14 per month
Three Phase Service	$ 34.28 per month
Primary Voltage Service	$118.78 per month
Demand Charge	
All kW	$ 0.00 per kW
Energy Charge	
All kWh	6.9947¢ per kWh

Seasonal Sports Service-Rate SP
(Electric Tariff Sheet No. 43)

Current Rate

Customer Charge	$7.50 per month
Energy Charge	10.0598¢ per kWh

A charge of $25.00 is applicable to each season to cover in part the cost of reconnection of service.

Proposed Rate

Customer Charge	$17.14 per month
Energy Charge	10.6568¢ per kWh

A charge of $25.00 is applicable to each season to cover in part the cost of reconnection of service.

Optional Unmetered General Service Rate
For Small Fixed Loans - Rate GS-FL
(Electric Tariff Sheet No. 44)

Current Rate

For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment 8.0723¢ per kWh

For loads of less than 540 hours use per month of the rated capacity of the connected equipment 9.2947 per kWh

Minimum: $3.00 per Fixed Load Location per month.

Proposed Rate

For loads based on a range of 540 to 720 hours use per month of the rated capacity of the connected equipment 9.2698¢ per kWh

For loads of less than 540 hours use per month of the rated capacity of the connected equipment 10.6767¢ per kWh

Minimum: $3.14 per Fixed Load Location per month.

Service at Primary Distribution Voltage Applicability-Rate DP
(Electric Tariff Sheet No. 45)

Current Rate	
Customer Charge per month	
Primary Voltage Service (12.5 or 34.5 kV)	\$100.00 per month
Demand Charge	
All kilowatt	\$ 7.08 per kW
Energy Charge	
First 300 kWh/kW	5.1068¢ per kWh
Additional kWh	4.3198¢ per kWh
Proposed Rate	
Customer Charge per month	
Primary Voltage Service (12.5 or 34.5 kV)	\$118.78 per month
Demand Charge	
All kilowatts	\$ 8.40 per kW
Energy Charge	
First 300 kWh	6.0595¢ per kWh
Additional kWh	5.1267¢ per kWh

Time-of-Day Rate for Service at Transmission Voltage-Rate TT
(Electric Tariff Sheet No. 51)

Current Rate	
Customer Charge per month	\$500.00 per month
Demand Charge	
Summer	
On Peak kW	\$ 7.60 per kW
Off Peak kW	\$ 1.15 per kW
Winter	
On Peak kW	\$ 6.24 per kW
Off Peak kW	\$ 1.15 per kW
Energy Charge	
All kWh	4.2648¢ per kWh
Proposed Rate	
Customer Charge per month	\$500.00 per month
Demand Charge	
Summer	
On Peak kW	\$ 8.46 per kW
Off Peak kW	\$ 1.28 per kW
Winter	
On Peak kW	\$ 6.95 per kW
Off Peak kW	\$ 1.28 per kW
Energy Charge	
Summer	
On Peak kWh	5.4454¢ per kWh
Off Peak kWh	4.4594¢ per kWh
Winter	
On Peak kWh	5.1983¢ per kWh
Off Peak kWh	4.4594¢ per kWh

Rider GSS – Generation Support Service
(Electric Tariff Sheet No. 58)

Current Rate

1. Administrative Charge
   The Administrative Charge shall be $50 plus the appropriate Customer Charge.
2. Monthly Distribution Reservation Charge

a. Rate DS - Secondary Distribution Service	$2.6853 per kW
b. Rate DT – Distribution Service	$2.4735 per kW
c. Rate DP – Primary Distribution Service	$2.7781 per kW
d. Rate TT – Transmission Service	$0.0000 per kVA

3. Monthly Transmission Reservation Charge

a. Rate DS - Secondary Distribution Service	$1.3094 per kW
b. Rate DT – Distribution Service	$1.3047 per kW
c. Rate DP – Primary Distribution Service	$1.8493 per kW
d. Rate TT – Transmission Service	$1.2861 per kVA

4. Monthly Ancillary Services Reservation Charge

a. Rate DS - Secondary Distribution Service	$0.5240 per kW
b. Rate DT – Distribution Service	$0.5240 per kW
c. Rate DP – Primary Distribution Service	$0.5240 per kW
d. Rate TT – Transmission Service	$0.4550 per kVA

Proposed Rate

1. Administrative Charge
   The Administrative Charge shall be $50 plus the appropriate Customer Charge.
2. Monthly Reservation Charge

a. Rate DS - Secondary Distribution Service	$4.8466 per kW
b. Rate DT – Distribution Service	$5.9992 per kW
c. Rate DP – Primary Distribution Service	$6.1484 per kW
d. Rate TT – Transmission Service	$2.9666 per kW

Real Time Pricing –Market –Based Pricing- Rate RTP-M
(Electric Tariff Sheet No. 59)

Current Rate

Secondary Services……. $15.00 per month
Primary Service………….$100.00 per month
Transmission Service........$500.00 per month

Energy Delivery Charge
Charge For Each kW Per Hour:

Secondary Service ……....$0.006053 per kW Per Hour
Primary Service………… $0.005540 per kW Per Hour
Transmission Service…….$0.002008 per kW Per Hour

Ancillary Services Charge shall be applied on an hour by hour basis.
Charge For Each kW Per Hour:

Secondary Delivery …….$0.000760 per kW Per Hour
Primary Delivery ………..$0.000740 per kW Per Hour
Transmission Delivery ….$0.000721 per kW Per Hour

Proposed Rate

CANCELLED & WITHDRAWN

Street Lighting Service-Rate SL
(Electric Tariff Sheet No. 60)

Current Rate

OVERHEAD DISTRIBUTION AREA Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$ 7.11
7,000 lumen (Open Refractor)	175	0.205	853	$ 5.94
10,000 lumen	250	0.275	1,144	$ 8.21
21,000 lumen	400	0.430	1,789	$ 10.99
Metal Halide				
14,000 lumen	175	0.193	803	$ 7.11
20,500 lumen	250	0.275	1,144	$ 8.21
36,000 lumen	400	0.430	1,789	$ 10.99
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 7.87
9,500 lumen (Open Refractor)	100	0.117	487	$ 5.91
16,000 lumen	150	0.171	711	$ 8.58
22,000 lumen	200	0.228	948	$ 11.13
50,000 lumen	400	0.471	1,959	$ 14.95
Decorative Fixtures				
Sodium Vapor				
9,500 lumen (Rectilinear)	100	0.117	487	$9.78
22,000 lumen (Rectilinear)	200	0.246	1,023	$12.09
50,000 lumen (Rectilinear)	400	0.471	1,959	$16.00
50,000 lumen (Setback)	400	0.471	1,959	$23.79

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Spans of Secondary Wiring:
For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.52.

UNDERGROUND DISTRIBUTION AREA Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$7.24
7,000 lumen (Open Refractor)	175	0.205	853	$ 5.94
10,000 lumen	250	0.292	1,215	$ 8.36
21,000 lumen	400	0.460	1,914	$ 11.25
Metal Halide				
14,000 lumen	175	0.210	874	$ 7.24
20,500 lumen	250	0.292	1,215	$ 8.36
36,000 lumen	250	0.292	1,215	$11.25
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 7.87
9,500 lumen (Open Refractor)	100	0.117	487	$ 5.99
16,000 lumen	150	0.171	711	$ 8.55
22,000 lumen	200	0.228	948	$ 11.13
50,000 lumen	400	0.471	1,959	$ 14.95
Decorative Fixtures				
Mercury Vapor				

7,000 lumen (Town & Country)	175	0.205	853	$ 7.48
7,000 lumen (Holophane)	175	0.210	874	$ 9.40
7,000 lumen (Gas Replica)	175	0.210	874	$21.48
7,000 lumen (Granville)	175	0.205	853	$7.56
7,000 lumen (Aspen)	175	0.210	874	$13.61
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$7.48
14,000 lumen (Granville Acorn)	175	0.210	874	$13.61
14,000 lumen (Gas Replica)	175	0.210	874	$21.57
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$10.93
9,500 lumen (Holophane)	100	0.128	532	$11.84
9,500 lumen (Rectilinear)	100	0.117	487	$ 8.83
9,500 lumen (Gas Replica)	100	0.128	532	$ 22.26
9,500 lumen (Aspen)	100	0.128	532	$ 13.79
9,500 lumen (Traditionaire)	100	0.117	487	$ 10.93
9,500 lumen (Granville Acorn)	100	0.128	532	$ 13.79
22,000 lumen (Rectilinear)	200	0.246	1,023	$ 12.15
50,000 lumen (Rectilinear)	400	0.471	1,959	$16.06
50,000 lumen (Setback)	400	0.471	1,959	$23.79

POLE CHARGES

Pole Description	Pole Type	Rate/Pole
Wood		
17 foot (Wood Laminated) (a)	W17	$ 4.40
30 foot	W30	$ 4.34
35 foot	W35	$ 4.40
40 foot	W40	$ 5.27
Aluminum		
12 foot (decorative)	A12	$11.97
28 foot	A28	$ 6.94
28 foot (heavy duty)	A28H	$ 7.01
30 foot (anchor base)	A30	$13.86
Fiberglass		
17 foot	F17	$ 4.40
12 foot (decorative)	F12	$12.87
30 foot (bronze)	F30	$ 8.38
35 foot (bronze)	F35	$ 8.60
Steel		
27 foot (11 gauge)	S27	$ 11.31
27 foot (3 gauge)	S27H	$17.05

Spans of Secondary Wiring:
For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.75.
Base Fuel Cost
All kilowatt-hours shall be subject to a charge of $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

OVERHEAD DISTRIBUTION AREA Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$ 7.96
7,000 lumen (Open Refractor)	175	0.205	853	$ 6.65

10,000 lumen	250	0.275	1,144	$ 9.19
21,000 lumen	400	0.430	1,789	$ 12.30
Metal Halide				
14,000 lumen	175	0.193	803	$ 7.96
20,500 lumen	250	0.275	1,144	$ 9.19
36,000 lumen	400	0.430	1,789	$ 12.30
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 8.81
9,500 lumen (Open Refractor)	100	0.117	487	$ 6.61
16,000 lumen	150	0.171	711	$ 9.60
22,000 lumen	200	0.228	948	$ 12.45
50,000 lumen	400	0.471	1,959	$ 16.73
Decorative Fixtures				
Sodium Vapor				
9,500 lumen (Rectilinear)	100	0.117	487	$ 10.94
22,000 lumen (Rectilinear)	200	0.246	1,023	$ 13.53
50,000 lumen (Rectilinear)	400	0.471	1,959	$ 17.90
50,000 lumen (Setback)	400	0.471	1,959	$ 26.62

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Spans of Secondary Wiring:

For each increment of 50 feet of secondary wiring beyond the first 150 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.58.

UNDERGROUND DISTRIBUTION AREA	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Fixture Description				
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$ 8.10
7,000 lumen (Open Refractor)	175	0.205	853	$ 6.65
10,000 lumen	250	0.292	1,215	$ 9.35
21,000 lumen	400	0.460	1,914	$ 12.59
Metal Halide				
14,000 lumen	175	0.193	803	$ 8.10
20,500 lumen	250	0.275	1,144	$ 9.35
36,000 lumen	400	0.430	1,789	$ 12.59
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 8.81
9,500 lumen (Open Refractor)	100	0.117	487	$ 6.70
16,000 lumen	150	0.171	711	$ 9.57
22,000 lumen	200	0.228	948	$ 12.45
50,000 lumen	400	0.471	1,959	$ 16.73
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$ 8.37
7,000 lumen (Holophane)	175	0.210	874	$ 10.52
7,000 lumen (Gas Replica)	175	0.210	874	$ 24.04
7,000 lumen (Granville)	175	0.210	874	$ 8.46
7,000 lumen (Aspen)	175	0.210	874	$15.23
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$ 8.37
14,000 lumen (Granville Acorn)	175	0.210	874	$ 15.23
14,000 lumen (Gas Replica)	175	0.210	874	$ 24.13
Sodium Vapor				

9,500 lumen (Town & Country)	100	0.117	487	$ 12.23
9,500 lumen (Holophane)	100	0.128	532	$ 13.25
9,500 lumen (Rectilinear)	100	0.117	487	$ 9.88
9,500 lumen (Gas Replica)	100	0.128	532	$ 24.91
9,500 lumen (Aspen)	100	0.128	532	$ 15.43
22,000 lumen (Rectilinear)	200	0.246	1,023	$ 13.59
50,000 lumen (Rectilinear)	400	0.471	1,959	$ 17.97
50,000 lumen (Setback)	400	0.471	1,959	$ 26.62

POLE CHARGES

Pole Description	Pole Type	Rate/Pole
Wood		
17 foot (Wood Laminated) (a)	W17	$ 4.92
30 foot	W30	$ 4.86
35 foot	W35	$ 4.92
40 foot	W40	$ 5.90
Aluminum		
12 foot (decorative)	A12	$ 13.39
28 foot	A28	$ 7.76
28 foot (heavy duty)	A28H	$ 7.84
30 foot (anchor base)	A30	$ 15.51
Fiberglass		
17 foot	F17	$ 4.92
12 foot (decorative)	F12	$ 14.40
30 foot (bronze)	F30	$ 9.38
35 foot (bronze)	F35	$ 9.62
Steel		
27 foot (11 gauge)	S27	$ 12.65
27 foot (3 gauge)	S27H	$ 19.08

Spans of Secondary Wiring:
For each increment of 25 feet of secondary wiring beyond the first 25 feet from the pole, the following price per month shall be added to the price per month per street lighting unit: $0.84.

Base Fuel Cost
The rates per unit shown above include a charge of $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Traffic Lighting Service -Rate TL
(Electric Tariff Sheet No. 61)

Current Rate

Where the Company supplies energy only, all kilowatt-hours shall be billed at 3.8066 cents per kilowatt hour;

Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 2.1078 cents per kilowatt-hour.

Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 5.9145 cents per kilowatt-hour.

Proposed Rate

Where the Company supplies energy only, all kilowatt-hours shall be billed at 4.2590 cents per kilowatt-hour;

Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 2.3583 cents per kilowatt-hour.

Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 6.6174 cents per kilowatt-hour.

Unmetered Outdoor Lighting Electric Service-Rate UOLS
(Electric Tariff Sheet No. 62)

Current Rate

All kWh	3.7481 ¢	per kWh

Proposed Rate

All kWh	4.1936¢	per kWh

Outdoor Lighting Equipment Installation- Rate OL-E
(Electric Tariff Sheet No. 63)

Current Rate

The System Charge is determined by applying the current Levelized Fixed Charge Rate (LFCR), to the Company's cost of purchasing and installing the System.

Proposed Rate

There are no changes to this tariff schedule.

Outdoor Lighting Service- Rate OL
(Electric Tariff Sheet No. 65)

Current Rate

	Lamp Watts	kW/ Luminaire	Annual kWh	Rate/Unit
Standard Fixtures (Cobra Head)				
Mercury Vapor				
7,000 lumen (Open Refractor)	175	0.205	853	$ 8.73
7,000 lumen	175	0.210	874	$11.17
10,000 lumen	250	0.292	1,215	$13.04
21,000 lumen	400	0.460	1,914	$16.75
Metal Halide				
14,000 lumen	175	0.210	874	$11.17
20,500 lumen	250	0.307	1,215	$13.06
36,000 lumen	400	0.460	1,914	$16.75
Sodium Vapor				
9,500 lumen (Open Refractor)	100	0.117	487	$ 7.68
9,500 lumen	100	0.117	487	$ 9.99
16,000 lumen	150	0.171	711	$ 11.27
22,000 lumen	200	0.228	948	$ 12.47
27,500 lumen	200	0.228	948	$ 12.47
50,000 lumen	400	0.471	1,959	$ 14.53
Decorative Fixtures (a)				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$ 13.38
7,000 lumen (Holophane)	175	0.210	874	$17.24
7,000 lumen (Gas Replica)	175	0.210	874	$41.66
7,000 lumen (Aspen)	175	0.210	874	$25.77
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$21.10
9,500 lumen (Holophane)	100	0.128	532	$22.86
9,500 lumen (Rectilinear)	100	0.117	487	$18.79
9,500 lumen (Gas Replica)	100	0.128	532	$43.94
9,500 lumen (Aspen)	100	0.128	532	$26.63
9,500 lumen (Traditionaire)	100	0.117	487	$21.10
9,500 lumen (Granville Acorn)	100	0.128	532	$26.63
22,000 lumen (Rectilinear)	200	0.246	1,023	$22.37
50,000 lumen (Rectilinear)	400	0.471	1,959	$28.38

50,000 lumen (Setback)	400	0.471	1,959	$44.15

B. Flood lighting units served in overhead distribution areas (FL):

Mercury Vapor				
21,000 lumen	400	0.460	1,914	$16.76
Metal Halide				
20,500 lumen	250	0.307	1,215	$13.04
36,000 lumen	400	0.460	1,914	$16.76
Sodium Vapor				
22,000 lumen	200	0.246	1,023	$ 12.38
30,000 lumen	250	0.312	1,023	$ 12.38
50,000 lumen	400	0.480	1,997	$ 15.35

Proposed Rate

CANCELLED & WITHDRAWN

Street Lighting Service for Non-Standard Units -Rate NSU
(Electric Tariff Sheet No. 66)

Current Rate

Company owned

	Lamp Watts	kW/Unit	Annual kW/unit	Rate/Unit
Boulevard units served underground				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$ 9.22
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$ 7.16
Holophane Decorative fixture on 17 foot fiberglass pole served underground with direct buried cable				
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$16.79

The cable span charge of $.75 per each increment of 25 feet of secondary wiring shall be added to the Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$ 7.10
b. 2,500 lumen Mercury Vapor	100	0.109	453	$ 6.72
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$ 10.66

Customer owned

Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$5.44
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$6.92

Base Fuel Cost

The rates per unit shown above include $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

Company owned

	Lamp Watts	kW/Unit	Annual kW	Rate/Unit
Boulevard units served underground				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$ 10.32
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$ 8.01
Holophane Decorative fixture on 17 foot fiberglass pole served underground with direct buried cable				
a. 10,000 lumen Mercury Vapor	250	0.292	1,215	$18.79

The cable span charge of $.84 per each increment of 25 feet of secondary wiring shall be added to the

Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$ 7.94
b. 2,500 lumen Mercury Vapor	100	0.109	453	$ 7.52
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$ 11.93
Customer owned				
Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$ 6.09
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$ 7.74

Base Fuel Cost

The rates per unit shown above include $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Private Outdoor Lighting for Non-Standard Units-Rate NSP
(Electric Tariff Sheet No. 67)

Current Rate

Private outdoor lighting units:

The following monthly charge will be assessed for existing facilities, but this unit will not be available to any new customers after May 15, 1973:

	Lamp Watt	kW Unit	Annual kWh	Rate/Unit
2,500 lumen Mercury, Open Refractor	100	0.115	478	$ 7.79
2,500 lumen Mercury, Enclosed Refractor.....	100	0.115	478	$ 10.66

Outdoor lighting units served in underground residential distribution areas:

The following monthly charge will be assessed for existing fixtures which include lamp and luminaire, controlled automatically, with an underground service wire not to exceed 35 feet from the service point, but these units will not be available to new customers after May 5, 1992:

	Lamp Watt	kW/Unit	Annual kWh	Rate/Unit
7,000 lumens Mercury, Mounted on a 17-foot Fiberglass Pole	175	0.205	853	$14.54
7,000 lumen Mercury, Mounted on a 17-foot Wood Laminated Pole (a)..........	175	0.205	853	$14.54
7,000 lumen Mercury, Mounted on a 30-foot Wood Pole......................	175	0.205	853	$13.44
9,500 lumen Sodium Vapor, TC 100 R........	100	0.117	487	$ 11.22

(a) Note: New or replacement poles are not available.

Flood lighting units served in overhead distribution areas:

The following monthly charge will be assessed for each existing fixture, which includes lamp and luminaire, controlled automatically, mounted on a utility pole, as specified by the Company, with a span of wire not to exceed 120 feet, but these units will not be available after May 5, 1992:

	Lamp Watts	kW/Fixture	Annual kWh	Rate/Unit
52,000 lumen Mercury (35-foot Wood Pole)....	1,000	1.102	4,584	$28.55
52,000 lumen Mercury (50-foot Wood Pole)....	1,000	1.102	4,584	$32.16
50,000 lumen Sodium Vapor............	400	0.471	1,959	$19.79

Base Fuel Cost

All kilowatt-hours shall be subject to a charge of $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

CANCELLED & WITHDRAWN

Street Lighting Service-Customer Owned - Rate SC
(Electric Tariff Sheet No. 68)

Current Rate

	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Fixture Description				
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$ 4.19
10,000 lumen	250	0.275	1,144	$ 5.33
21,000 lumen	400	0.430	1,789	$ 7.40
Metal Halide				
14,000 lumen	175	0.193	803	$ 4.19
20,500 lumen	250	0.275	1,144	$ 5.33
36,000 lumen	400	0.430	1,789	$ 7.40
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 5.04
16,000 lumen	150	0.171	711	$ 5.62
22,000 lumen	200	0.228	948	$ 6.17
27,500 lumen	250	0.228	948	$ 6.17
50,000 lumen	400	0.471	1,959	$ 8.36
Decorative Fixture				
Mercury Vapor				
7,000 lumen (Holophane)	175	0.210	874	$ 5.32
7,000 lumen (Town & Country)	175	0.205	853	$ 5.27
7,000 lumen (Gas Replica)	175	0.210	874	$ 5.32
7,000 lumen (Aspen)	175	0.210	874	$ 5.32
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$ 5.27
14,000 lumen (Granville Acorn)	175	0.210	874	$ 5.32
14,000 lumen (Gas Replica)	175	0.210	874	$ 5.32
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$ 4.96
9,500 lumen (Traditionaire)	100	0.117	487	$ 4.96
9,500 lumen (Granville Acorn)	100	0.128	532	$ 5.18
9,500 lumen (Rectilinear)	100	0.117	487	$ 4.96
9,500 lumen (Aspen)	100	0.128	532	$ 5.18
9,500 lumen (Holophane)	100	0.128	532	$ 5.18
9,500 lumen (Gas Replica)	100	0.128	532	$ 5.18
22,000 lumen (Rectilinear)	200	0.246	1,023	$ 6.54
50,000 lumen (Rectilinear)	400	0.471	1,959	$ 8.65

Where a street lighting fixture served overhead is to be installed on another utility's pole on which the Company does not have a contact, a monthly pole charge will be assessed.

Pole Description	Pole Type	Rate/Pole
Wood		
30 foot	W30	$4.34
35 foot	W35	$4.40
40 foot	W40	$5.27

Base Fuel Cost

The rates per unit shown above include $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate

	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Fixture Description				
Standard Fixture (Cobra Head)				

Mercury Vapor				
7,000 lumen	175	0.193	803	$ 4.69
10,000 lumen	250	0.275	1,144	$ 5.96
21,000 lumen	400	0.430	1,789	$ 8.28
Metal Halide				
14,000 lumen	175	0.193	803	$ 4.69
20,500 lumen	250	0.275	1,144	$ 5.96
36,000 lumen	400	0.430	1,789	$ 8.28
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 5.64
16,000 lumen	150	0.171	711	$ 6.29
22,000 lumen	200	0.228	948	$ 6.90
27,500 lumen	250	0.228	948	$ 6.90
50,000 lumen	400	0.471	1,959	$ 9.35
Decorative Fixture				
Mercury Vapor				
7,000 lumen (Holophane)	175	0.210	874	$ 5.95
7,000 lumen (Town & Country)	175	0.205	853	$ 5.90
7,000 lumen (Gas Replica)	175	0.210	874	$ 5.95
7,000 lumen (Aspen)	175	0.210	874	$ 5.95
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$ 5.90
14,000 lumen (Granville Acorn)	175	0.210	874	$ 5.95
14,000 lumen (Gas Replica)	175	0.210	874	$ 5.95
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$ 5.55
9,500 lumen (Traditionaire)	100	0.117	487	$ 5.55
9,500 lumen (Granville Acorn)	100	0.128	532	$ 5.80
9,500 lumen (Rectilinear)	100	0.117	487	$ 5.55
9,500 lumen (Aspen)	100	0.128	532	$ 5.80
9,500 lumen (Holophane)	100	0.128	532	$ 5.80
9,500 lumen (Gas Replica)	100	0.128	532	$ 5.80
22,000 lumen (Rectilinear)	200	0.246	1,023	$ 7.32
50,000 lumen (Rectilinear)	400	0.471	1,959	$ 9.68

Pole Description	Pole Type	Rate/Pole
Wood		
30 foot	W30	$ 4.86
35 foot	W35	$ 4.92
40 foot	W40	$ 5.90

Base Fuel Cost

The rates per unit shown above include $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Street-lighting Service-Overhead Equivalent-Rate SE
(Electric Tariff Sheet No. 69)

Current Rate:

Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$7.29
7,000 lumen (Holophane)	175	0.210	874	$7.32
7,000 lumen (Gas Replica)	175	0.210	874	$7.32
7,000 lumen (Aspen)	175	0.210	874	$7.32
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$7.29

14,000 lumen (Granville Acorn)	175	0.210	874	$7.32
14,000 lumen (Gas Replica)	175	0.210	874	$7.32
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$7.95
9,500 lumen (Holophane)	100	0.128	532	$8.05
9,500 lumen (Rectilinear)	100	0.117	487	$7.95
9,500 lumen (Gas Replica)	100	0.128	532	$8.04
9,500 lumen (Aspen)	100	0.128	532	$8.04
9,500 lumen (Traditionaire)	100	0.117	487	$7.95
9,500 lumen (Granville Acorn)	100	0.128	532	$8.04
22,000 lumen (Rectilinear)	200	0.246	1,023	$11.42
50,000 lumen (Rectilinear)	400	0.471	1,959	$15.11
50,000 lumen (Setback)	400	0.471	1,959	$15.11

Base Fuel Cost

All kilowatt-hours shall be subject to a charge of $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Proposed Rate:

	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Fixture Description				
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$8.16
7,000 lumen (Holophane)	175	0.210	874	$8.19
7,000 lumen (Gas Replica)	175	0.210	874	$8.19
7,000 lumen (Aspen)	175	0.210	874	$8.19
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$8.16
14,000 lumen (Granville Acorn)	175	0.210	874	$8.19
14,000 lumen (Gas Replica)	175	0.210	874	$8.19
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$8.89
9,500 lumen (Holophane)	100	0.128	532	$9.01
9,500 lumen (Rectilinear)	100	0.117	487	$8.89
9,500 lumen (Gas Replica)	100	0.128	532	$9.00
9,500 lumen (Aspen)	100	0.128	532	$9.00
9,500 lumen (Traditionaire)	100	0.117	487	$8.89
9,500 lumen (Granville Acorn)	100	0.128	532	$9.00
22,000 lumen (Rectilinear)	200	0.246	1,023	$12.78
50,000 lumen (Rectilinear)	400	0.471	1,959	$16.91
50,000 lumen (Setback)	400	0.471	1,959	$16.91

Base Fuel Cost

The rates per unit shown above include $0.023837 per kilowatt-hour reflecting the base cost of fuel.

Rider PPS – Premier Power Service Rider
(Electric Tariff Sheet No. 70)

Current Rate:

Rate

Each qualifying customer's individual monthly rate calculated for each customer for this service will be determined as follows:

Monthly Service Payment = Estimated Levelized Capital Cost + Estimated Expenses

Where:

Levelized Capital Cost is equal to the present value of all estimated capital related cash flows for a period corresponding to the time of engineering, design and installation of equipment through the term of the contract, adjusted to a pre-tax amount and converted to a uniform monthly payment for the term of the contract. The estimated capital cash flows shall include estimated installed cost of equipment, contingency allowances, salvage value, adjustment to reflect additional supporting investment of general plant nature, and income tax impacts.

Expenses shall equal the present value of estimated expenses associated with the support and maintenance of the generation and support equipment, adjusted to a pre-tax amount and converted to a uniform monthly payment for the term of the contract. The estimated expenses shall include administrative and general expenses, expenses for labor and materials related to operations and maintenance, third party expenses for operations and maintenance, warranties, insurance, annual costs associated with working capital, fuel inventory, depreciation, property tax, other costs related to the operation and support of the generator system installation, and income tax impacts.

The after tax cost of capital from the Company's most recent general rate case will be used to convert present values to uniform monthly payments.

MONTHLY BILL

Customer's monthly bill for all services under this rider will appear on their regular monthly electric bill as a line item.

Proposed Rate:

There are no proposed changes in this rider.

Rider TS – Temporary Service Rider
(Electric Tariff Sheet No. 71)

Current Rate:

In addition to charges for service furnished under the applicable standard rate the customer will pay in advance the following charge:

Estimated unit cost of each service with supporting data to be filed with the Commission and updated annually by the utility.

Proposed Rate:

There are no proposed changes in this rider.

Rider X – Line Extension Policy Rider
(Electric Tariff Sheet No. 72)

Current Rate:

When the estimated cost of extending the distribution lines to reach the customer's premise equals or is less than three (3) times the estimated gross annual revenue the Company will make the extension without additional guarantee by the customer over that applicable in the rate, provided the customer establishes credit in a manner satisfactory to the Company.

When the estimated cost of extending the distribution lines to reach the customer's premise exceeds three (3) times the estimated gross annual revenue, the customer may be required to guarantee, for a period of five (5) years, a monthly bill of one (1) percent of the line extension cost for residential service and two (2) percent for non-residential service.

When the term of service or credit have not been established in a manner satisfactory to the Company, the customer may be required to advance the estimated cost of the line extension in either of the above situations. When such advance is made the Company will refund, at the end of each year, for four (4) years, twenty-five (25) percent of the revenues received in any one year up to twenty-five (25) percent of the advance.

Proposed Rate:

There are no proposed changes in this rider.

Rider LM – Load Management Rider
(Electric Tariff Sheet No. 73)

Current Rate:

I. When a customer elects the OFF PEAK PROVISION, the monthly customer charge of the applicable Rate DS will be increased by an additional monthly charge of five dollars ($5.00) for each installed time-of-use meter. In addition, the DEMAND provision of Rate DS shall be modified to the extent that the billing demand shall be based upon the "on peak period," as defined above.

II. For customers who meet the Company's criteria for the installation of a magnetic tape recording device for billing, and where electric service is furnished under the provisions of either Rate DS, Service at Secondary Distribution Voltage, or Rate DP, Service at Primary Distribution Voltage. When a customer elects this OFF PEAK PROVISION, the applicable monthly customer charge of Rate DS or Rate DP will be increased by an additional monthly charge of one hundred dollars ($100.00).

Proposed Rate:

When a customer elects the OFF PEAK PROVISION, the monthly customer charge of the applicable Rate DS or DP will be increased by an additional monthly charge of five dollars ($5.00) for each installed time-of-use or interval data recorder meter. In addition, the DEMAND provision of Rate DS or DP shall be modified to the extent that the billing demand shall be based upon the "on peak period," as defined above. However, in no case shall the billing demand be less than the billing demand as determined in accordance with the DEMAND provision of the applicable Rate DS or Rate DP, as modified.

Rider AMO – Advanced Meter Opt-Out (AMO) - Residential
(Electric Tariff Sheet No. 74)

Current Rate:

CHARGES

Residential customers who elect, at any time, to opt-out of the Company's advanced metering infrastructure (AMI) system shall pay a one-time fee of $100.00 and a recurring monthly fee of $25.00. During the Metering Upgrade project deployment phase, if prior to an advanced meter being installed at a customer premise, any existing residential electric customer that elects to participate in this opt-out program, Duke Energy Kentucky will not charge the one-time set-up fee, providing the residential electric customer notifies the Company of such election in advance of the advanced meter being installed. Those residential customers electing to participate in this residential opt-out program will be subject to the ongoing $25.00 per month ongoing charge. Following deployment completion, any residential customer who later elects to participate in the Opt-Out Program will be assessed the $100 set-up fee in addition to the ongoing monthly charge.

Proposed Rate:

There are no proposed changes in this rider.

Rider DSMR – Demand Side Management Rate
(Electric Tariff Sheet No. 78)

Current Rate:

The Demand Side Management Rate (DSMR) shall be determined in accordance with the provisions of Rider DSM, Demand Side Management Cost Recovery Rider, Sheet No. 75 of this Tariff.

The DSMR to be applied to residential customer bills is $0.007967 per kilowatt-hour.

A Home Energy Assistance Program (HEA) charge of $0.10 will be applied monthly to residential customer bills through December 2020.

The DSMR to be applied to non-residential distribution service customer bills is $0.002576 per kilowatt-hour.

The DSMR to be applied for transmission service customer bills is $0.000183 per kilowatt-hour.

Proposed Rate:

There are no proposed changes in this rider.

Rider BDP – Backup Delivery Point Capacity Rider
(Electric Tariff Sheet No. 79)

Current Rate:

BACKUP DELIVERY POINT (TRANSMISSION/DISTRIBUTION) CAPACITY

The Company will normally supply service to one premise at one standard voltage at one delivery point and through one meter to a Non-Residential Customer in accordance with the provisions of the applicable rate schedule and the Electric Service Regulations. Upon customer request, Company will make available to a Non-Residential Customer additional delivery points in accordance with the rates, terms and conditions of this Rider BDP.

NET MONTHLY BILL

1. Connection Fee

The Connection Fee applies only if an additional metering point is required and will be based on customer's most applicable rate schedule.

2. Monthly charges will be based on the unbundled distribution and/or transmission rates of the customer's most applicable rate schedule and the contracted amount of backup delivery point capacity.

3. The Customer shall also be responsible for the acceleration of costs, if any, that would not have otherwise been incurred by Company absent such request for additional delivery points. The terms of payment may be made initially or over a pre-determined term mutually agreeable to Company and Customers that shall not exceed the minimum term. In each request for service under this Rider, Company engineers will conduct a thorough review of the customer's request and the circuits affected by the request. The customer's capacity needs will be weighed against the capacity available on the circuit, anticipated load growth on the circuit, and any future construction plans that may be advanced by the request.

Proposed Rate:

There are no proposed changes in this rider.

Fuel Adjustment Clause - Rider FAC
(Electric Tariff Sheet No. 80)

Current Rate:

(1) The monthly amount computed under each of the rate schedules to which this fuel clause is applicable shall be increased or (decreased) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

$$\mathit{Fuel\,Cost\ Adjustment} = \frac{F(m)}{S(m)} - \$0.023837\ \mathit{per\ kWh}$$

Where F is the expense of fuel in the second preceding month and S is the sales in the second preceding month, as defined below:

(2) Fuel costs (F) shall be the cost of:
- (a) Fossil fuel consumed in the Company's plants plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus
- (b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus
- (c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein are such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy, and less
- (d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.
- (e) All fuel costs shall be based on a weighted-average inventory costing. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of fuel itself and necessary charges for transportation of fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licensees.
- (f) As used herein, the term "forced outages" means all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the Company

may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment.

(3) Sales (S) shall be determined in kilowatt-hours as follows:

Add:

(a) net generation
(b) purchases
(c) interchange in

Subtract:

(d) inter-system sales including economy energy and other energy sold on an economic dispatch basis
(e) total system losses

<u>**Proposed Rate**</u>:

(1) The monthly amount computed under each of the rate schedules to which this fuel clause is applicable shall be increased or (decreased) at a rate per kilowatt-hour of monthly consumption in accordance with the following formula:

$$Fuel\,Cost\,Adjustment = \frac{F(m)}{S(m)} - \$0.023837\ per\,kWh$$

Where F is the expense of fuel in the second preceding month and S is the sales in the second preceding month, as defined below:

(2) Fuel costs (F) shall be the cost of:

(a) Fossil fuel consumed in the Company's plants plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation, plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein are such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the Company to substitute for its own higher cost energy, and less

(d) The cost of fossil fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(e) The fuel-related charges and credits charged to the Company by a Regional Transmission Organization.

(f) All fuel costs shall be based on a weighted-average inventory costing. The cost of fossil fuel shall include no items other than the invoice price of fuel less any cash or other discounts. The invoice price of fuel includes the cost of fuel itself and necessary charges for transportation of fuel from the point of acquisition to the unloading point, as listed in Account 151 of the FERC Uniform System of Accounts for Public Utilities and Licensees.

(g) As used herein, the term "forced outages" means all non-scheduled losses of generation or transmission which require substitute power for a continuous period in excess of six (6) hours. Where forced outages are not as a result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the Company may, upon proper showing, with the approval of the Commission, include the fuel cost of substitute energy in the adjustment.

(3) Sales (S) shall be determined in kilowatt-hours as follows:

Add:

(a) net generation
(b) purchases
(c) interchange in

Subtract:

(d) inter-system sales including economy energy and other energy sold on an economic dispatch basis
(e) total system losses

Rider PSM – Off-System Power Sales and Emission Allowance Sales Profit Sharing Mechanism (Electric Tariff Sheet No. 82)

Current Rate:

Rate Group	**Rate (\$/ kWh)**
Rate RS, Residential Service	0.000456
Rate DS, Service at Secondary Distribution Voltage	0.000456
Rate DP, Service at Primary Distribution Voltage	0.000456
Rate DT, Time-of-Day Rate for Service at Distribution Voltage	0.000456
Rate EH, Optional Rate for Electric Space Heating	0.000456
Rate GS-FL, General Service Rate for Small Fixed Loads	0.000456
Rate SP, Seasonal Sports Service	0.000456
Rate SL, Street Lighting Service	0.000456
Rate TL, Traffic Lighting Service	0.000456
Rate UOLS, Unmetered Outdoor Lighting	0.000456
Rate OL, Outdoor Lighting Service	0.000456
Rate NSU, Street Lighting Service for Non-Standard Units	0.000456
Rate NSP, Private Outdoor Lighting Service for Non-Standard Units	0.000456
Rate SC, Street Lighting Service – Customer Owned	0.000456
Rate SE, Street Lighting Service – Overhead Equivalent	0.000456
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	0.000456
Other	0.000456

Rider PSM credits, reductions to bills, are shown as positive numbers without parentheses. Rider PSM charges, increases to bills, are shown in parentheses.

PROFIT SHARING RIDER FACTORS

The Applicable energy charges for electric service shall be increased or decreased to the nearest \$0.000001 per kWh to reflect the sharing of profits on off-system power sales and ancillary services, the net profits on sales of emission allowances and net margins on capacity transactions related to the acquisition of 100% of East Bend Unit 2.

The Company will compute its profits on off-system power sales and ancillary services, profits on emission allowance sales, and net margins on capacity transactions related to the acquisition of 100% of East Bend Unit 2 in the following manner:

$$\text{Rider PSM Factor} = ((P + A) + E + C + R)/S$$

where:

P = Eligible profits from off-system power sales for applicable month subject to sharing provisions established by the Commission in its Order in Case No. 2003-00252, dated December 5, 2003.

A = All net profits related to its provision of ancillary services in markets administered by PJM per the Commission's Order in Case No. 2008-00489, dated January 30, 2009.

The first \$1 million in annual profits from off-system sales and ancillary services will be allocated to ratepayers, with any profits in excess of \$1 million split 75:25, with ratepayers receiving 75 percent and shareholders receiving 25 percent per the Commission Order in Case No. 2010-00203, dated December 22, 2010. After December 31st of each year, the sharing mechanism will be reset for off-system power sales. Each month the sharing mechanism will be reset for the ancillary service profits.

E = All net profits on sales of emission allowances are credited to customers per the Commission's Order in Case No. 2006-00172, dated December 21, 2006.

C = Capacity revenue received from PJM associated with DP&L's share of East Bend capacity that DP&L has committed in PJM's base residual auction ("BRA") through May 31, 2018, less the cost incurred by Duke Energy Kentucky to procure sufficient capacity to meet its obligations as a Fixed Resource Requirement entity under the Reliability Assurance Agreement with PJM per the Commission's Order in Case No. 2014-00201, dated December 4, 2014.

The net of capacity revenue received from PJM and the capacity cost incurred by Duke Energy Kentucky will be allocated to ratepayers, with ratepayers receiving 75 percent and shareholders receiving 25 percent.

R = Reconciliation of prior period Rider PSM actual revenue to amount calculated for the period.

S = Current month sales in kWh used in the current month Rider FAC calculation.

Proposed Rate:

Rate Group	**Rate (\$/ kWh)**
Rate RS, Residential Service	0.000456
Rate DS, Service at Secondary Distribution Voltage	0.000456
Rate DP, Service at Primary Distribution Voltage	0.000456
Rate DT, Time-of-Day Rate for Service at Distribution Voltage	0.000456
Rate EH, Optional Rate for Electric Space Heating	0.000456
Rate GS-FL, General Service Rate for Small Fixed Loads	0.000456
Rate SP, Seasonal Sports Service	0.000456
Rate SL, Street Lighting Service	0.000456
Rate TL, Traffic Lighting Service	0.000456
Rate UOLS, Unmetered Outdoor Lighting	0.000456
Rate OL, Outdoor Lighting Service	0.000456
Rate NSU, Street Lighting Service for Non-Standard Units	0.000456
Rate NSP, Private Outdoor Lighting Service for Non-Standard Units	0.000456
Rate SC, Street Lighting Service – Customer Owned	0.000456
Rate SE, Street Lighting Service – Overhead Equivalent	0.000456
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	0.000456
Other	0.000456

Rider PSM credits, reductions to bills, are shown as positive numbers without parentheses. Rider PSM charges, increases to bills, are shown in parentheses.

PROFIT SHARING RIDER FACTORS

On a quarterly basis, the applicable energy charges for electric service shall be increased or decreased to the nearest \$0.000001 per kWh to reflect the sharing of net proceeds as outlined in the formula below.

$$\text{Rider PSM Factor} = (OSS + NF + CAP + REC + R) / S \times 0.90$$

where:

OSS = Net proceeds from off-system power sales.

NF = Net proceeds from non-fuel related Regional Transmission Organization charges and credits not recovered via other mechanisms.

CAP = Net proceeds from: PJM charges and credits as provided for in the Commission's Order in Case No. 2014-00201, dated December 4, 2014; capacity sales; capacity purchases; capacity performance credits; and capacity performance assessments.

REC = Net proceeds from the sales of renewable energy credits.

R = Reconciliation of prior period Rider PSM actual revenue to amount calculated for the period.

S = Current period sales in kWh as used in the Rider FAC calculation.

Rider GP – Duke Energy's GoGREEN Kentucky
Green Power / Carbon Offset Rider
(Electric Tariff Sheet No. 88)

Current Rate:
NET MONTHLY BILL
Customers who participate under this rider will be billed for electric service under all applicable tariffs including all applicable riders.
Green Power purchased under this rider, will be billed at the applicable Green Power rate times the number of 100 kWh blocks the customer has agreed to purchase per month.
The Green Power rate shall be $2.00 per 100 kWh block with a minimum monthly purchase of two 100 kWh blocks.
Carbon Offsets purchased under this rider, will be billed at the applicable Carbon Offset rate times the number of Carbon Offsets the customer has agreed to purchase per month.
The Carbon Offset rate shall be $4.00 per 500 lbs offset block.
Proposed Rate:
There are no proposed changes in this rider.

Rider NM – Net Metering
(Electric Tariff Sheet No. 89)

Current Rate:
AVAILABILITY
Net Metering is available to eligible customer-generators in the Company's service territory, upon request, and on a first-come, first-served basis up to a cumulative capacity of 1% of the Company's single hour peak load in Kentucky during the previous year.
Proposed Rate:
There are no proposed changes in this rider.

Bad Check Charge
(Electric Tariff Sheet No. 90)

Current Rate:
The Company may charge and collect a fee of $11.00 to cover the cost of handling an unsecured check, where a customer tenders in payment of an account a check which upon deposit by the Company is returned as unpaid by the bank for any reason.
Proposed Rate:
There are no proposed changes in this rider.

Charge for Reconnection of Service
(Electric Tariff Sheet No. 91)

Current Rate:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).
E. Where electric service was disconnected at the pole because the Company was unable to gain access to the meter, the reconnection charge shall be sixty-five dollars ($65.00). If the gas service is also reconnected the charge shall be ninety dollars ($90.00).

F. If the Company receives notice after 2:30 p.m. 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 reconnection charge for connection shall be an additional twenty-five dollars ($25.00). Customers will be notified of the additional $25.00 charge for reconnection at the meter or at the pole at the time they request same day service.

G. If a Company employee, whose original purpose was to disconnect the service, has provided the customer a means to avoid disconnection, service which otherwise would have been disconnected shall remain intact, and no reconnection charge shall be assessed. However, a collection charge of fifteen dollars ($15.00) may be assessed, but only if a Company employee actually makes a field visit to the customer's premises.

Proposed Rate:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00) for reconnections that can be accomplished remotely or seventy-five dollars ($75.00) for reconnections that cannot be accomplished remotely.

B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00) for reconnections that can be accomplished remotely or seventy-five dollars ($75.00) for reconnections that cannot be accomplished remotely.

C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) for reconnections that can be accomplished remotely or seventy-five dollars ($75.00) for reconnections that cannot be accomplished remotely, the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.

D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed eighty-eight dollars ($88.00).

E. Where electric service was disconnected at the pole because the Company was unable to gain access to the meter, the reconnection charge shall be one hundred twenty-five dollars ($125.00). If the gas service is also reconnected the charge shall be one hundred fifty dollars ($150.00).

F. If the Company receives notice after 2:30 p.m. of a customer's desire for same day reinstatement of service and if the reconnection cannot be performed during normal business hours, and the reconnection cannot be performed remotely, the after hour reconnection charge for connection shall be an additional twenty-five dollars ($25.00). Customers will be notified of the additional $25.00 charge for reconnection at the meter or at the pole at the time they request same day service.

G. If a Company employee, whose original purpose was to disconnect the service, has provided the customer a means to avoid disconnection, service which otherwise would have been disconnected shall remain intact, and no reconnection charge shall be assessed. However, a collection charge of fifty dollars ($50.00) may be assessed, but only if a Company employee actually makes a field visit to the customer's premises.

Rate for Pole Attachments of Cable Television Systems - Rate CATV
(This Schedule if Renamed as Rate DPA – Distribution Pole Attachments
(Electric Tariff Sheet No. 92)

Current Rate:

The following annual rental shall be charged for the use of each of the Company's poles:

Two-user pole: $4.60 annual rental
Three-user pole: $4.00 annual rental

Proposed Rate:

The following annual rental shall be charged for the use of each of the Company's poles:

Two-user pole: $6.35 annual rental
Three-user pole: $5.31 annual rental

Cogeneration and Small Power Production Sale and Purchase Tariff-100 kW or Less
(Electric Tariff Sheet No. 93)

Current Rate:
Rates for Purchases from qualifying facilities:
Purchase Rate shall be $0.03078/kWh for all kilowatt-hours delivered.

Proposed Rate:
Rates for Purchases from qualifying facilities:
Energy Purchase Rate shall be $0.027645/kWh for all kilowatt-hours delivered.
Capacity Purchase Rate shall be $3.90/kW-month for eligible capacity utilized by Company and approved by PJM in Company's Fixed Resource Requirements (FRR) plan.

Cogeneration and Small Power Production Sale and Pnrchase Tariff-Greater Than 100 kW
(Electric Tariff Sheet No. 94)

Current Rate:
The Purchase Rate for all kilowatt-hours delivered shall be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour of the billing month.

Proposed Rate:
The Energy Purchase Rate for all kilowatt-hours delivered shall be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour of the billing month.

Capacity Purchase Rate shall be $3.90/kW-month for eligible capacity utilized by Company and approved by PJM in Company's Fixed Resource Requirements (FRR) plan.

Local Franchise Fee
(Electric Tariff Sheet No. 95)

Current Rate:
There shall be added to the customer's bill, listed as a separate item, an amount equal to the fee now or hereafter imposed by local legislative authorities, whether by ordinance, franchise or other means, which fee is based on the gross receipts collected by the Company from the sale of electricity to customers within the boundaries of the particular legislative authority. Such amount shall be added exclusively to bills of customers receiving service within the territorial limits of the authority imposing the fee.

Where more than one such fee is imposed, each of the charges applicable to each customer shall be added to the customer's bill and listed separately.

Where the local legislative authority imposes a flat, fixed amount on the Company, the fee applied to the bills of customers receiving service within the territorial boundaries of that authority, shall be in the form of a flat dollar amount.

The amount of such fee added to the customer's bill shall be determined in accordance with the terms of the ordinance, franchise or other directive agreed to by the Company.

Proposed Rate:
There are no proposed changes to this rate.

Underground Residential Distribution Policy-Rate UDP-R
(Electric Tariff Sheet No. 96)

Current Rate:
Single Family Houses.

A. $2.15 per front foot for all primary extensions. Primary extension on private property will be charged $2.15 per linear trench foot; and
B. An additional $2.00 per linear trench foot shall be charged where extremely rocky conditions are encountered, such conditions being defined as limestone or other hard stratified material in a continuous volume of at least one cubic yard or more which cannot be removed using ordinary excavation equipment.

Multi-Family Units.

There shall be no charge except where extremely rocky conditions are encountered, then the $2.00 per linear trench foot, as stated and defined above, shall be charged.

Proposed Rate:

Single Family Houses.

A. $2.15 per front foot for all primary extensions. Primary extension on private property will be charged $2.15 per linear trench foot; and

B. An additional $2.00 per linear trench foot shall be charged where extremely rocky conditions are encountered, such conditions being defined as limestone or other hard stratified material in a continuous volume of at least one cubic yard or more which cannot be removed using ordinary excavation equipment.

Multi-Family Units.

There shall be no charge <u>except</u> where extremely rocky conditions are encountered, then the $2.00 per linear trench foot, as stated and defined above, shall be charged.

Targeted Underground for Service Improvement

Notwithstanding the above charges and upon Kentucky Public Service Commission approval, Company will waive above charges, maintain, and take ownership of customer service lines and equipment (curb, property line, or service lateral to the meter base) to and including the electric meter. This provision applies only to Company designated installations identified to improve the resiliency of service to the customer.

General Underground Distribution Policy-Rate UDP-G
(Electric Tariff Sheet No. 97)

Current Rate:

The charges shall be the difference between the Company's estimated cost to provide an underground system and the Company's estimated cost to provide an overhead system. In addition to the differential charge, the following provisions are applicable:

Single Family Houses or Multi-Family Units.

The customer may be required to provide the necessary trenching, backfilling, conduit system (if required) and transformer pads in place to Company's specifications.

Commercial and Industrial Units.

The customer shall:

a) Provide the necessary trenching and backfilling;

b) Furnish, install (concrete, if required), own and maintain all primary and/or secondary conduit system (with spares, if required) on private property meeting applicable codes and Company's specifications; and

c) Provide the transformer pad and secondary conductors.

Special Situations

In those situations where the Company considers the pad-mounted transformer installations unsuitable, the customer shall provide the vault designed to meet National Electric Code, other applicable codes, and Company specifications, the conduit to the vault area and the secondary cable to the transformer terminals. The Company shall provide the transformers, the primary vault wiring and make the secondary connection to the transformer terminals.

In large multiple cable installations, the customer shall provide the cable, provide and install the step bus mounted in the vault, and make necessary cable connections to the step bus to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the step bus.

The customer shall extend the bus duct into the vault to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the bus duct.

Proposed Rate:

The charges shall be the difference between the Company's estimated cost to provide an underground system and the Company's estimated cost to provide an overhead system. In addition to the differential charge, the following provisions are applicable:

Single Family Houses or Multi-Family Units.

The customer may be required to provide the necessary trenching, backfilling, conduit system (if required) and transformer pads in place to Company's specifications.

Commercial and Industrial Units.

The customer shall:

a) Provide the necessary trenching and backfilling;

b) Furnish, install (concrete, if required), own and maintain all primary and/or secondary conduit system (with spares, if required) on private property meeting applicable codes and Company's specifications; and

c) Provide the transformer pad and secondary conductors.

Special Situations

In those situations where the Company considers the pad-mounted transformer installations unsuitable, the customer shall provide the vault designed to meet National Electric Code, other applicable codes, and Company specifications, the conduit to the vault area and the secondary cable to the transformer terminals. The Company shall provide the transformers, the primary vault wiring and make the secondary connection to the transformer terminals.

In large multiple cable installations, the customer shall provide the cable, provide and install the step bus mounted in the vault, and make necessary cable connections to the step bus to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the step bus.

The customer shall extend the bus duct into the vault to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the bus duct.

Targeted Underground for Service Improvement

Notwithstanding the above charges and upon Kentucky Public Service Commission approval, Company will waive above charges, maintain, and take ownership of customer service lines and equipment (curb, property line, or service lateral to the meter base) to and including the electric meter. This provision applies only to Company designated installations identified to improve the resiliency of service to the customer.

Real Time Pricing Program- Rate RTP
(Electric Tariff Sheet No. 99)

Current Rate:

BASELINE CHARGE

The Baseline Charge is independent of Customer's currently monthly usage, and is designed to achieve bill neutrality with the Customer's standard offer tariff if no change in electricity usage pattern occurs (less applicable program charges). The Baseline Charge is calculated at the end of the billing period and changes each billing period to maintain bill neutrality for a Customer's CBL.

The Baseline Charge will be calculated as follows:

BC = (Standard Bill @ CBL)

Where:

BC = Baseline Charge

Standard Bill @ CBL = Customer's bill for a specific month on the applicable Rate Schedule including applicable Standard Contract Riders using the CBL to establish the applicable billing determinants.

The CBL shall be adjusted to reflect applicable metering adjustments under the Rate Schedule. All applicable riders shall be excluded from the calculation of the Baseline Charge.

PRICE QUOTES

The Company will send to Customer, within two hours after the wholesale prices are published by PJM each day, Price Quotes to be charged the next day. Such Price Quotes shall include the applicable Commodity Charge, the Energy Delivery Charge and the Ancillary Services Charge.

The Company may send more than one-day-ahead Price Quotes for weekends and holidays identified in Company's tariffs. The Company may revise these prices the day before they become effective.

The Company is not responsible for failure of Customer to receive and act upon the Price Quotes. It is Customer's responsibility to inform Company of any failure to receive the Price Quotes the day before they become effective.

COMMODITY CHARGE

The Commodity Charge is a charge for generation. The applicable hourly Commodity Charge (Credit) shall be applied on an hour by hour basis to Customer's incremental (decremental) usage from the CBL.

Charge (Credit) For Each kW Per Hour From The CBL:

For kWht above the CBLt, CCt = MVGt x LAF

For kWht below the CBLt, CCt = MVGt x 80% x LAF

Where:

LAF	=	loss adjustment factor
	=	1.0530 for Rate TS
	=	1.0800 for Rate DP
	=	1.1100 for Rate DS
MVGt	=	Market Value Of Generation As Determined By Company for hour t

The MVGt will be based on the expected market price of capacity and energy for the next day. The expected market price shall be the PJM Real-Time Total Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour.

The kW per hour incremental or decremental usage from the CBL shall be adjusted to reflect applicable metering adjustments under the standard Rate Schedule.

ENERGY DELIVER CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service .... $0.006053 per kW Per Hour
Primary Service .... $0.005540 per kW Per Hour
Transmission Service .... $0.002008 per kW Per Hour

ANCILLARY SERVICES CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Delivery.. $0.000760 per kW Per Hour
Primary Delivery.. $0.000740 per kW Per Hour
Transmission Delivery .... $0.000721 per kW Per Hour

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $183.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

Proposed Rate:

BASELINE CHARGE

The Baseline Charge is independent of Customer's currently monthly usage, and is designed to achieve bill neutrality with the Customer's standard offer tariff if no change in electricity usage pattern occurs (less applicable program charges). The Baseline Charge is calculated at the end of the billing period and changes each billing period to maintain bill neutrality for a Customer's CBL.

The Baseline Charge will be calculated as follows:

BC = (Standard Bill @ CBL)

Where:

BC = Baseline Charge

Standard Bill @ CBL = Customer's bill for a specific month on the applicable Rate Schedule including applicable Standard Contract Riders using the CBL to establish the applicable billing determinants.

The CBL shall be adjusted to reflect applicable metering adjustments under the Rate Schedule. All applicable riders shall be excluded from the calculation of the Baseline Charge.

PRICE QUOTES

The Company will send to Customer, within two hours after the wholesale prices are published by PJM each day, Price Quotes to be charged the next day. Such Price Quotes shall include the applicable Commodity Charge, the Energy Delivery Charge and the Ancillary Services Charge.

The Company may send more than one-day-ahead Price Quotes for weekends and holidays identified in Company's tariffs. The Company may revise these prices the day before they become effective.

The Company is not responsible for failure of Customer to receive and act upon the Price Quotes. It is Customer's responsibility to inform Company of any failure to receive the Price Quotes the day before they become effective.

COMMODITY CHARGE

The Commodity Charge is a charge for generation. The applicable hourly Commodity Charge (Credit) shall be applied on an hour by hour basis to Customer's incremental (decremental) usage from the CBL.

Charge (Credit) For Each kW Per Hour From The CBL:

For kWht above the CBLt, CCt = MVGt x LAF
For kWht below the CBLt, CCt = MVGt x 80% x LAF

Where:

LAF = loss adjustment factor
= 1.0530 for Rate TT
= 1.0800 for Rate DP and Rate DT
= 1.1100 for Rate DS

MVGt = Market Value Of Generation As Determined By Company for hour t

The MVGt will be based on the expected market price of capacity and energy for the next day. The expected market price shall be the PJM Day-Ahead Total Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour.

The kW per hour incremental or decremental usage from the CBL shall be adjusted to reflect applicable metering adjustments under the standard Rate Schedule.

ENERGY DELIVER CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service .... $0.015412 per kW Per Hour

Primary Service .... $0.012471 per kW Per Hour
Transmission Service .... $0.006472 per kW Per Hour

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $183.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

Meter Data Charges-Rate MDC
(This Schedule Renamed as Meter Data Charges for Enhanced Usage Data Services-Rate MDC)
(Electric Tariff Sheet No. 101)

Current Rate:

Electronic monthly interval data with graphical capability accessed via the Internet (En-Focus™) — $20.00 per month

Proposed Rate:

Electronic monthly interval data with graphical capability accessed via the Internet with (EPO™) — $20.00 per month

Duke Energy Kentucky proposes the following new rate and rider schedules: Rate LED, LED Outdoor Lighting, Rider DCI, Distribution Capital Investment Rider, Rider FTR, FERC Transmission Cost Reconciliation Rider, and Rider ESM, Environmental Surcharge Mechanism. As indicated above, the following schedules are proposed to be eliminated: Rate RTP-M (Real Time Pricing – Market Based Pricing), Rate OL (Outdoor Lighting Service), and Rate NSP (Private Outdoor Lighting for Non-Standard Units).

Rate LED – LED Outdoor Area Lighting Rate
(Electric Tariff Sheet No. 64)

Proposed Rate:

NET MONTHLY BILL

Computed in accordance with the following charges:

1. Base Rate

All kWh $0.041936 per kWh

The rate shown above includes a charge of $0.023837 per kilowatt-hour reflecting the base cost of fuel.

2. Applicable Riders

The following riders are applicable pursuant to the specific terms contained within each rider:
Sheet No. 76, Rider ESM, Environmental Surcharge Mechanism Rider
Sheet No. 80, Rider FAC, Fuel Adjustment Clause
Sheet No. 82, Rider PSM, Profit Sharing Mechanism
Sheet No. 125, Rider DCI, Distribution Capital Investment Rider
Sheet No. 126, Rider FTR, FERC Transmission Cost Reconciliation Rider

3. Monthly Maintenance, Fixture, and Pole Charges:

I. Fixtures					Per Unit Per Month	
Billing Type	Description	Initial Lumens	Lamp Wattage	Monthly kWh	Fixture	Maintenance
LF-LED-50W-SL-BK-MW	50W Standard LED-BLACK	4,521	50	17	$5.44	$4.38
LF-LED-70W-SL-BK-MW	70W Standard LED-BLACK	6,261	70	24	$5.43	$4.38
LF-LED-110W-SL-BK-MW	110W Standard LED-BLACK	9,336	110	38	$6.16	$4.38
LF-LED-150W-SL-BK-MW	150W Standard LED-BLACK	12,642	150	52	$8.16	$4.38
LF-LED-220W-SL-BK-MW	220W Standard LED-BLACK	18,641	220	76	$9.25	$5.34
LF-LED-280W-SL-BK-MW	280W Standard LED-BLACK	24,191	280	97	$11.38	$5.34
LF-LED-50W-DA-BK-MW	50W Deluxe Acorn LED-BLACK	5,147	50	17	$15.87	$4.38
LF-LED-50W-AC-BK-MW	50W Acorn LED-BLACK	5,147	50	17	$14.30	$4.38
LF-LED-50W-MB-BK-MW	50W Mini Bell LED-BLACK	4,500	50	17	$13.48	$4.38
LF-LED-70W-BE-BK-MW	70W Bell LED-BLACK	5,508	70	24	$17.17	$4.38
LF-LED-50W-TR-BK-MW	50W Traditional LED-BLACK	3,230	50	17	$10.36	$4.38
LF-LED-50W-OT-BK-MW	50W Open Traditional LED-BLACK	3,230	50	17	$10.36	$4.38
LF-LED-50W-EN-BK-MW	50W Enterprise LED-BLACK	3,880	50	17	$13.93	$4.38
LF-LED-70W-ODA-BK-MW	70W LED Open Deluxe Acorn	6,500	70	24	$15.48	$4.38
LF-LED-150W-TD-BK-MW	150W LED Teardrop	12,500	150	52	$20.78	$4.38
LF-LED-50W-TDP-BK-MW	50W LED Teardrop Pedestrian	4,500	50	17	$16.86	$4.38
220W LED SHOEBOX	220W LED Shoebox	18,500	220	76	$14.39	$5.34
LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17	$5.44	$4.38
LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24	$5.43	$4.38
LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38	$6.16	$4.38
LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52	$8.16	$4.38
LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52	$8.16	$4.38
LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76	$9.25	$5.34
LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97	$11.38	$5.34
LF-LED-50W-DA-BK-MW	LED 50W DELUXE ACORN BLACK TYPE III 4000K	5,147	50	17	$15.87	$4.38
LF-LED-70W-ODA-BK-MW	LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	6,500	70	24	$15.48	$4.38
LF-LED-50W-AC-BK-MW	LED 50W ACORN BLACK TYPE III 4000K	5,147	50	17	$14.30	$4.38
LF-LED-50W-MB-BK-MW	LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	4,500	50	17	$13.48	$4.38
LF-LED-70W-BE-BK-MW	LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	5,508	70	24	$17.17	$4.38
LF-LED-50W-TR-BK-MW	LED 50W TRADITIONAL BLACK TYPE III 4000K	3,303	50	17	$10.36	$4.38
LF-LED-50W-OT-BK-MW	LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	3,230	50	17	$10.36	$4.38
LF-LED-50W-EN-BK-MW	LED 50W ENTERPRISE BLACK TYPE III 4000K	3,880	50	17	$13.93	$4.38
LF-LED-150W-TD-BK-MW	LED 150W LARGE TEARDROP BLACK TYPE III 4000K	12,500	150	52	$20.78	$4.38
LF-LED-50W-TDP-BK-MW	LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	4,500	50	17	$16.86	$4.38
LF-LED-220W-SB-BK-MW	LED 220W SHOEBOX BLACK TYPE IV 4000K	18,500	220	76	$14.39	$5.34
LF-LED-150W-BE-BK-MW	150W Sanibel	39,000	150	52	$17.17	$4.38
LF-LED-420W-SB-BK-MW	420W LED Shoebox	39,078	420	146	$21.47	$5.34
LF-LED-50W-NB-GY-MW	50W Neighborhood	5,000	50	17	$4.43	$4.38
LF-LED-50W-NBL-GY-MW	50W Neighborhood with Lens	5,000	50	17	$4.62	$4.38

II. Poles		
Billing Type	Description	Charge per Month per Unit
LP-12-C-PT-AL-AB-TT-BK-MW	12' C-Post Top- Anchor Base-Black	$10.68
LP-25-C-DV-AL-AB-TT-BK-MW	25' C-Davit Bracket- Anchor Base-Black	$28.10
LP-25-C-BH-AL-AB-TT-BK-MW	25' C-Boston Harbor Bracket- Anchor Base-Black	$28.40
LP-12-E-AL-AB-TT-BK-MW	12' E-AL - Anchor Base-Black	$10.68
15310-40FTALEMB-OLE	35' AL-Side Mounted-Direct Buried Pole	$18.08
15320-30FTALAB-OLE	30' AL-Side Mounted-Anchor Base	$13.93
15320-35FTALAB-OLE	35' AL-Side Mounted-Anchor Base	$13.55
15320-40FTALAB-OLE	40' AL-Side Mounted-Anchor Base	$16.76
POLE-30-7	30' Class 7 Wood Pole	$6.62
POLE-35-5	35' Class 5 Wood Pole	$7.20
POLE-40-4	40' Class 4 Wood Pole	$10.84
POLE-45-4	45' Class 4 Wood Pole	$11.24
15210-20BRZSTL-OLE	20' Galleria Anchor Based Pole	$9.55
15210-30BRZSTL-OLE	30' Galleria Anchor Based Pole	$11.30
15210-35BRZSTL-OLE	35' Galleria Anchor Based Pole	$32.49
LP-12-A-AL-AB-TT-BK-MW	MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.47
LP-12-A-AL-DB-TT-BK-MW	MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black	$5.54
LP-15-A-AL-AB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.66
LP-15-A-AL-DB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$5.77
LP-20-A-AL-AB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.99
LP-20-A-AL-DB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$10.71
LP-25-A-AL-AB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$8.28
LP-25-A-AL-DB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$11.93
LP-30-A-AL-AB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$9.79
LP-30-A-AL-DB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$13.28
LP-35-A-AL-AB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$11.30
LP-35-A-AL-DB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$14.35
LP-12-B-AL-AB-TT-GN-MW	MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$7.89
LP-12-C-PT-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$10.68
LP-16-C-DV-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$14.29
LP-25-C-DV-AL-AB-TT-BK-MW	MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$28.10
LP-16-C-BH-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$11.46
LP-25-C-BH-AL-AB-TT-BK-MW	MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$28.40
LP-12-D-AL-AB-TT-GN-MW	MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$10.57
LP-12-E-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$10.68
LP-12-F-AL-AB-TT-GN-MW	MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie	$11.44
15210-20BRZSTL-OLE	MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$9.55
15210-30BRZSTL-OLE	MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$11.30
15210-35BRZSTL-OLE	MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$32.49
15310-40FTALEMB-OLE	MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$18.08
15320-30FTALAB-OLE	MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE	$13.93
15320-35FTALAB-OLE	MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE	$13.55
15320-40FTALAB-OLE	MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE	$16.76
POLE-30-7	MW-POLE-30-7	$6.62
POLE-35-5	MW-POLE-35-5	$7.20
POLE-40-4	MW-POLE-40-4	$10.84
POLE-45-4	MW-POLE-45-4	$11.24

Proposed Rider ESM – Environmental Surcharge Mechanism
(Electric Tariff Sheet No. 76)

Proposed Rate:
INITIAL FACTOR VALUES

MESF	=	0.00000%
BESF	=	0.00000%

Proposed Rider DCI – Distribution Capital Investment Rider
(Electric Tariff Sheet No. 125)

Proposed Rate:
CHARGES

The applicable energy or demand charge for electric service shall be increased or decreased to the nearest $0.000001 per kWh or $0.01 per kW to recover the revenue requirement associated with incremental distribution capital costs incurred by the Company. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Rate Group	Rate ($ / kWh)
Rate RS, Residential Service	0.000000
Rate EH, Optional Rate for Electric Space Heating	0.000000
Rate GS-FL, Optional General Service Rate for Small Fixed Loads	0.000000
Rate SP, Seasonal Sports Service	0.000000
Rate SL, Street Lighting Service	0.000000
Rate TL, Traffic Lighting Service	0.000000
Rate UOLS, Unmetered Outdoor Lighting	0.000000
Rate NSU, Street Lighting Service for Non-Standard Units	0.000000
Rate SC, Street Lighting Service – Customer Owned	0.000000
Rate SE, Street Lighting Service – Overhead Equivalent	0.000000
Rate LED, LED Outdoor Lighting Electric Service	0.000000
	($ / kW)
Rate DS, Service at Secondary Distribution Voltage	0.00
Rate DP, Service at Primary Distribution Voltage	0.00
Rate DT, Time-of-Day Rate for Service at Distribution Voltage – Primary	0.00
Rate DT, Time-of-Day Rate for Service at Distribution Voltage – Secondary	0.00

Proposed Rider FTR – FERC Transmission Cost Reconciliation Rider
(Electric Tariff Sheet No. 126)

Proposed Rate:
RIDER FTR FACTORS

Rate Group	Rate ($ / kWh)
Rate RS, Residential Service	0.000000
Rate DS, Service at Secondary Distribution Voltage	0.000000
Rate DP, Service at Primary Distribution Voltage	0.000000
Rate DT, Time-of-Day Rate for Service at Distribution Voltage	0.000000
Rate EH, Optional Rate for Electric Space Heating	0.000000
Rate GS-FL, General Service Rate for Small Fixed Loads	0.000000
Rate SP, Seasonal Sports Service	0.000000
Rate SL, Street Lighting Service	0.000000
Rate TL, Traffic Lighting Service	0.000000
Rate UOLS, Unmetered Outdoor Lighting	0.000000
Rate NSU, Street Lighting Service for Non-Standard Units	0.000000
Rate SC, Street Lighting Service – Customer Owned	0.000000
Rate SE, Street Lighting Service – Overhead Equivalent	0.000000
Rate LED, LED Street Lighting Service	0.000000
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	0.000000
Other	0.000000

In addition, Duke Energy Kentucky proposes to change text of the following tariffs: Sheet No. 24 Service Regulations Section V – Metering, Sheet No. 25 Service Regulations Section VI – Billing and Payment, Sheet No. 98 Electricity Emergency Procedures for Long-Term Fuel Shortages, and Sheet No. 100 Emergency Electric Procedures.

The foregoing rates reflect a proposed increase in electric revenues of approximately $48,646,213 or 14.96% over current total electric revenues to Duke Energy Kentucky. The estimated amount of increase per customer class is as follows:

Rate RS, Residential Service:	$22,855,269 or 17.36%;
Rate DS, Service at Distribution Voltage:	$13,198,789 or 14.30%;
Rate DT, Time-of-Day Rate for Service at Distribution Voltage:	$10,516,009 or 13.31%;
Rate EH, Optional Rate for Electric Space Heating:	$91,708 or 14.23%;
Rate SP, Seasonal Sports Service:	$3,343 or 11.41%;
Rate GS-FL, General Service Rate for Small Fixed Loads:	$86,768 or 14.38%;
Rate DP, Service at Primary Distribution Voltage:	$167,667 or 17.57%;
Rate TT, Time-of-Day Rate for Service at Transmission Voltage:	$1,416,419 or 11.12%;
Rate SL, Street Lighting Service:	$159,847 or 11.87%;
Rate TL, Traffic Lighting Service:	$8,413 or 11.75%;
Rate UOLS, Unmetered Outdoor Lighting Electric Service:	$24,006 or 11.71%;
Rate NSU, Street Lighting Service for Non-Standard Units:	$7,352 or 11.86%;
Rate SC, Street Lighting Service-Customer Owned:	$435 or 11.72%;
Rate SE, Street Lighting Service-Overhead Equivalent:	$22,650 or 11.85%;
Bad Check Charge:	$0 or 0.0%;
Charge for Reconnection of Service (electric only):	$0 or 0.0%;
Rate DPA, Rate for Distribution Pole Attachments:	$60,176 or 35.0%;
Local Franchise Fee:	$0 or 0.0%;
Rate UDP-R, Underground Residential Distribution Policy:	$0 or 0.0%;
Rate UDP-G, General Underground Distribution Policy:	$0 or 0.0%;
Rate RTP, Experimental Real Time Pricing Program: (subset of other schedules)	$87,538 or 14.87%;
Rate MDC, Meter Data Charges:	$0 or 0.0%.

The average monthly bill for each customer class to which the proposed rates will apply will increase approximately as follows:

Rate RS, Residential Service:	$15.17 or 17.1%;
Rate DS, Service at Distribution Voltage:	$114.53 or 14.3%;
Rate DT, Time-of-Day Rate for Service at Distribution Voltage:	$3,848.79 or 13.5%;
Rate EH, Optional Rate for Electric Space Heating:	$98.45 or 15.8%;
Rate SP, Seasonal Sports Service:	$18.59 or 11.7%;
Rate GS-FL, General Service Rate for Small Fixed Loads:	$8.29 or 14.9%;
Rate DP, Service at Primary Distribution Voltage:	$3,269.80 or 17.9%;
Rate TT, Time-of-Day Rate for Service at Transmission Voltage:	$7,973.24 or 10.7%;
Rate SL, Street Lighting Service:	$1.15 or 11.8%;
Rate TL, Traffic Lighting Service:	$0.09 or 12.0%;
Rate UOLS, Unmetered Outdoor Lighting Electric Service:	$0.27 or 12.0%;
Rate OL-E, Outdoor Lighting Equipment Installation:	$0 or 0.0%;
Rate NSU, Street Lighting Service for Non-Standard Units:	$0.88 or 11.9%;
Rate SC, Street Lighting Service-Customer Owned:	$0.21 or 11.7%;
Rate SE, Street Lighting Service-Overhead Equivalent:	$0.92 or 11.9%;
Bad Check Charge:	$0 or 0.0%;
Charge for Reconnection of Service (electric only):	$0 or 0.0%;
Rate DPA, Rate for Distribution Pole Attachments:	$1.53 or 35.0%;
Rate RTP, Experimental Real Time Pricing Program:	$1,887.21 or 15.6%;
Rate MDC, Meter Data Charges:	$0 or 0.0%.

The rates contained in this notice are the rates proposed by Duke Energy Kentucky; however, the Kentucky Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such action may result in rates for consumers other than the rates in this notice.

Any corporation, association, body politic or person with a substantial interest in the matter may, by written request within thirty (30) days after publication of this notice of the proposed rate changes, request leave to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown. Such motion shall be submitted to the Kentucky Public Service Commission, P. O. Box 615, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, and shall set forth the grounds for the request including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication the Commission may take final action on the application.

Intervenors may obtain copies of the application and other filings made by the Company by contacting Ms. Minna Rolfes-Adkins at 139 East Fourth Street, Cincinnati, Ohio 45202 or by telephone at (513) 287-4356. A copy of the application and other filings made by the Company is available for public inspection through the Commission's website at http://psc.ky.gov, at the Commission's office at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 am. To 4:30 p.m., and at the following Company offices: 4580 Olympic Boulevard, Erlanger, Kentucky 41018. Comments regarding the application may be submitted to the Public Service Commission through its website, or by mail at the following Commission address.

For further information contact:

PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY
P. O. BOX 615
211 SOWER BOULEVARD
FRANKFORT, KENTUCKY 40602-0615
(502) 564-3940

DUKE ENERGY KENTUCKY
4580 OLYMPIC BOULEVARD
ERLANGER, KENTUCKY 41018
(513) 287-4315

Duke Energy Kentucky
Customer Charge Analysis
Attachment BLS-2

Line	Rate	(A) Cost of Service Study Customer Component	(B) Test Period Number of Bills	(C) = (A)/(B) COSS Calculated Customer Charge
1	RS	$ 17,221,037	1,534,899	$ 11.22
2	DS*	$ 3,977,527	158,808	$ 25.05
3	DP	$ 14,254	120	$ 118.78
4	DT Secondary**	$ 238,764	596	$ 400.61
5	DT Primary	$ 68,850	148	$ 465.20
6	TT***	$ 40,724	156	$ 261.05

*Note: Rate DS is a combined single and three phase value with the resulting customer charge representing an average value. Value is reduced for RTP

Duke Energy Kentucky
Residential Customer Charge Comparison
Attachment BLS-3

Line	Rate	(A) COSS Calculated Customer Charge	(B) Current Customer Charge	(C) Proposed Customer Charge
1	Duke Energy Kentucky - RS	$ 11.22	$ 4.50	$ 11.22
2	Kentucky Power*		$ 11.00	
3	Louisville Gas & Electric*		$ 10.75	
4	Kentucky Utilities*		$ 12.25	

*Note: Other KY IOU Residential Customer Charges from respective websites on 7/10/17.

Duke Energy Kentucky
Witness B.L. Sailers
Case No. 2017-00321
CATV Pole Attachment Formula - Adminstrative Case No. 251
For Use of Electric Utility Poles
BASED UPON 2016 FERC FORM 1 DATA

	FCC Pole Attachment Rate Formula	Amount 35'	40'	45'	Two User	Three User
1	Gross Pole Investment	$4,230,529	$14,085,193	$14,193,838	$18,315,722	$28,279,031
2	Pole Depreciation Reserve	$2,118,720	$7,054,102	$7,108,513	$9,172,822	$14,162,615
3	Appurtenance Factor	$389,548	$1,296,966	$1,306,970	$1,686,514	$2,603,936
4	Accumulated Deferred Taxes (Poles)	($485,175)	($1,615,350)	($1,627,809)	($2,100,525)	($3,243,159)
5	Net Pole Investment	$1,626,634	$5,415,741	$5,457,516	$7,042,375	$10,873,257
6	Number of Poles	6,724	16,887	10,155	23,611	27,042
7	Net Investment Per Bare Pole	$183.98	$243.90	$408.72	$226.84	$305.80
8	Pole Maintenance					
	A. Maintenance of Overhead Lines	$5,716,388	$5,716,388	$5,716,388	$5,716,388	$5,716,388
	B. Total Investment in Poles, Conductors, Services	$192,957,228	$192,957,228	$192,957,228	$192,957,228	$192,957,228
	C. Depreciation Reserve	$75,194,597	$75,194,597	$75,194,597	$75,194,597	$75,194,597
	D. Accumulated Deferred Taxes	($22,131,399)	($22,131,399)	($22,131,399)	($22,131,399)	($22,131,399)
	E. Total Investment in Poles - Net	$139,894,030	$139,894,030	$139,894,030	$139,894,030	$139,894,030
	F. Pole Maintenance Ratio	4.09%	4.09%	4.09%	4.09%	4.09%
9	Depreciation	4.28%	4.28%	4.28%	4.28%	4.28%
10	Administration	2.13%	2.13%	2.13%	2.13%	2.13%
11	Taxes (Normalized)	4.00%	4.00%	4.00%	4.00%	4.00%
12	Rate of Return	8.36%	8.36%	8.36%	8.36%	8.36%
13	Total Carrying Charge	22.85%	22.85%	22.85%	22.85%	22.85%
14	Allocated Space				12.24%	7.59%
15	Maximum Rate Per Attachment				$6.35	$5.31

Duke Energy Kentucky
Calculation of Reconnection Fees

Base Labor		$33.27	
Unproductive	30.0%	$9.98	Loads on Base - direct labor
Incentives	3.0%	$1.30	Loads on Base plus Unprod
Subtotal		$11.28	
Fringes	22.4%		
Payroll Tax	7.7%		
Subtotal	30.1%	13.41	Loads on Base plus Unprod plus Incentive
Fleet	22.2%	7.39	Loads on Base - direct labor
Loaded Labor w/ Fleet		$65.35	
Indirects	44.8%	$29.28	Load on Loaded Labor
Site Supervision			
Engineering	19.1%	$12.48	Load on Loaded Labor
Setup	18.0%	$11.76	Load on Loaded Labor
Total Cost Per Hour		$118.87	

[redacted]

	Approximate Hours	Cost		Propose
Remote Reconnect (AMI)	0.25	$29.72		$25.00
Non-Remote Reconnection	0.75	$89.15		$75.00
Pole Reconnection	1.10	$130.75	Single person crew	$125.00
Non-Remote After Hours	0.85	$101.04		$100.00
Pole Reconnection After Hours	1.70	$202.07	Two person crew	$150.00
Collection Charge (Field Visit)	0.50	$59.43		$50.00

Direct Testimony of
Jeffrey R. Setser

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	))))))))))	Case No. 2017-000321

DIRECT TESTIMONY OF

JEFFREY R. SETSER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey R. Setser, and my business address is 550 South Tyron 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 of Allocations and Reporting. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I graduated with a Bachelor of Science Degree in Industrial Engineering from North Carolina State University and a Master's Degree in Business Administration from Queens University in Charlotte. I am a Certified Public Accountant in North Carolina.

I joined the company in 1984 in the Nuclear Production Department's corporate office as an Assistant Engineer, primarily focusing on nuclear process improvement activities. In 1986, I moved to Catawba Nuclear Station where I was promoted to Associate Engineer and responsible for nuclear outage scheduling and training. In 1989, I was promoted to Nuclear Production Engineer responsible for the supervision and scheduling of all online plant activities, and the planning for Nuclear Station Modifications. In 1992, I joined the Catawba Nuclear Station Business group as a Strategic Business Consultant responsible for site financial reporting, budgeting, performance measures, accounting support, economic analysis and business case justifications. In 1996, I assumed the role of Catawba Nuclear Station Manager of Financial Analysis supervising the development of business plans, budgets and measures and the reporting on site financial results. In 2000, I moved back to the corporate offices as an Accounting Manager overseeing the utilities Accounting Controls and Application Support Department, which included the management of department level allocation processes. In 2002, I joined the Corporate Controllers department as an Accounting Manager where I held numerous roles, including overseeing the accounting and reporting for stock based compensation, employee and executive benefits, managing the intercompany billing process and service level agreements for joint venture and foreign entities, accounting for Canadian entities related to corporate and captive insurance, reporting and analysis on the Duke Energy Other business segment, and supervising the allocation of benefits and corporate costs. In 2006, I assumed my current role as Director of Allocations and Reporting in the Corporate Controller's department.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS DIRECTOR OF ALLOCATIONS AND REPORTING.

A. I am responsible for various accounting activities, including the cost allocation processes for service company costs utilized for Duke Energy and its affiliates, including allocations to Duke Energy Kentucky.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE KENTUCKY PUBLIC SERVICE COMMISSION?

A. No.

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

A. My testimony in this proceeding addresses the various cost assignment processes utilized by Duke Energy Kentucky and its affiliates, including its service company, DEBS, which as an ordinary course of business provide services among each other.

I discuss the primary service agreements used by Duke Energy Kentucky to enable the sharing of expertise and personnel between and among the Duke Energy family of companies and to assign costs for such services. These service agreements include the following: (1) the Service Company Utility Service Agreement (DEBS Service Agreement); (2) the Operating Companies Service Agreement (Operating Company Service Agreement); (3) the Operating Company/Non-Utility Companies Service Agreements (Cost-Based Non-Utility Service Agreement); (4) the Asymmetrically-Priced Duke Energy Kentucky, Inc., Non-Utility Companies Service Agreement (Asymmetric Non-Utility Agreement); and (5) the Intercompany Asset Transfer Agreement (Asset Transfer Agreement). In my testimony, I briefly describe the history of these agreements as well as the Commission's approval thereof. I also describe the processes to be used to assign costs to the various parties under those agreements as well as the nature and types of cost assignment that Duke Energy Kentucky experiences as a combination gas and electric utility and wholly owned subsidiary of Duke Energy Ohio, Inc., (Duke Energy Ohio). I sponsor certain information that I supplied to Duke Energy Kentucky witness, Robert "Beau" Pratt for his use in developing the forecasted financial data. Finally, I also sponsor the information contained in Filing Requirement (FR) 16(7)(u).

II. THE SERVICE AGREEMENTS

A. OVERVIEW OF THE MAJOR SERVICE AGREEMENTS

Q. DO ALL CHARGES FOR DUKE ENERGY KENTUCKY ORIGINATE ON DUKE ENERGY KENTUCKY'S BOOKS?

A. No. Charges can originate either on Duke Energy Kentucky's books for its own operations or can originate from its parent company, Duke Energy Ohio, and/or other affiliated companies pursuant to several Commission-approved affiliate service agreements. These services enable Duke Energy Kentucky to provide safe and reliable utility service to its Kentucky customers at a reasonable price.

Q. PLEASE BRIEFLY DESCRIBE THE VARIOUS SERVICE AGREEMENTS THAT ENABLE DUKE ENERGY KENTUCKY TO PROVIDE SAFE, RELIABLE, AND REASONABLE SERVICE TO ITS KENTUCKY CUSTOMERS.

A. Duke Energy Kentucky has several service agreements in place that allow the Company to provide services to, or receive services from the Duke Energy family of companies that are incidental or necessary to the provision of utility service. These agreements provide for the standard procedures and defined accounting processes for cost assignment that allow these services to occur on an equitably-priced basis among all parties.

I have attached the five major service agreements to my testimony, all of which were effective when the Company commenced these proceedings and submitted its pre-filing notice. Attachment JRS-1 is the DEBS Service Agreement that governs the provision of various services and the associated cost allocations to Duke Energy Kentucky for the services DEBS provides. DEBS is a Federal Energy Regulatory Commission (FERC) authorized service company that provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy.

Attachment JRS-2 is the Operating Company Service Agreement that governs services performed between or among Duke Energy's regulated utility operating companies and the cost allocations or assignments for providing and receiving those services.

Attachment JRS-3 and JRS-4 are the two Utility/Non-Utility Companies Service Agreements, which governs the services performed and cost allocations between Duke Energy Kentucky and its non-utility affiliates.

Finally, Attachment JRS-5 is the Asset Transfer Agreement that allows for the "at cost" transfer of assets by and between Duke Energy Kentucky and its regulated utility affiliates.

Q. HAS DUKE ENERGY KENTUCKY HISTORICALLY RELIED UPON SERVICE AGREEMENTS TO SERVE ITS KENTUCKY CUSTOMERS?

A. Yes. These service agreements allow Duke Energy Kentucky, and in turn, its customers to have access to equipment and personnel that are common to utility operations and share in those costs between multiple businesses as opposed to having to maintain separate pools of personnel. The use of service agreements has helped Duke Energy Kentucky, and its regulated utility affiliates, to manage staffing levels and costs through the sharing of common business functions and to have ready access to experienced and expertly trained personnel to manage its business and various utility functions. Absent the ability to share these resources, Duke Energy Kentucky would have to maintain its own independent organizations and systems, as well as cost responsibility, for various operations including, but not limited to engineering, construction, operations and maintenance, installation services, equipment testing, generation technical support, environmental health and safety and procurement services, not to mention, accounting, human resources, legal, and other necessary business functions.

Q. WHY IS THAT?

A. Duke Energy Kentucky itself is relatively small in size. It has approximately 140,600 electric and 98,200 gas customers. Because of its size, the relationship between Duke Energy Kentucky and its parent, Duke Energy Ohio, as well as its affiliated regulated and service companies have been instrumental in allowing Duke Energy Kentucky to provide service to its Kentucky customers at a reasonable price. The Company has benefitted from the economies of scale that occur with being part of a larger corporate family that are not present as a stand-alone entity. By sharing resources and personnel, Duke Energy Kentucky is able to function as a lean utility without having to invest in its own full-time corporate personnel and resources that are otherwise able to be shared among a family of companies.

Throughout its history, Duke Energy Kentucky has benefitted from the relationships with the families of companies of which it has been a member. Since 1945, Duke Energy Kentucky (f/k/a The Union Light Heat & Power Company) has been a wholly owned subsidiary of Duke Energy Ohio (f/k/a/ The Cincinnati Gas & Electric Company [CG&E]). The respective service territories of the two utilities are contiguous and interconnected. The two companies have operated in symmetry in terms of personnel and facilities and have shared in costs, equipment and personnel, for more than seventy years.

With the creation of Cinergy Corp (Cinergy) in the mid 1990's, by way of the merger of the CG&E with Public Service Indiana, to the merger between Cinergy and Duke Power in 2006, followed by the merger of Duke Energy and Progress Energy (Progress) in 2012, to the most recent merger between Duke Energy and Piedmont Natural Gas Company (Piedmont), Duke Energy Kentucky has benefitted from the pool of expert personnel resources and access to equipment and expertise from its sister companies. Duke Energy Kentucky has been able to share in common business functions rather than maintain its own dedicated and thus duplicative functions. These shared functions include but are not limited to, executive and management personnel, human resources, accounting, tax, legal services, and engineering. Through the Utility Service Agreement, Duke Energy Kentucky has also been able to take advantage of the key personnel employed by its sister utilities, allowing the Company to take advantage of the economies of scale and best practices that exist with an organization the size of Duke Energy through shared expertise and resources.

Q. HAVE THERE BEEN ANY CHANGES TO THESE AGREEMENTS SINCE THE TIME OF THE COMPANY'S LAST BASE ELECTRIC RATE CASE IN 2006 AND ITS LAST NATURAL GAS RATE CASE IN 2009?

A. Yes. There are regular and normal updates that occur to these agreements to reflect changes in the Duke Energy corporate structure. Companies are routinely dissolved and are eliminated from some of the agreements. Duke Energy Kentucky routinely files updates to these agreements when there are material changes and also as part of its annual reporting. These agreements are included in the Appendix to the Company's Cost Allocation Manual that is routinely submitted to the Commission annually in March.

Since the time of the Company's last electric rate case filing in 2006 and last natural gas base rate case in 2009, there have been changes to these agreements primarily to reflect the addition or removal of the parties (affiliated companies) to these agreements. For example, during 2012, immediately following the completion of the merger between Duke Energy and Progress, Progress Energy Service Company (PESC) was a party to the DEBS Service Agreement and provided services to Duke Energy Kentucky. Since that time, PESC was dissolved and removed from that agreement. The majority of PESC employees are now DEBS employees and their work performed for Duke Energy Kentucky is included as part of the total DEBS allocations that the Company receives. Similarly, in 2016, Duke Energy Corp completed its merger with Piedmont. As a result of this merger, the Piedmont utility companies have been added as parties to the relevant agreements. As result of these and other additions and deletions to the service agreement participants, allocations (direct and indirect) between and among the parties have also changed over the years.

Q. PLEASE BRIEFLY DESCRIBE THE DEBS AGREEMENT.

A. This agreement permits DEBS to provide services that are corporate or general utility in nature and are used by various business units, including Duke Energy Kentucky. In general, the services provided by the service companies include, but are not limited to the following:

- Information Systems; Meters; Transportation;
- System Maintenance;
- Marketing and Customer Relations;
- Transmission and Distribution Engineering and Construction;
- Power and Gas Engineering and Construction;
- Human Resources;
- Supply Chain;
- Facilities;
- Accounting;
- Power and Gas Planning and Operations;
- Public Affairs;
- Legal;
- Rates;
- Finance;
- Rights of Way;
- Internal Auditing;
- Environmental, Health and Safety;
- Fuels;
- Investor Relations;
- Planning; and
- Executive.

By the terms of the DEBS Service Agreement, compensation for any service rendered by the DEBS to its utility affiliates is the fully embedded cost thereof (*i.e.*, the sum of: (i) direct costs; (ii) indirect costs; and (iii) costs of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code. Each client company is required to reasonably cooperate with each respective service provider to record billings and payments in their common accounting systems. The affiliate companies receiving services from DEBS are referred to as "Client Companies."

Q. PLEASE BRIEFLY DESCRIBE THE OPERATING COMPANY SERVICE AGREEMENT AND ITS HISTORY.

A. Like the DEBS Service Agreement, the Operating Company Service Agreement has been in place in some form for decades. Under this agreement, Duke Energy Kentucky and its utility affiliates, Duke Energy Carolinas LLC., (Duke Energy Carolinas), Duke Energy Ohio, Duke Energy Indiana, LLC., (Duke Energy Indiana), Duke Energy Progress, LLC., Duke Energy Florida, LLC., and Piedmont, are permitted to provide and receive services to and from each other in the normal course of conducting business at the providing company's fully embedded cost. This agreement was most recently approved by the Commission on June 1, 2017, in Case No 2016-00312 reflecting the addition of Piedmont. Prior to that, the agreement was reviewed and approved by the Commission on August 2, 2011, in Case No 2011-00124, as part of the merger of Duke Energy Corporation and Progress. A copy of this agreement included as Attachment JRS-2. The services which may be provided between affiliate operating companies may include, but are not limited to the following:

- Engineering and Construction;
- Operations and Maintenance;
- Installation Services;
- Equipment Testing;
- Generation Technical Support;
- Environmental, Health and Safety;
- Customer Operations; and
- Procurement Services.

By the terms of the Operating Company Service Agreement, compensation for any service rendered between utility affiliates is the fully embedded cost thereof (*i.e.*, the sum of: (i) direct costs; (ii) indirect costs; and (iii) costs of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code. Each client company is required to reasonably cooperate with each respective service provider to record billings and payments in their common accounting systems.

Q. PLEASE DESCRIBE THE TWO NON-UTILITY SERVICE AGREEMENTS

A. Duke Energy Kentucky is a party to two service agreements that identify services and cost allocations between the Company and its non-utility affiliates. The distinction between these two agreements are due to timing in relation to FERC Orders and the types of pricing for the provision of services allowed therein.

Under the Cost-Based Non-Utility Service Agreement, Duke Energy Kentucky and certain of its non-utility affiliates are authorized to provide certain services to one another, priced at the providing company's fully embedded cost. A copy of this agreement is included in Attachment JRS-3. This agreement was last approved by the Commission on November 27, 2005, in Case No 2005-00228, as part of the merger of Duke Energy Corporation and Cinergy Corp. The permitted services provided by Duke Energy Kentucky to certain of its non-utility affiliates may include, but are not limited to the following:

- Engineering and Construction;
- Operations and Maintenance;
- Installation Services;
- Equipment testing;
- Generation Technical Support;
- Environmental, Health and Safety; and
- Procurement Services.

The types of services that may be provided by certain non-utility affiliates to Duke Energy Kentucky, include, but are not limited to, the following:

- Information Technology Services;
- Monitoring;
- Surveying;
- Inspecting;
- Constructing;
- Locating and Marking of Overhead and Underground Utility Facilities;
- Meter Reading;
- Materials Management;
- Vegetation Management; and
- Marketing and Customer Relations.

By the terms of the Cost-Based Non-Utility Agreement, requests for services will be made in writing, in substantially the same form as set forth in "Exhibit A" of the Agreement. Compensation for any service rendered between Duke Energy Kentucky and its non-utility affiliates are the fully embedded cost thereof (*i.e.*, the sum of: (i) direct costs; (ii) indirect costs; and (iii) costs of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code. The non-utility affiliates that are parties to this agreement are limited to those that existed prior to FERC's February 2008 Order 707 (Order 707) that expanded FERC's asymmetrical pricing rules to include transfers of non-power goods and services between a franchised utility and its non-utility affiliates.

Non-utility companies that became affiliates of Duke Energy Kentucky after Order 707 are subject to a different service agreement, the Asymmetric Non-Utility Service Agreement, included as Attachment JRS-4. The Asymmetric Non-

Utility Service Agreement was created in response to Order 707. The non-utility affiliates who are parties to this agreement are subject to the asymmetric pricing requirements of FERC, which is also consistent with Kentucky's own default affiliate pricing requirements. Duke Energy Kentucky provides (non-tariffed) goods or services to a Party to this agreement at the greater of cost or market, but pays the lesser of cost or market for any goods or services received under this agreement.

Q. CAN YOU PLEASE EXPLAIN WHAT CHANGED WITH THE FERC 707 ORDER?

A. It is my understanding that prior to Order 707, FERC's asymmetrical pricing rules only applied to transfers of non-power goods and services between franchised utilities and nonregulated utility affiliates. However, following the Order 707 ruling, FERC's asymmetric pricing requirements were extended to all transactions between utilities and their non-utility affiliates. This asymmetric pricing requirement excluded services provided by service companies or services between and among regulated utility affiliates. The Order 707 ruling also provided a grandfathering exception to the asymmetric pricing for pre-existing service agreements between regulated utilities and their non-regulated non-utility affiliates, as well as, state affiliate pricing rules that are stricter than the FERC's pricing restrictions.

In short, the Asymmetric Non-Utility Agreement was entered into in response to FERC Order 707 and includes new affiliates that were created after the effective date of Order 707 and that are not grandfathered as parties under the

Cost-Based Non-Utility Service Agreement. The Cost-Based Non-Utility Agreement remains unchanged since the issuance of Order 707, except to reflect the dissolution of non-utility companies that were at one time a party. No new companies have been added to that Cost-Based Non-Utility Agreement since the Order 707.

Q. PLEASE EXPLAIN HOW SERVICES BETWEEN DUKE ENERGY KENTUCKY AND ITS AFFILIATES THAT ARE NOT COVERED BY THE AFOREMENTED SERVICE AGREEMENTS ARE PRICED?

A. Non-covered services, as well as non-utility affiliates that are not a party to the Cost-based Non-Utility Service Agreement, must follow Kentucky's stricter asymmetric pricing for any transaction with Duke Energy Kentucky unless Commission approval and a waiver is first obtained.

Q. PLEASE EXPLAIN AND DESCRIBE THE ASSET TRANSFER AGREEMENT.

A. This agreement permits the transfer of assets between and among Duke Energy Kentucky and its regulated utility affiliates, excluding commodities, at the transferring company's fully–allocated cost, subject to certain limitations. This agreement was most recently approved by the Commission on June 1, 2017, in Case No. 2016-00312, to reflect the addition of Piedmont. Prior to that, the Commission approved the agreement on August 2, 2011, in Case No. 2011-00124, as part of the merger of Duke Energy Progress Energy. A copy of this agreement is included as Attachment JRS-5.

Q. ARE THERE ANY LIMITATIONS APPLICABLE TO TRANSACTIONS INVOLVING DUKE ENERGY KENTUCKY UNDER THE ASSET TRANSFER AGREEMENT?

A. The Commission approved this agreement under several conditions, including that:

- Duke Energy Kentucky agree that it would continue to seek Commission approval under KRS 278.218 over all transactions involving Duke Energy Kentucky assets that have an original book value of over $1,000,000 and that are to be transferred for reasons other than obsolescence or if the parts are to be used to continue to provide service to the utility customers;
- Duke Energy Kentucky agree to abide by the KRS 278.218 approval threshold for transfers involving its natural gas assets; and
- Duke Energy Kentucky maintains a list of all transactions under the Intercompany Asset Transfer Agreement in its Cost Allocation Manual (CAM).

Q. DOES DUKE ENERGY KENTUCKY MAINTAIN THE LIST OF TRANSACTIONS IN ITS CAM?

A. Yes. The Company submits those transactions to the Commission annually each March as part of an annual CAM update.

III. COST ALLOCATIONS

A. OVERVIEW OF COST ALLOCATIONS

Q. PLEASE DESCRIBE WHAT IS MEANT BY THE TERM "COST."

A. "Cost," as used in the Utility Service Agreement and Non-Utility Service Agreement, means fully embedded cost, which is the sum of: (1) direct costs; (2) indirect costs; and (3) cost of capital. Direct costs include labor, material and other expenses incurred specifically for a particular service and any associated loadings. Indirect costs include labor, material and other expenses, and any associated loadings that cannot be directly identified with any particular service. Indirect costs include, but are not limited to, overhead costs, administrative support costs, and taxes. Cost of capital represents financing costs, including, but not limited to, interest on debt and a fair return on equity to shareholders.

Q. PLEASE DESCRIBE THE COST ALLOCATIONS THAT AFFECT DUKE ENERGY KENTUCKY AND ITS AFFILIATES?

A. In general, there are four primary categories of cost allocations that affect Duke Energy Kentucky and its affiliates: (1) cost allocations from DEBS; (2) cost allocations between Duke Energy Kentucky and Duke Energy Ohio for common costs shared by Duke Energy Ohio and Duke Energy Kentucky; (3) cost allocations for goods and services provided between and among Duke Energy Kentucky and its sister regulated utilities; and (4) administrative and general (A&G) cost allocations between its gas and electric operations for both capital and expense accounts.

Duke Energy Kentucky also provides various services and goods to and receives various services and goods from its regulated and nonregulated affiliates as set forth in various service agreements I previously described.

Q. WHAT ARE "LOADINGS"?

A. "Loadings" represent costs that are incurred and aggregated in "cost pools", which are then subsequently "loaded" out to specific entities and projects by attaching an additional charge (loading rate) to the associated direct cost. Duke Energy's loadings include fringe benefits (*e.g.,* medical, dental, pension, postretirement), indirect labor (*e.g.,* vacation, holiday, sick-time), stores, freight and handling (*e.g.,* material management labor, freight), transportation (*e.g.,* vehicle leases, fuel, oil), and payroll taxes (*e.g.,* Federal Insurance Contributions Act (FICA) taxes, and state and federal unemployment taxes). Loading rates are determined through annual studies of both actual and budgeted information and are calculated by dividing the anticipated component costs by anticipated labor cost, material issues, or vehicle utilization, as applicable.

B. COST ALLOCATIONS UNDER THE SERVICE AGREEMENTS

Q. PLEASE DESCRIBE HOW COSTS INCURRED BY DEBS ARE ACCOUNTED FOR UNDER THE SERVICE AGREEMENTS.

A. DEBS maintains an accounting system in which all of its costs are accumulated. These costs are charged to the appropriate Client companies monthly, using one of the three approved methods of assignment.

Q. WHAT ARE THE APPROVED METHODS OF ASSIGNMENT?

A. The approved methods of assignment are: (1) directly assignable; (2) distributable; and (3) allocable.

Q. PLEASE DESCRIBE EACH METHOD OF ASSIGNMENT.

A. The directly assignable basis of cost assignment is utilized to directly charge costs for services specifically performed for a single Client company. The distributable cost assignment method is used to assign costs for services rendered specifically for two or more Client companies. The allocable method of assignment is used to allocate costs for services of a general nature, which are applicable to all Client companies or to a class or classes of Client companies.

Q. WHAT TYPES OF EXPENDITURES ARE DIRECTLY ASSIGNED FROM DEBS TO DUKE ENERGY KENTUCKY?

A. DEBS employees who work on a project specifically for Duke Energy Kentucky charge their labor and expenses directly to Duke Energy Kentucky. For example, the legal services function will charge Duke Energy Kentucky directly for work performed specifically for Duke Energy Kentucky. This is determined by the number of hours spent on jurisdictional activities.

Q. PLEASE EXPLAIN THE ALLOCABLE CHARGES FROM DEBS TO DUKE ENERGY KENTUCKY.

A. Allocable charges to Duke Energy Kentucky are for a portion of expenditures originating on DEBS' books that are applicable to Duke Energy Kentucky and one or more other Client Companies, but which are not directly assignable to Duke Energy Kentucky. These charges are allocated to Duke Energy Kentucky based on allocation ratios set forth in Appendix A of the DEBS Service Agreement. For example, costs related to Investor Relations activities are applicable to all Duke Energy affiliates but cannot be direct charged to any one affiliate. Those costs are allocated to all affiliates using the allocation factor described for the Investor Relations Function in Appendix A of the DEBS Service Agreement.

Q. WHAT ARE THE ALLOCATION METHODS SPECIFIED IN APPENDIX A OF THE DEBS SERVICE AGREEMENT?

A. Twenty (20) allocation ratios are specified in the Utility Service Agreement. These ratios are the: (1) Sales Ratio; (2) Electric Peak Load Ratio; (3) Number of Customers Ratio; (4) Number of Employees Ratio; (5) Construction-Expenditures Ratio; (6) Miles of Electric Distribution Lines Ratio; (7) Circuit Miles of Electric Transmission Lines Ratio; (8) Millions of Instructions Per Second Ratio; (9) Revenues Ratio; (10) Inventory Ratio; (11) Procurement Spending Ratio; (12) Square Footage Ratio; (13) Gross Margin Ratio; (14) Labor Dollars Ratio; (15) Number of Personal Computer Work Stations Ratio; (16) Number of Information Systems Servers Ratio; (17) Total Property, Plant and Equipment Ratio; (18) Generating Unit MW Capability Ratio; (19) Number of Meters Ratio; and (20) O&M Expenditures Ratio.

Q. WHAT WAS THE RATIONALE BEHIND THE SELECTION OF THESE RATIOS?

A. Consistent with traditional cost causation principles, the ratios represent "cost drivers" for a particular function (*i.e.*, those factors which are the greatest contributors to costs). For example, costs related to human resources are allocated based on the Number of Employees Ratio. Costs related to support of personal computers are allocated based on the Number of Personal Computer Workstations Ratio. Costs related to meter reading and to customer billing and payment processing in the Marketing and Customer Relations Function, are allocated based on the Number of Customers Ratio. For some Functions, costs of a general nature are allocated based on a weighted-average of more than one ratio. The DEBS Service Agreement describes how the weighted-average ratios are calculated.

Q. UNDER WHAT CIRCUMSTANCES ARE THE ALLOCATION RATIOS SET FORTH IN APPENDIX A OF THE DEBS SERVICE AGREEMENT USED TO DETERMINE CHARGES TO DUKE ENERGY KENTUCKY?

A. The allocation ratios provided in Appendix A of the DEBS Service Agreement are used to assign charges to Client Companies, including Duke Energy Kentucky, for activities that cannot be charged directly. For example, costs associated with the human resources function are allocated to the Client Companies, including Duke Energy Kentucky, using the Number of Employees Ratio as provided in the DEBS Service Agreement.

Q. WHAT PROCESSES DO DEBS EMPLOYEES FOLLOW IN ALLOCATING THEIR TIME AND EXPENSES?

A. All source documents (*e.g.*, time records, expense accounts, and journal entries) applicable to DEBS require a special input code, "Operating Unit" (OU), to be used. The initiating department determines the appropriate OU for each transaction. The specific OU indicates whether the cost should be assigned directly, distributed, or allocated, and it also determines the appropriate percentage allocation to be used. Using the OU, the accounting system will process each transaction and assign the appropriate costs to each respective Client Company. For the allocable OUs, the percentage allocated to each Client Company is determined periodically, at a minimum on an annual basis, by way of a cost study.

Q. PLEASE DESCRIBE FURTHER THE COST STUDY USED TO DETERMINE THE OU ALLOCATION PERCENTAGES.

A. On a periodic basis, but no less than annually, DEBS conducts a cost study, applying the applicable data to the allocation ratios described in Appendix A to the DEBS Service Agreement. From these cost studies, DEBS updates the allocation percentages of each allocable OU to reflect the current underlying foundation of the allocation ratios. For example, annually, the OU based on the number of employees, which is primarily utilized by the human resources function within DEBS, is updated to reflect the number of employees of each of DEBS' affiliate companies.

Q. WERE ANY AUDITS CONDUCTED OF DEBS?

A. Yes. Duke Energy has conducted an internal audit of DEBS cost allocations on a regular basis. In addition, Duke Energy Kentucky has agreed to bi-annual audits of its affiliate transactions as part of various merger commitments. The most recent completed audit was submitted to the Commission on June 20, 2017. To date, these audit reports support that Duke Energy has adequate processes in place for allocating costs and have not found any material or significant deficiencies.

C. COST ALLOCATIONS FOR COMMON COSTS SHARED BY DUKE ENERGY KENTUCKY AND DUKE ENERGY OHIO

Q. PLEASE EXPLAIN THE DIRECT CHARGES FROM DUKE ENERGY OHIO TO DUKE ENERGY KENTUCKY?

A. Direct charges from Duke Energy Ohio to Duke Energy Kentucky are for costs such as employee labor, employee expenses, and inventory (material) transactions which are specifically incurred for Duke Energy Kentucky's gas and/or electric operations.

Q. WHAT TYPES OF CHARGES ARE ALLOCATED TO DUKE ENERGY KENTUCKY FROM DUKE ENERGY OHIO?

A. Charges allocated to Duke Energy Kentucky from Duke Energy Ohio represent a portion of costs originating on Duke Energy Ohio's books that apply to gas and/or electric activities which cannot be charged directly and which apply to both Duke Energy Kentucky and Duke Energy Ohio.

Q. WHAT TYPES OF EXPENDITURES ARE CHARGED DIRECTLY VERSUS ALLOCATED TO DUKE ENERGY KENTUCKY?

A. The majority of common costs for Duke Energy Kentucky and Duke Energy Ohio are direct charged to the appropriate affiliate. Expenditures incurred directly for a specific project can be charged directly to Duke Energy Kentucky. A small portion of common costs may be allocated to Duke Energy Kentucky from Duke Energy Ohio. These costs include certain metering and customer related costs.

D. COST ALLOCATIONS FOR COMMON COSTS SHARED BY DUKE ENERGY KENTUCKY AND DUKE ENERGY'S CAROLINA UTILITIES.

Q. PLEASE EXPLAIN THE AFFILIATE CHARGES FROM DUKE ENERGY CAROLINAS AND DUKE ENERGY PROGRESS TO DUKE ENERGY KENTUCKY?

A. As part of the Duke Energy Progress Energy merger certain employees who were engaged in core utility functions that primarily supported the Carolina utilities were transferred in 2013 from DEBS into one of the Carolina utilities. While these employees primarily support the Carolinas, they also provide support to other jurisdictions including Duke Energy Kentucky. As a result of the transfer of employees there was an increase in charges from the Carolinas that was previously incurred from DEBS.

Q. WHAT TYPES OF CHARGES ARE ALLOCATED TO DUKE ENERGY KENTUCKY FROM DUKE ENERGY'S CAROLINA UTILITIES?

A. Charges allocated to Duke Energy Kentucky from Duke Energy's Carolina utilities represent a portion of costs originating on the Carolina Utilities books that apply to electric and/or gas activities which cannot be charged directly and apply to multiple Duke Energy jurisdictions including Duke Energy Kentucky.

Q. WHAT TYPES OF EXPENDITURES ARE CHARGED DIRECTLY VERSUS ALLOCATED TO DUKE ENERGY KENTUCKY?

A. The majority of common costs for Duke Energy Kentucky and Duke Energy's Carolina utilities are direct charged to the appropriate affiliate. Expenditures incurred directly for a specific project can be charged directly to Duke Energy

Kentucky. A small portion of common costs are allocated to Duke Energy's utilities from the Carolina's including Duke Energy Kentucky. These costs are primarily customer operations related, but also include smaller amounts for engineering, construction, operation, maintenance and fuel purchasing related costs.

E. <u>A&G COST ALLOCATIONS BETWEEN DUKE ENERGY KENTUCKY'S GAS AND ELECTRIC OPERATIONS</u>

Q. WHAT TYPES OF EXPENDITURES ARE CHARGED DIRECTLY VERSUS ALLOCATED TO DUKE ENERGY KENTUCKY GAS OR ELECTRIC OPERATIONS?

A. Most expenditures incurred directly for a specific project can be charged directly to a gas or an electric account. Certain administrative costs for general support functions, such as Accounts Payable and Accounting, are common to both gas and electric operations, and must be allocated. In addition, a portion of those costs is also capitalized.

Q. HOW HAVE THE ALLOCATION BASES FOR A&G EXPENDITURES BEEN DETERMINED?

A. To the extent that costs cannot be directly charged to gas and/or electric expense, they are allocated using a subset of the bases specified in the Operating Company Service Agreement. Annually, a cost study is conducted, applying the applicable data to this subset of allocation. From these cost studies, the allocation percentages of each allocable OU is updated to reflect the current underlying foundation of the allocation ratios. For example, annually, the OU based on the labor dollars ratio, which is primarily utilized for employee related costs, is updated to reflect the labor dollars in both the gas and electric functions of Duke Energy Kentucky.

Q. HOW IS THIS INFORMATION USED TO DETERMINE ASSIGNMENT OF COMMON A&G COSTS?

A. The cost allocation process for common A&G expenditures allocates costs based on statistical data that best relates to the specific activity to be allocated. For example employee related costs to be allocated are distributed based on the labor dollars ratio.

Q. WERE THE CURRENT ALLOCATION PROCESSES YOU DESCRIBED REFLECTED IN THE FORECASTED TEST PERIOD OF THIS CASE?

A. Yes.

Q. DO YOU ANTICIPATE THE COST ALLOCATION PROCESSES TO HAVE A MATERIAL IMPACT TO THE AMOUNT OF EXPENDITURES ALLOCATED TO DUKE ENERGY KENTUCKY'S ELECTRIC OPERATIONS ON AN ONGOING BASIS?

A. No. Many of the allocation factors are the same as the previous allocation factors. All of the allocation factors have been developed with the intent of assigning costs consistent with cost causation. Given that objective, I do not anticipate a material impact to the amount of expenditures allocated to Duke Energy Kentucky's electric operations. In fact, with the various consolidation efforts that Duke Energy has undertaken as a result of the various mergers since Duke Energy Kentucky's last base electric rate case, while the source of the allocation has changed due to office consolidation efforts and best practices, the overall amount of costs has not materially changed. As new cost centers were created, old cost centers were eliminated through consolidation efforts to gain efficiencies. In fact, as explained by Duke Energy Kentucky witness Mr. William Don Wathen Jr., the Company has diligently controlled its operation and maintenance (O&M) over that time and, except for an increase in expenses with the acquisition of Dayton Power & Light's share of East Bend in 2014, there has been very little change in non-production O&M since the time of the last rate case.

IV. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 16(7)(u).

A. FR 16(7)(u) contains the affiliate allocations during the base year, forecasted test year and previous three calendar years.

Q. PLEASE DESCRIBE FR 16(7)(u), PAGES 1 AND 2 OF 5.

A. FR 16(7)(u), pages 1 and 2 of 5, outline the service functions and methods used during the test year according to the Operating Company Service and Cost-based Non-Utility Service Agreements to allocate costs that could not be charged directly by DEBS to the regulated and non-regulated Duke Energy affiliates, including Duke Energy Kentucky. FR 16(7)(u), page 2(a) of 5, summarizes the total amount of expenditures charged from DEBS to Duke Energy Kentucky for the three years ended December 31, 2014, 2015, and 2016, and for the base period and the forecasted test period which include the twelve month periods ending November 30, 2017, and March 31, 2019, respectively.

Q. ARE THE ALLOCATION METHODS LISTED IN FR 16(7)(u), PAGE 2 OF 5 THE SAME COST ALLOCATION METHODS CONTAINED IN THE UTILITY SERVICE AGREEMENT APPROVED FOR USE IN 2010?

A. The allocation methods listed in FR 16(7)(u), page 2 of 5, are the 20 allocation methods contained in the current Utility Service Agreement.

Q. PLEASE BRIEFLY DESCRIBE FR 16(7)(u), PAGES 2(a) OF 5.

A. FR 16(7)(u), page 2(a) of 5, provides the bases used to allocate common charges between DEBS and Duke Energy Kentucky. FR 16(7)(u), page 2(a) identifies 16 allocation methods used during the test period to allocate to Duke Energy Kentucky which are either specifically identified or a combination of the allocation methods identified on FR 16(7)(u) 2 of 5. FR 16(7)(u), page 2(a) of 5, provides the amount of these costs allocated to Duke Energy Kentucky for the three years ended December 31, 2014, 2015 and 2016, for the base period, and for the forecasted test period ending November 30, 2017, and March 31, 2019, respectively.

Q. PLEASE BRIEFLY DESCRIBE FR 16(7)(u), PAGES 3 AND 3(a) OF 5

A. FR 16(7)(u), page 3 of 5, describes the process for assigning costs between Duke Energy Ohio and Duke Energy Kentucky which originate on Duke Energy Ohio's books and are directly assigned or allocated to Duke Energy Kentucky. FR 16(7)(u), page 3(a) of 5, provides the bases used to allocate charges and the amount of these costs allocated to Duke Energy Kentucky for the three years ended December 31, 2014, 2015 and 2016, for the base period, and for the forecasted test period ending November 30, 2017, and March 31, 2019, respectively.

Q. PLEASE BRIEFLY DESCRIBE FR 16(7)(u), PAGES 4 AND 4(a) OF 5

A. FR 16(7)(u), page 4 of 5, describes the purpose and process for assigning costs between Duke Energy Carolina, Duke Energy Progress and Duke Energy Kentucky, which originate on Duke Energy's Carolina utilities books and are directly assigned or allocated to Duke Energy Kentucky. FR 16(7)(u), page 4(a) of 5, provides the bases used to allocate charges and the amount of these costs allocated to Duke Energy Kentucky for the three years ended December 31, 2014, 2015 and 2016, for the base period, and for the forecasted test period ending November 30, 2017, and March 31, 2019, respectively.

Q. PLEASE BRIEFLY DESCRIBE FR 16(7)(u), PAGES 5 AND 5(a) OF 5.

A. FR 16(7)(u), page 5 of 5, provides the bases used to allocate A&G charges between gas and electric operations for those items that cannot be directly charged. FR 16(7)(u), page 5(a) of 5, summarizes the total amount of A&G expenditures allocated between gas and electric A&G expense accounts for the three years ended December 31, 2014, 2015 and 2016, for the base period, and the forecasted test period ending November 30, 2017, and March 31, 2019, respectively.

Q. ARE THE ALLOCATIONS INDICATED ON FR 16(7)(u), PAGE 5 OF 5 USED TO DETERMINE ALL CHARGES THAT SHOULD BE RECORDED TO GAS AND ELECTRIC OPERATIONS FOR BOTH CAPITAL AND EXPENSE ACCOUNTS?

A. No. Expenditures applicable to gas or electric operations are charged directly whenever possible. For example, employees performing work on a specific project will charge direct to the appropriate gas and/or electric expense or capital account.

Q. IN YOUR OPINION, ARE THE ALLOCATION FACTORS AND COSTS ASSIGNED TO DUKE ENERGY KENTUCKY REASONABLE?

A. Yes. These costs are reasonable. All costs are assigned and allocated in compliance with these agreements. The Duke Energy and the Company's accounting processes are audited and verified to ensure that costs are properly assigned and allocated. The amount of costs that are being allocated to Duke Energy Kentucky are consistent with what the Company would otherwise experience if it did not have the benefit of being a part of a larger family of utilities. In fact, based upon the Duke Energy market research for determining salaries for shared and utility employees, the costs of common business functions that are allocated to Duke Energy Kentucky and shared between among all affiliated companies result in a lower overall cost to the individual companies than if they had to maintain separate and duplicative individual functions.

Q. DID YOU PROVIDE ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. Yes, I supplied Mr. Pratt with the allocation factors in effect for his use in developing the forecasted financial data.

V. CONCLUSION

Q. WERE ATTACHMENTS JRS-1, JRS-2, JRS-3, JRS-4, JRS-5, THE INFORMATION YOU PREPARED FOR MR. PRATT AND FR 16(7)(u) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Jeffrey R. Setser, Director of Allocations and Reporting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Jeffrey R. Setser

Jeffrey R. Setser Affiant

Subscribed and sworn to before me by Jeffrey R. Setser on this 16 day of August, 2017.

Patricia C Ross

NOTARY PUBLIC

My Commission Expires: 10-17-2019

PATRICIA C. ROSS
NOTARY PUBLIC
Mecklenburg County
North Carolina

SERVICE COMPANY
UTILITY SERVICE AGREEMENT

This Service Company Utility Service Agreement (this "Agreement") is by and among Duke Energy Carolinas, LLC ("DEC"), a North Carolina limited liability company, Duke Energy Ohio, Inc., an Ohio corporation ("DEO"), Duke Energy Indiana, LLC an Indiana limited liability company ("DEI"), Duke Energy Kentucky, Inc., a Kentucky corporation ("DEK"), Duke Energy Progress, LLC, a North Carolina limited liability company ("DEP"), Piedmont Natural Gas Company, Inc., a North Carolina corporation ("Piedmont"), Duke Energy Florida, LLC ("DEF"), a Florida limited liability company, and Duke Energy Business Services LLC ("DEBS"), a Delaware limited liability company. DEBS is sometimes hereinafter referred to as a "Service Company." DEC, DEO, DEI, DEK, DEP, DEF, and Piedmont are sometimes hereinafter referred to individually as a "Client Company" and collectively as the "Client Companies". The Effective Date as stated herein is the date on which this Agreement is executed or, as may be required, submitted to the appropriate regulatory body for approval, whichever occurs last. This Agreement supersedes and replaces in its entirety all previous Service Company Utility Service Agreements dated before the Effective Date of this Agreement.

WITNESSETH

WHEREAS, each of the Client Companies and the Service Company are direct or indirect subsidiaries of Duke Energy Corporation;

WHEREAS, the Service Company and the Client Companies have entered into this Agreement whereby the Service Company agrees to provide and the Client Companies agree to accept and pay for various services as provided herein at cost, except to the extent otherwise required by Section 482 of the Internal Revenue Code; and

WHEREAS, economies and efficiencies benefiting the Client Companies will result from the performance by the Service Company of services as herein provided;

NOW, THEREFORE, in consideration of the premises and the mutual agreements herein contained, the parties to this Agreement covenant and agree as follows:

ARTICLE I – SERVICES

Section 1.1 The Service Company shall furnish to the Client Companies, upon the terms and conditions hereinafter set forth, such of the services described in Appendix A hereto, at such times, for such periods and in such manner as the Client Companies may from time to time request and which the Service Company concludes it is equipped to perform. The Service Company shall also provide Client Companies with such special services, including without limitation cost management services, in addition to those services described in Appendix A hereto, as may be requested by a Client Company and which the Service Company concludes it is equipped to perform. In supplying such services, the Service Company may (i) arrange, where it deems appropriate, for the services of such experts, consultants, advisers and other persons with necessary qualifications as are required for or pertinent to the rendition of such services, and (ii) tender payments to third parties as agent for and on behalf of Client Companies, with such charges being passed through to the appropriate Client Companies.

Section 1.2 Each of the Client Companies shall take from the Service Company such of the services described in Section 1.1 and such additional general or special services, whether or not now contemplated, as are requested from time to time by the Client Companies and which the Service Company concludes it is equipped to perform.

Section 1.3 The services described herein shall be directly assigned, distributed or allocated by activity, process, project, responsibility center, work order or other appropriate basis. A Client Company shall have the right from time to time to amend, alter or rescind any activity, process, project, responsibility center or work order, provided that (i) any such amendment or alteration which results in a material change in the scope of the services to be performed or equipment to be provided is agreed to by the Service Company, (ii) the cost for the services covered by the activity, process, project, responsibility center or work order shall include any expense incurred by the Service Company as a direct result of such amendment, alteration or rescission of the activity, process, project, responsibility center or work order, and (iii) no amendment, alteration or rescission of an activity, process, project, responsibility center or work order shall release a Client Company from liability for all costs already incurred by or contracted for by the Service Company pursuant to the activity, process, project, responsibility center or work order, regardless of whether the services associated with such costs have been completed.

Section 1.4 The Service Company shall maintain a staff trained and experienced in the design, construction, operation, maintenance and management of public utility properties.

ARTICLE II - COMPENSATION

Section 2.1 Except to the extent otherwise required by Section 482 of the Internal Revenue Code, as compensation for the services to be rendered hereunder, each of the Client Companies shall pay to the Service Company all costs which reasonably can be identified and related to particular services performed by the Service Company for or on its behalf. Where more than one Client Company is involved in or has received benefits from a service performed, costs will be directly assigned, distributed or allocated, as set forth in Appendix A hereto, between or among such companies on a basis reasonably related to the service performed to the extent reasonably practicable.

Section 2.2 The method of assignment, distribution or allocation of costs described in Appendix A shall be subject to review annually, or more frequently if appropriate. Such method of assignment, distribution or allocation of costs may be modified or changed by the Service Company without the necessity of an amendment to this Agreement, provided that in each instance, all services rendered hereunder shall be at actual cost thereof, fairly and equitably assigned, distributed or allocated, except to the extent otherwise required by Section 482 of the Internal Revenue Code. The Service Company shall promptly advise the Client Companies of any material changes in such method of assignment, distribution or allocation. As appropriate, the Client Companies shall advise the North Carolina Utilities Commission ("NCUC"), the Public Service Commission of South Carolina, the Florida Public Service Commission; the Indiana Utility Regulatory Commission, the Public Utilities Commission of Ohio, the Kentucky Public Service Commission, and the Tennessee Regulatory Authority ("the "Affected State Commissions") of any such changes. Such notice shall be in compliance with the requirements of applicable state law, regulations and regulatory conditions.

Section 2.3 The Service Company shall render a monthly statement to each Client Company which shall reflect the billing information necessary to identify the costs charged for that month. By the last day of each month, each Client Company shall remit to the Service Company all charges billed to it. For avoidance of doubt, the Service Company and each Client Company may satisfy the foregoing requirement by recording billings and payments required hereunder in their common accounting systems without rendering paper or electronic monthly statements or remitting cash payments.

Section 2.4 Subject to Section 482 of the Internal Revenue Code, it is the intent of this Agreement that the payment for services rendered by the Service Company to the Client Companies shall cover all the costs of its doing business (less the cost of services provided to affiliated companies not a party to this Agreement and to other non-affiliated companies, and credits for any miscellaneous income items), including, but not limited to, salaries and wages, office supplies and expenses, outside services employed, property insurance, injuries and damages, employee pensions and benefits, miscellaneous general expenses, rents, maintenance of structures and equipment, depreciation and amortization and compensation for use of capital. Without limitation of the foregoing, "cost," as used in this Agreement, means fully embedded cost, namely, the sum of (1) direct costs, (2) indirect costs and (3) costs of capital.

ARTICLE III - TERM

Section 3.1 This Agreement is entered into as of the Effective Date and shall continue in force with respect to a Client Company until terminated by the Service Company and Client Company with respect to such Client Company (provided that no such termination with respect to less than all of the Client Companies shall thereby affect the term of this Agreement or any of the provisions hereof) or until terminated by unanimous agreement of all the parties then signatory to this Agreement.

ARTICLE IV – ACCOUNTS AND RECORDS

Section 4.1 The Service Company shall utilize the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission.

Section 4.2 The Service Company shall permit each Affected State Commission and applicable statutory utility consumer representative(s), together with other interested parties as required under applicable law, access to its accounts and records, including the basis and computation of allocations, necessary for each Affected State Commission to review a Client Company's operating results.

ARTICLE V – MISCELLANEOUS

Section 5.1 Counterparts. This Agreement may be executed in one or more counterparts, all of which shall be considered one and the same agreement and shall become effective when one or more counterparts have been signed by each party and delivered to the other parties.

Section 5.2 Entire Agreement; No Third Party Beneficiaries. This Agreement (including Appendix A and any other appendices or other exhibits or schedules hereto) (i) constitutes the entire agreement, and supersedes any prior agreements and understandings, both written and oral, among the parties with respect to the subject matter of this Agreement; and (ii) is not intended to confer upon any person other than the parties hereto any rights or remedies.

Section 5.3 Governing Law. This Agreement shall be governed by, and construed in accordance with, the laws of the State of New York, regardless of the laws that might otherwise govern under applicable principles of conflict of laws.

Section 5.4 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of each of the other parties. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 5.5 Amendments. This Agreement may not be amended except by an instrument in writing signed on behalf of each of the parties. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any Affected State Commission for its review or otherwise, each Client Company shall comply in all respects with any such requirements.

Section 5.6 Interpretation. When a reference is made in this Agreement to an Article, Section or Appendix or other Exhibit, such reference shall be to an Article or Section of, or an Appendix or other Exhibit to, this Agreement unless otherwise indicated. The headings contained in this Agreement are for convenience of reference only and shall not affect in any way the meaning or interpretation of this Agreement. Whenever the words "include", "includes" or "including" are used in this Agreement, they shall be deemed to be followed by the words "without limitation". The words "hereof", "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement. The definitions contained in this Agreement are applicable to the singular as well as the plural forms of such terms and to the masculine as well as to the feminine and neuter genders of such term. References to a person are also to its permitted successors and assigns.

Section 5.7 DEC, DEP, and Piedmont Conditions. In addition to the terms and conditions set forth herein, with respect to DEC and DEP, the provisions set out in Appendix B are hereby incorporated herein by reference. In addition, DEC's, DEP's, and Piedmont's participation in this Agreement is explicitly subject to the Regulatory Conditions and Code of Conduct approved by the NCUC in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued, in NCUC Docket Nos. E-2, Sub 1095, E-7, Sub 1100, and G-9, Sub 682. In the event of any conflict between the provisions of this Agreement and the approved Regulatory Conditions and Code of Conduct provisions, the Regulatory Conditions and Code of Conduct shall govern.

IN WITNESS WHEREOF, the parties hereto have caused this Service Agreement to be executed as of ________, 201_.

DUKE ENERGY BUSINESS SERVICES LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY CAROLINAS, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY OHIO, INC.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY INDIANA, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY KENTUCKY, INC.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY PROGRESS, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY FLORIDA, LLC

By: ____________________________
Nancy M. Wright
Assistant Corporate Secretary

PIEDMONT NATURAL GAS COMPANY, INC.

By: ____________________________
Nancy M. Wright
Assistant Corporate Secretary

APPENDIX A

Description of Services and Determination
of Charges for Services

I. The Service Company will maintain an accounting system for accumulating all costs on an activity, process, project, responsibility center, work order, or other appropriate basis. To the extent practicable, time records of hours worked by Service Company employees will be kept by activity, process, project, responsibility center or work order. Charges for salaries will be determined from such time records and will be computed on the basis of employees' labor costs, including the cost of fringe benefits, indirect labor costs and payroll taxes. Records of employee-related expenses and other indirect costs will be maintained for each functional group within the Service Company (hereinafter referred to as "Function"). Where identifiable to a particular activity, process, project, responsibility center or work order, such indirect costs will be directly assigned to such activity, process, project, responsibility center or work order. Where not identifiable to a particular activity, process, project, responsibility center or work order, such indirect costs within a Function will be distributed in relationship to the directly assigned costs of the Function. For purposes of this Appendix A, any costs not directly assigned or distributed by the Service Company will be allocated monthly.

II. Service Company costs accumulated for each activity, process, project, responsibility center or work order will be directly assigned, distributed, or allocated to the Client Companies or other Functions within the Service Company as follows:

1. Costs accumulated in an activity, process, project, responsibility center or work order for services specifically performed for a single Client Company or Function will be directly assigned and charged to such Client Company or Function.

2. Costs accumulated in an activity, process, project, responsibility center or work order for services specifically performed for two or more Client Companies or Functions will be distributed among and charged to such Client Companies or Functions. The appropriate method of distribution will be determined by the Service Company on a case-by-case basis consistent with the nature of the work performed and will be based on the application of one or more of the methods described in paragraphs IV and V of this

Appendix A. The distribution method will be provided to each such affected Client Company or Function.

3. Costs accumulated in an activity, process, project, responsibility center or work order for services of a general nature which are applicable to all Client Companies or Functions or to a class or classes of Client Companies or Functions will be allocated among and charged to such Client Companies or Functions by application of one or more of the methods described in paragraphs IV and V of this Appendix A.

III. For purposes of this Appendix A, the following definitions or methodologies shall be utilized:

1. Where applicable, the following will be utilized to convert gas sales to equivalent electric sales: 1 cubic foot of gas sales equals 0.303048 kilowatt-hour of electric sales (based on electricity at 3412 Btu/kWh and natural gas at 1034 Btu/cubic foot).

2. "Domestic utility" refers to a utility which operates in the contiguous United States of America.

3. “Gross margin” refers to revenues as defined by Generally Accepted Accounting Principles, less cost of sales, including but not limited to fuel, purchased power, emission allowances and other cost of sales.

4. “Distribution” means electric distribution and local gas distribution as applicable.

5. “Distribution Lines” mean electric power lines at distribution voltages measured in circuit miles, and gas mains and lines, as applicable.

The weights utilized in the weighted average ratios in paragraph V of this Appendix A shall represent the percentage relationship of the activities associated with the function for which costs are to be allocated. For example, if an expense item is to be allocated on the weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the Total Property, Plant and Equipment (“PP&E”) Ratio, and the activity to be allocated is one-third gross margin related, one-third labor related and one-third PP&E related, 33 percent of the Gross Margin Ratio would be utilized, 33 percent of the Labor Dollars Ratio and 34 percent of the PP&E Ratio would be utilized. To illustrate this application, assuming that the Gross Margin Ratio were 53.75 percent for Company A and 46.25 percent for Company B, the Labor Dollars Ratio were 25 percent for Company A and 75 percent for Company B, and the Total PP&E Ratio were 60 percent for Company A and 40 percent for Company B, the following weighted average ratio would be computed:

		Company A		Company B	
Activity	Weight	Ratio	Weighted	Ratio	Weighted
Gross Margin Ratio	33%	53.75%	17.74%	46.25%	15.26%
Labor Dollars Ratio	33%	25.00%	8.25%	75.00%	24.75%
Total Property, Plant and Equipment Ratio	34%	60.00%	20.40%	40.00%	13.60%
	100%		46.39%		53.61%

IV. The following allocation methods will be applied, as specified in paragraph V of this Appendix A, to assign costs for services applicable to two or more clients and/or to allocate costs for services of a general nature.

1. Sales Ratio

A ratio, based on the applicable domestic firm kilowatt-hour electric sales (and/or the equivalent cubic feet of gas sales, where applicable), excluding intra-system sales, for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable), This ratio will be determined annually, or at such time as may be required due to a significant change.

2. Electric Peak Load Ratio

A ratio, based on the sum of the applicable monthly domestic firm electric maximum system demands for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually, or at such time as may be required due to a significant change.

3. <u>Number of Customers Ratio</u>

   A ratio, based on the sum of the applicable domestic firm electric customers (and/or gas customers, where applicable) at the end of a recent month in the preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually, or at such time as may be required due to a significant change.

4. <u>Number of Employees Ratio</u>

   A ratio, based on the applicable number of employees at the end of a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually, or at such time as may be required due to a significant change.

5. <u>Construction-Expenditures Ratio</u>

   A ratio, based on the applicable projected construction expenditures for the following twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). Separate ratios will be computed for total construction expenditures and appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually, or at such time as may be required due to a significant change.

6. Miles of Distribution Lines Ratio

In the case of electric Distribution, a ratio, based on the applicable installed circuit miles of domestic electric Distribution Lines, and in the case of gas Distribution, a ratio, based on the applicable installed miles of domestic gas Distribution Lines, in either case at the end of the preceding calendar year, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies. This ratio will be determined annually, or at such time as may be required due to a significant change.

7. Circuit Miles of Electric Transmission Lines Ratio

A ratio, based on the applicable installed circuit miles of domestic electric transmission lines at the end of the preceding calendar year, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies. This ratio will be determined annually, or at such time as may be required due to a significant change.

8. Millions of Instructions Per Second Ratio

A ratio, based on the sum of the applicable number of millions of instructions per second (MIPS) used to execute mainframe computer software applications for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company or Service Company Function, and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually, or at such time as may be required due to a significant change.

9. Revenues Ratio

A ratio, based on the total applicable revenues for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

10. Inventory Ratio

A ratio, based on the total applicable inventory balance for the preceding year, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). Separate ratios will be computed for total inventory and the appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually or at such time as may be required due to a significant change.

11. Procurement Spending Ratio

A ratio, based on the total amount of applicable procurement spending for the preceding year, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. Separate ratios will be computed for total procurement spending and appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually or at such time as may be required due to a significant change.

12. Square Footage Ratio

A ratio, based on the total amount of applicable square footage occupied in a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

13. Gross Margin Ratio

A ratio, based on the total applicable gross margin for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

14. Labor Dollars Ratio

A ratio, based on the total applicable labor dollars for a preceding twelve consecutive calendar month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

15. Number of Personal Computer Work Stations Ratio

A ratio, based on the total number of applicable personal computer work stations at the end of a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

16. Number of Information Systems Servers Ratio

A ratio, based on the total number of applicable servers at the end of a recent month in the preceding twelve consecutive month period, the numerator of which is for a Client Company or Service Company Function and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable) and/or the Service Company. This ratio will be determined annually or at such time as may be required due to a significant change.

17. Total Property, Plant and Equipment Ratio

A ratio, based on the total applicable Property, Plant and Equipment balance (net of accumulated depreciation and amortization) for the preceding year, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

18. Generating Unit MW Capability / Maximum Dependable Capacity (MDC) Ratio A ratio, based on the total applicable installed megawatt capability for the preceding year, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). This ratio will be determined annually or at such time as may be required due to a significant change.

19. Number of Meters Ratio

A ratio, based on the number of electric and/or gas meters, as applicable, the numerator of which is for a Client Company and the denominator of which is for all domestic utility Client Companies. Separate ratios will be computed for appropriate meter classifications (e.g., type of metering technology). This ratio will be determined annually, or at such time as may be required due to a significant change.

20. <u>O&M Expenditures Ratio</u>

A ratio, based on the operation and maintenance (O&M) expenditures for a prior twelve month period, the numerator of which is for a Client Company and the denominator of which is for all Client Companies (and Duke Energy Corporation's non-utility and non-domestic utility affiliates, where applicable). Separate ratios will be computed for total O&M expenditures and appropriate functional plant (i.e., production, transmission, Distribution, and general) classifications. This ratio will be determined annually.

V. A description of each Function's activities, which may be modified from time to time by the Service Company, is set forth below in paragraph "a" under each Function. As described in paragraph II, "1" and "2" of this Appendix A, where identifiable, costs will be directly assigned or distributed to Client Companies or to other Functions of the Service Company. For costs accumulated in activities, processes, projects, responsibility centers, or work orders which are for services of a general nature that cannot be directly assigned or distributed, as described in paragraph II, "3" of this Appendix A, the method or methods of allocation are set forth below in paragraph "b" under each Function. For any of the functions set forth below other than Information Systems, Transportation, Human Resources or Facilities, costs of a general nature to be allocated pursuant to this Agreement shall exclude costs of a general nature which have been allocated to affiliated companies not a party to this Agreement. Substitution or changes may be made in the methods of allocation hereinafter specified, as may be appropriate, and will be provided to state regulatory agencies and to each Client Company. Any such substitution or changes shall be in compliance with the requirements of applicable state law, regulations and regulatory conditions.

1. <u>Information Systems</u>

   a. Description of Function

   Provides communications and electronic data processing services. The activities of the Function include:

   (1) Development and support of mainframe computer software applications.

   (2) Procurement and support of personal computers and related network and software applications.

   (3) Development and support of distributed computer software applications (e.g., servers).

   (4) Installation and operation of communications systems.

   (5) Information systems management and support services.

   b. Method of Allocation

   (1) Development and support of mainframe computer software applications - allocated between the Client Companies and other Functions of the Service Company based on the number of Millions of Instructions per Second Ratio (MIPS).

   (2) Procurement and support of personal computers and related network and software applications - allocated to the Client Companies and to other Functions of the Service Company based on the Number of Personal Computer Work Stations Ratio.

   (3) Development and support of distributed computer software applications - allocated to the Client Companies and to other Functions of the Service Company based on the Number of Information Systems Servers Ratio.

   (4) Installation and operation of communications systems - allocated to the Client Companies and to other Functions of the Service Company based on the Number of Employees Ratio.

   (5) Information systems management and support services – allocated to the Client Companies and to other Functions of the Service Company based on the Number of Personal Computer Work Stations Ratio.

2. Meters
   a. Description of Function

      Procures, tests and maintains meters.
   b. Method of Allocation

      Allocated to the Client Companies based on the Number of Customers Ratio.

3. Transportation
   a. Description of Function
      (1) Procures and maintains vehicles and equipment.
      (2) Procures and maintains aircraft and equipment.
   b. Method of Allocation
      (1) The costs of maintaining vehicles and equipment are allocated to the Client Companies and to other Functions of the Service Company based on the Number of Employees Ratio.
      (2) The costs of maintaining aircraft and equipment are allocated to the Client Companies and to other Functions of the Service Company based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

4. System Maintenance
   a. Description of Function

      Coordinates maintenance and support of electric transmission systems and Distribution systems.
   b. Method of Allocation
      (1) Services related to electric transmission systems - allocated to the Client Companies based on the Circuit Miles of Electric Transmission Lines Ratio.
      (2) Services related to electric Distribution systems - allocated to the Client Companies based on the Miles of Distribution Lines Ratio.
      (3) Services related to gas Distribution systems – allocated to the Client Companies based on the Labor Dollars Ratio.

5. <u>Marketing and Customer Relations</u>

a. Description of Function

Advises the Client Companies in relations with domestic utility customers.

The activities of the Function include:

(1) Design and administration of sales and demand-side management programs.

(2) Customer meter reading, billing and payment processing.

(3) Customer services including the operation of call center.

b. Method of Allocation

(1) Design and administration of sales and demand-side management programs - allocated to the Client Companies based on the Number of Customers Ratio.

(2) Customer billing and payment processing - allocated to the Client Companies based on the Number of Customers Ratio.

(3) Customer Services - allocated to the Client Companies based on the Number of Customers Ratio.

6. <u>Transmission and Distribution Engineering and Construction</u>

a. Description of Function

Designs and monitors construction of electric transmission and Distribution Lines and associated facilities. Prepares cost and schedule estimates, visits construction sites to ensure that construction activities coincide with plans, and administers construction contracts.

b. Method of Allocation

(1) Transmission engineering and construction allocated to the Client Companies based on the Electric Transmission Plant's Construction-Expenditures Ratio.

(2) Distribution engineering and construction allocated to the Client Companies based on the Distribution plant's Construction-Expenditures Ratio.

7. Power Engineering and Construction

   a. Description of Function

   Designs, monitors and supports the construction and retirement of electric generation facilities. Prepares specifications and administers contracts for construction of new electric generating units, improvements to existing electric generating units, and the retirement of existing electric generating equipment, including developing associated operating processes with operations personnel. Prepares cost and schedule estimates and visits construction sites to ensure that construction and retirement activities meet schedules and plans.

   b. Method of Allocation

   Allocated to the Client Companies based on the Electric Production Plant's Construction-Expenditures Ratio.

8. Human Resources

   a. Description of Function

   Establishes and administers policies and supervises compliance with legal requirements in the areas of employment, compensation, benefits and employee health and safety. Processes payroll and employee benefit payments. Supervises contract negotiations and relations with labor unions.

   b. Method of Allocation

   Allocated to the Client Companies and to other Functions of the Service Company based on the Number of Employees Ratio.

9. Supply Chain

   a. Description of Function

   Provides services in connection with the procurement of materials and contract services, processes payments to vendors, and provides management of material and supplies inventories.

   b. Method of Allocation

   (1) Procurement of materials and contract services and vendor payment processing - allocated to the Client Companies and to other Functions of the Service Company based on the Procurement Spending Ratio.

(2) Management of materials and supplies inventory – allocated to the Client Companies on the Inventory Ratio.

10. Facilities
    a. Description of Function
    Operates and maintains office and service buildings. Provides security and housekeeping services for such buildings and procures office furniture and equipment.
    b. Method of Allocation
    Allocated to the Client Companies and to other Functions of the Service Company based on the Square Footage Ratio.

11. Accounting
    a. Description of Function
    Maintains the books and records of Duke Energy Corporation and its affiliates, prepares financial and statistical reports, prepares tax filings and supervises compliance with the laws and regulations.
    b. Method of Allocation
    (1) Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.
    (2) Certain merger related costs are allocated based on Generating Unit MW Capability/ MDC Ratio.

12. Power and Gas Planning and Operations
    a. Description of Function
    Coordinate the planning, management and operation of Duke Energy Corporation's power generation, transmission and Distribution systems. The activities of the Function include:
    (1) System Planning - planning of additions and retirements to the electric generation units and transmission and Distribution systems belonging to the regulated utilities owned by Duke Energy Corporation.

(2) System Operations - coordination of the dispatch and operation of the electric generating units and transmission and Distribution systems belonging to the regulated utilities owned by Duke Energy Corporation.

(3) Power Operations – provides management and support services for the electric generation units owned or operated by subsidiaries of Duke Energy Corporation.

(4) Wholesale Power Operations – coordination of Duke Energy Corporation's wholesale power operations.

b. Method of Allocation

(1) System Planning

(a) Generation planning - allocated to the Client Companies based on the Electric Peak Load Ratio.

(b) Transmission planning – allocated to the Client Companies based on the Electric Peak Load Ratio.

(c) Electric Distribution planning - allocated to the Client Companies based on a weighted average of the Miles of Distribution Lines Ratio and the Electric Peak Load Ratio.

(d) Gas Distribution planning – allocated to the Client Companies based on the Construction-Expenditures Ratio.

(2) System Operations –

(a) Generation Dispatch - allocated to the Client Companies based on the Sales Ratio.

(b) Transmission Operations - allocated to the Client Companies based on a weighted average of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio.

(c) Electric Distribution Operations - allocated to the Client Companies based on a weighted average of the Miles of Distribution Lines Ratio and the Electric Peak Load Ratio.

(d) Gas Distribution Operations – allocated to the Client Companies based on the Construction-Expenditures Ratio.

(3) Power Operations – allocated to the Client Companies based on the Generating Unit MW Capability / Maximum Dependable Capacity (MDC) Ratio.

(4) Wholesale Power Operations – allocated to the Client Companies based on the Sales Ratio.

13. <u>Public Affairs</u>

a. Description of Function

Prepares and disseminates information to employees, customers, government officials, communities and the media. Provides graphics, reproduction lithography, photography and video services.

b. Method of Allocation

(1) Services related to corporate governance, public policy, management and support services - allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

(2) Services related to utility specific activities - allocated to the Client Companies based on a weighted average of the Number of Customers Ratio and the Number of Employees Ratio.

14. <u>Legal</u>

a. Description of Function

Renders services relating to labor and employment law, litigation, contracts, rates and regulatory affairs, environmental matters, financing, financial reporting, real estate and other legal matters.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

15. <u>Rates</u>

a. Description of Function

Determines the Client Companies' revenue requirements and rates to electric and gas requirements customers. Administers interconnection and joint ownership agreements. Researches and forecasts customers' usage.

b. Method of Allocation

Allocated to the Client Companies based on the Sales Ratio.

16. <u>Finance</u>

a. Description of Function

Renders services to Client Companies with respect to investments, financing, cash management, risk management, claims and fire prevention. Prepares budgets, financial forecasts and economic analyses.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

17. <u>Rights of Way</u>

a. Description of Function

Purchases, surveys, records, and sells real estate interests for Client Companies.

b. Method of Allocation

(1) Services related to Distribution system - allocated to the Client Companies based on the Miles of Distribution Lines Ratio.

(2) Services related to electric generation system- allocated to the Client Companies based on the Electric Peak Load Ratio.

(3) Services related to electric transmission system – allocated to the Client Companies based on the Circuit Miles of Electric Transmission Lines Ratio.

18. <u>Internal Auditing</u>

a. Description of Function

Reviews internal controls and procedures to ensure that assets are safeguarded and that transactions are properly authorized and recorded.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

19. Environmental, Health and Safety

a. Description of Function

Establishes policies and procedures and governance framework for compliance with environmental, health and safety ("EHS") issues, monitors compliance with EHS requirements and provides EHS compliance support to the Client Companies' personnel.

b. Method of Allocation

(1) Services related to corporate governance, environmental policy, management and support services - allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollar Ratio and the PP&E Ratio.

(2) Services related to utility specific activities – allocated to the Client Companies based on the Sales Ratio.

20. Fuels

a. Description of Function

Procures coal, gas and oil for the Client Companies. Ensures compliance with price and quality provisions of fuel contracts and arranges for transportation of the fuel to the generating stations.

b. Method of Allocation

Allocated to the Client Companies based on the Sales Ratio.

21. Investor Relations

a. Description of Function

Provides communications to investors and the financial community, performs transfer agent and shareholder record keeping functions, administers stock plans and performs stock-related regulatory reporting.

b. Method of Allocation

Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

22. Planning
    a. Description of Function
       Facilitates preparation of strategic and operating plans, monitors trends and evaluates business opportunities.
    b. Method of Allocation
       Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

23. Executive
    a. Description of Function
       Provides general administrative and executive management services.
    b. Method of Allocation
       Allocated to the Client Companies based on a weighted average of the Gross Margin Ratio, the Labor Dollars Ratio and the PP&E Ratio.

24. Nuclear Development
    a. Description of Function
       Provides design, engineering, project management and licensing for potentially proposed new operating units.
    b. Method of Allocation
       Directly assigned/charged to participating jurisdictions.

APPENDIX B

Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Piedmont Natural Gas Company, Inc. Conditions

In connection with the NCUC approval of the Merger in NCUC Docket No. E-2, Sub 1095, Docket No. E-7, Sub 1100, and Docket No. G-5, Sub 682, the NCUC adopted certain Regulatory Conditions and a revised Code of Conduct governing transactions between DEC, DEP, Piedmont, and their affiliates. Pursuant to the Regulatory Conditions, the following provisions are applicable to DEC, DEP, and Piedmont:

(a) DEC's, DEP's and Piedmont's participation in this Agreement is voluntary. DEC, DEP, or Piedmont is not obligated to take or provide services or make any purchases or sales pursuant to this Agreement, and DEC, DEP, or Piedmont may elect to discontinue its participation in this Agreement at its election after giving any required notice;

(b) DEC, DEP or Piedmont may not make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder.

(c) DEC, DEP or Piedmont may not seek to reflect in rates any (A) costs incurred under this Agreement exceeding the amount allowed by the NCUC or (B) revenue level earned under this Agreement less than the amount imputed by the NCUC; and

(d) DEC, DEP or Piedmont shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of other entity's assertions, that the NCUC's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is, in whole or in part, (A) preempted by Federal Law or (B) not within the Commission's power, authority, or jurisdiction; DEC, DEP, and Piedmont will bear the full risk of any preemptive effects of Federal Law with respect to this Agreement.

OPERATING COMPANIES SERVICE AGREEMENT

This Operating Companies Service Agreement (this "Agreement") by and among Duke Energy Carolinas, LLC ("DEC"), a North Carolina limited liability company, Duke Energy Ohio, Inc. ("DEO"), an Ohio corporation, Duke Energy Indiana, LLC ("DEI"), an Indiana limited liability company, Duke Energy Kentucky, Inc. ("DEK"), a Kentucky corporation, Duke Energy Progress, LLC ("DEP"), a North Carolina limited liability company, and Duke Energy Florida, LLC ("DEF"), a Florida limited liability company and Piedmont Natural Gas Company, Inc., a North Carolina corporation ("Piedmont"),, supersedes and replaces in its entirety all previous Operating Company Service Agreements dated before the Effective Date of this Agreement. The Effective date as stated herein is the date on which this agreement is signed or, as may be required, submitted to the appropriate regulatory body for approval, whichever occurs last. DEC, DEO, DEI, DEK, DEP DEF and Piedmont are referred to collectively as the "Operating Companies" and, individually, an "Operating Company."

WITNESSETH:

WHEREAS, Duke Energy Corporation ("Duke Energy") is a Delaware corporation;

WHEREAS, each Operating Company is a subsidiary of Duke Energy and a public utility company;

WHEREAS, in the ordinary course of their businesses, Operating Companies maintain organizations of employees with technical expertise in matters affecting public utility companies and related businesses and own or acquire related equipment, facilities, properties and other resources; and

WHEREAS, subject to the terms and conditions herein set forth, and taking into consideration the parties' utility responsibilities or primary business operations, as the case may be, the parties hereto are willing, upon request from time to time, to perform such services, and in connection therewith to make available such equipment, facilities, properties and other resources, as they shall request from each other;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1. PROVISION OF SERVICES; LOANED EMPLOYEES

Section 1.1 Provision of Services.

(a) Except as hereinafter provided with respect to DEC, DEP, and Piedmont providing services for each other, upon receipt by a party hereto (in such capacity, a "Service Provider") of a written request in substantially the same form attached hereto as Exhibit A (a "Service Request") from another party hereto (in such capacity, a "Client Company") for the provision to such Client

Company of such services as are specified therein, including if applicable use of any related equipment, facilities, properties or other resources (collectively, "Services"), the Service Provider, if in its sole discretion it has available the personnel or other resources needed to perform the Service Request without impairment of its utility responsibilities or business operations, as the case may be, shall furnish such Services to the Client Company at such times, for such periods and in such manner as the Client Company shall have so requested and otherwise in accordance with the provisions hereof.

(b) For purposes of this Agreement, "Services" may include, but shall not be limited to, services in such areas as engineering and construction; operations and maintenance; installation services; equipment testing; generation technical support; environmental, health and safety; and procurement services (including, but not limited to, fuel procurement).

(c) "Services" may also include the use of assets, equipment and facilities, provided the Client Company compensates the Service Provider for such use in accordance with Article 3.

(d) For the avoidance of doubt, affiliate transactions involving sales or other transfers of assets, goods, energy commodities (including electricity, natural gas, coal and other combustible fuels) or thermal energy products are outside the scope of this Agreement.

Section 1.2 Loaned Employees.

(a) If specifically requested in connection with the provision of Services, Service Provider shall loan one or more of its employees to such Client Company, provided that such loan shall not, in the sole discretion of Service Provider, interfere with or impair Service Provider's utility responsibilities or business operations, as the case may be. After the commencement thereof, any such loaned employees may be withdrawn by Service Provider from tasks duly assigned by Client Company, prior to completion thereof as contemplated in the associated Service Request, only with the consent of Client Company (which shall not be unreasonably withheld or delayed), except in the event of a demonstrable emergency requiring the use of any such employees in another capacity for Service Provider.

(b) While performing work on behalf of Client Company, any such loaned employees shall be under its supervision and control, and Client Company shall be responsible for their actions to the same extent as though such persons were its employees (it being understood that such persons shall nevertheless remain employees of Service Provider and nothing herein shall be construed as creating an employer-employee relationship between any Client Company and any loaned employees). Accordingly, for the duration of any such loan, Service Provider shall continue to provide its loaned employees with the same payroll, pension, savings, tax withholding, unemployment, bookkeeping and other personnel support services then being provided by Service Provider to its other employees.

ARTICLE 2. SERVICE REQUESTS

Section 2.1 Procedure. All Services (including any loans of employees) (i) shall be performed in accordance with Service Requests issued by or on behalf of Client Company and accepted by Service Provider and (ii) shall be assigned to applicable activities, processes, projects, responsibility centers or on other appropriate bases to enable specific work to be properly assigned. Service Requests shall be as specific as practicable in defining the Services requested. Client Company shall have the right from time to time to amend or rescind any Service Request, *provided* that (a) Service Provider consents to any amendment that results in a material change in the scope of Services to be provided, (b) the costs associated with an amended or rescinded Service Request shall include the costs incurred by Service Provider as a result of such amendment or rescission, and (c) no amendment or rescission of a Service Request shall release Client Company from any liability for costs already incurred or contracted for by Service Provider pursuant to the original Service Request, regardless of whether any labor or the furnishing of any property or other resources has been commenced or completed.

ARTICLE 3. COMPENSATION FOR SERVICES

Section 3.1 Cost of Services. As compensation for any Services rendered to it pursuant to this Agreement, Client Company shall pay to Service Provider the Cost thereof, except to the extent otherwise required by Section 482 of the Internal Revenue Code. "Costs" means the sum of (i) direct costs, (ii) indirect costs and (iii) costs of capital. As soon as practicable after the close of each month, Service Provider shall render to each Client Company a statement reflecting the billing information necessary to identify the costs charged for that month. By the last day of each month, Client Company shall remit to Service Provider all charges billed to it. For avoidance of doubt, the Service Provider and each Client Company may satisfy the foregoing requirement by recording billings and payments required hereunder in their common accounting systems without rendering paper or electronic monthly statements or remitting cash payments.

Section 3.2 Exception. In the event any Services to be rendered under this Agreement are to be provided to or from DEC, DEP, and Piedmont in accordance with DEC's, DEP's, and Piedmont's North Carolina Code of Conduct at anything other than fully embedded cost as described above, then prior to entering into the transaction, DEI, DEK, DEF or DEO, whichever is applicable, shall provide 30 days written notice to the respective state commission staffs and state consumer representatives explaining the proposed transaction, including the benefits of the transaction. If no objection is received within 30 days, then the transaction may proceed. If one or more third parties object to the transaction in writing within 30 days, then DEI, DEK, DEF or DEO, whichever is applicable, must seek specific state commission approval of the transaction prior to entering into the transaction.

ARTICLE 4. LIMITATION OF LIABILITY; INDEMNIFICATION

Section 4.1 Limitation of Liability/Services. In performing Services pursuant to Section 1.1 hereof, Service Provider will exercise due care to assure that the Services are performed in a workmanlike manner in accordance with the specifications set forth in the applicable Service Request and consistent with any applicable legal standards. The sole and exclusive responsibility of Service Provider for any deficiency therein shall be promptly to correct or repair such deficiency or to re-perform such Services, in either case at no additional cost to Client Company, so that the Services fully conform to the standards described in the first sentence of this Section 4.1. No Service Provider makes any other warranty with respect to the provision of Services, and each Client Company agrees to accept any Services without further warranty of any nature.

Section 4.2 Limitation of Liability/Loaned Employees. In furnishing Services under Section 1.2 hereof (*i.e.*, involving loaned employees), neither the Service Provider, nor any officer, director, employee or agent thereof, shall have any responsibility whatsoever to any Client Company receiving such Services, and Client Company specifically releases Service Provider and such persons, on account of any claims, liabilities, injuries, damages or other consequences arising in connection with the provision of such Services under any theory of liability, whether in contract, tort (including negligence or strict liability) or otherwise, it being understood and agreed that any such loaned employees are made available without warranty as to their suitability or expertise.

Section 4.3 Disclaimer. WITH RESPECT TO ANY SERVICES PROVIDED UNDER THIS AGREEMENT, THE SERVICE PROVIDER THEREOF MAKES NO WARRANTY OR REPRESENTATION OTHER THAN AS SET FORTH IN SECTION 4.1, AND THE PARTIES HERETO HEREBY AGREE THAT NO OTHER WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE), SHALL BE APPLICABLE TO THE PROVISION OF ANY SUCH SERVICES. THE PARTIES FURTHER AGREE THAT THE REMEDIES STATED HEREIN ARE EXCLUSIVE AND SHALL CONSTITUTE THE SOLE AND EXCLUSIVE REMEDY OF ANY PARTY HERETO FOR A FAILURE BY ANY OTHER PARTY HERETO TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

Section 4.4 Indemnification.

(a) Subject to subparagraph (b) of this Section 4.4, Service Provider shall release, defend, indemnify and hold harmless each Client Company, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any loss, liability, claim, damage, expense (including costs of investigation and defense and reasonable attorneys' fees), whether or not involving a third-party claim, incurred or sustained by or against any such Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services.

(b) Notwithstanding any other provision hereof, Service Provider's total liability hereunder with respect to any specific Services shall be limited to the amount actually paid to Service Provider for its performance of the specific Services for which the liability arises, and under no circumstances shall Service Provider be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

Section 4.5 Procedure for Indemnification. Within 15 business days after receipt by any Client Company of notice of any claim or the commencement of any action, suit, litigation or other proceeding against it (a "Proceeding") with respect to which it is eligible for indemnification hereunder, such Client Company shall notify Service Provider thereof in writing (it being understood that failure to so notify Service Provider shall not relieve the latter of its indemnification obligation, unless Service Provider establishes that defense thereof has been prejudiced by such failure). Thereafter, Service Provider shall be entitled to participate in such Proceeding and, at its election upon notice to such Client Company and at its expense, to assume the defense of such Proceeding. Without the prior written consent of such Client Company, Service Provider shall not enter into any settlement of any third-party claim that would lead to liability or create any financial or other obligation on the part of such Client Company for which such Client Company is not entitled to indemnification hereunder. If such Client Company has given timely notice to Service Provider of the commencement of such Proceeding, but Service Provider has not, within 15 business days after receipt of such notice, given notice to Client Company of its election to assume the defense thereof, Service Provider shall be bound by any determination made in such Proceeding or any compromise or settlement made by Client Company. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice from the applicable Client Company to Service Provider.

ARTICLE 5. MISCELLANEOUS

Section 5.1 Amendments. Any amendments to this Agreement shall be in writing executed by each of the parties hereto. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any affected state public utility commission for its review or otherwise, each Operating Company shall comply in all respects with any such requirements.

Section 5.2 Effective Date; Term. This Agreement shall become effective on the Effective Date and shall continue in full force and effect as to each party until terminated by any party, as to itself only, upon not less than 30 days prior written notice to the other parties hereto. Any such termination of parties shall not be deemed an amendment hereto. This Agreement may be terminated and thereafter be of no further force and effect upon the mutual consent of all of the parties hereto.

Section 5.3 Entire Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto. Any oral or written statements, representations, promises, negotiations or agreements, whether prior hereto or concurrently herewith, are superseded by and merged into this Agreement.

Section 5.4 Severability. If any provision of this Agreement or any application thereof shall be determined to be invalid or unenforceable, the remainder of this Agreement and any other application thereof shall not be affected thereby.

Section 5.5 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of each of the other parties. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 5.6 Governing Law. This Agreement shall be construed and enforced under and in accordance with the laws of the State of New York, without regard to conflicts of laws principles.

Section 5.7 Captions, Headings. The captions and headings used in this Agreement are for convenience of reference only and shall not affect the construction to be accorded any of the provisions hereof. As used in this Agreement, "hereof," "hereunder," "herein," "hereto," and words of like import refer to this Agreement as a whole and not to any particular section or other paragraph or subparagraph thereof.

Section 5.8 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed a duplicate original hereof, but all of which shall be deemed one and the same Agreement.

Section 5.9 DEC, DEP, and Piedmont Conditions. In addition to the terms and conditions set forth herein, with respect to DEC, DEP, and Piedmont, the provisions set out in Appendix B are hereby incorporated herein by reference. In addition, except with respect to the pricing of Services as set forth herein, DEC's, DEP's and Piedmont's participation in this Agreement is explicitly subject to the Regulatory Conditions and Code of Conduct approved by the North Carolina Utilities Commission ("NCUC") in its *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct* issued, in Docket Nos. E-2, Sub 1095 and E-7, Sub 1100, and G-9, Sub 682, and applicable to South Carolina, as such Regulatory Conditions and Code of Conduct may be amended from time to time. In the event of any conflict between the provisions of this Agreement and the approved Regulatory Conditions and Code of Conduct provisions, the Regulatory Conditions and Code of Conduct shall govern.

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on _________, 201_, on its behalf by an appropriate officer thereunto duly authorized.

Duke Energy Carolinas, LLC

By: ________________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Ohio, Inc.

By: ________________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Indiana, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Kentucky, Inc.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Progress, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Florida, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Piedmont Natural Gas Company, Inc.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

eForms

Folder Name: efr148v1-003818
Status: New

Service Request for Affiliates

* Red Asterisk indicates required fields   * Functional Area (for the Service Provider):

Service Provider

* Service Provider [Select]

*Legal Approval Representative [Select]

Proposed Service

* Description of Proposed Service

Please Provide Basis for Estimated Costs, include # of employees requested and amount of time requested

* Estimated Costs (Numbers only, no commas or decimals) $0

* Scheduled Start Date

* Scheduled Completion Date

Client Company

* Client Company [Select]

PeopleSoft Accounting Codes for the Services Provided

*** Process OR Project & Activities OR GL Account for Client Company must be entered

* Client Company Operating Unit   * Service Provider Resp. Center   * Process

* Project   * Activity   * GL Account

Confirmation of Service Provider Utility Responsibilities by Service Provider Approver

* ☐ Check this box to confirm that this Service Request will not result in impairment of Service Provider's utility responsibilities or business operations.

Confirmation of Service Provider Utility Responsibilities by Service Provider Approver

* ☐ Check this box to confirm that this Service Request will not result in impairment of Service Provider's utility responsibilities or business operations.

Miscellaneous Comments

Comments

Comments Log

Attachments

Help

Filename	Size

Approver Selection

The approvers should be appropriate according to the Delegation of Authority (DOA) matrix.

Route To:	Name		Phone	Status
* Client Company		Select		
* Service Provider		Select		
* Legal				

Submitter Details

Created by		Created on	11/10/2015 1:19:43 PM
* Phone			
Last Modified by		Last Modified	

Exhibit B

DUKE ENERGY CAROLINAS, LLC DUKE ENERGY PROGRESS, LLC, AND PIEDMONT NATURAL GAS COMPANY, INC. CONDITIONS

1. In connection with the NCUC approval of the Merger in NCUC Docket No. E-2, Sub 1095, Docket No. E-7, Sub 1100, and Docket No. G-5, Sub 682, the NCUC adopted certain Regulatory Conditions and a revised Code of Conduct governing transactions between DEC, DEP, Piedmont, and their affiliates. Pursuant to the Regulatory Conditions, the following provisions are applicable to DEC, DEP, and Piedmont:

(a) DEC's, DEP's and Piedmont's participation in this Agreement is voluntary. DEC, DEP, or Piedmont is not obligated to take or provide services or make any purchases or sales pursuant to this Agreement, and DEC, DEP, or Piedmont may elect to discontinue its participation in this Agreement at its election after giving any required notice;

(b) DEC, DEP or Piedmont may not make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder.

(c) DEC, DEP or Piedmont may not seek to reflect in rates any (A) costs incurred under this Agreement exceeding the amount allowed by the NCUC or (B) revenue level earned under this Agreement less than the amount imputed by the NCUC; and

(d) DEC, DEP or Piedmont shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of other entity's assertions, that the NCUC's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is, in whole or in part, (A) preempted by Federal Law or (B) not within the Commission's power, authority, or jurisdiction; DEC, DEP, and Piedmont will bear the full risk of any preemptive effects of Federal Law with respect to this Agreement.

2. Transfers by DEC, DEP, or Piedmont. With respect to the transfer by DEC, DEP, or Piedmont under this Agreement of the control of, operational responsibility for, or ownership of any DEC, DEP, or Piedmont assets used for the generation, transmission or distribution of electric power to its North Carolina retail customers with a gross book value in excess of ten million dollars, the following shall apply: (a) neither DEC, DEP nor Piedmont may commit to or carry out the transfer except in accordance with all applicable law, and the rules, regulations and orders of the NCUC promulgated thereunder; and (b) neither DEC, DEP, or Piedmont may include in its North Carolina cost of service or rates the value of the transfer, whether or not subject to federal law, except as allowed by the NCUC in accordance with North Carolina law.

3. Access to DEC, DEP or Piedmont Information. Any Operating Company providing Services to DEC or DEP pursuant to this Agreement, including any loaned employees under Section 1.2 of the Agreement, shall be permitted to have access to DEC's, DEP's or Piedmont's Customer Information and Confidential Systems Operation Information, as those terms are defined in the Code of Conduct, to the extent necessary for the performance of such Services; provided that such Operating Company shall take reasonable steps to protect the confidentiality of such Information.

Exhibit B

4. Procedures for Services Received By DEC DEP, or Piedmont from each other or the other Operating Companies and for Services Provided by DEC, DEP or Piedmont to each other or the other Operating Companies. DEC, DEP, and Piedmont shall receive from each other and the other Operating Companies, upon the terms and conditions set forth in this agreement, such of the services listed in the Operating Companies Service Agreement List on file with the NCUC, at such times, for such periods and in such manner as DEC DEP, or Piedmont may from time to time request of each other or another Operating Company. DEC, DEP, or Piedmont may provide to each other and the other Operating Companies, upon the terms and conditions set forth in this Agreement, at such times for such periods, and in such a manner as DEC, DEP or Piedmont concludes it is equipped to perform for each other or another Operating Company. DEC, DEP, or Piedmont may perform these services for each other as described in this paragraph without the requirement of a written request in substantially the form attached to this Agreement as Exhibit A.

AMENDED AND RESTATED OPERATING COMPANY/NONUTILITY COMPANIES SERVICE AGREEMENT

This Amended and Restated Operating Company/Nonutility Companies Service Agreement (this "Agreement") dated September 1, 2008 (the "Effective Date") by and among Duke Energy Kentucky, Inc., a Kentucky corporation ("Operating Company"), and the respective associate nonutility companies listed on the signature pages hereto (each, a "Nonutility Company") supersedes and restates in its entirety the Operating Company/Nonutility Service Agreement entered into between the Operating Company and each Nonutility Company dated January 2, 2007.

WITNESSETH:

WHEREAS, Duke Energy Corporation ("Duke Energy") is a Delaware corporation;

WHEREAS, Operating Company is a subsidiary of Duke Energy and a public utility company;

WHEREAS, each Nonutility Company is a subsidiary of Duke Energy that is or was formed to engage in any one or more non-regulated businesses;

WHEREAS, certain non-regulated public utilities were added in error to the Operating Company/Nonutility Companies Service Agreement dated January 2, 2007 and are being removed in this Agreement;

WHEREAS, in the ordinary course of their businesses, Operating Company and each Nonutility Company maintain organizations of employees with technical expertise in matters affecting public utility companies and related businesses and own or acquire related equipment, facilities, properties and other resources; and

WHEREAS, subject to the terms and conditions herein set forth, and taking into consideration the parties' utility responsibilities or primary business operations, as the case may be, the parties hereto are willing, upon request from time to time, to perform such services, and in connection therewith to make available such equipment, facilities, properties and other resources, as they shall request from each other;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1. PROVISION OF SERVICES; LOANED EMPLOYEES

Section 1.1 Provision of Services.

(a) Upon receipt by a party hereto (in such capacity, a "Service Provider") of a written request in substantially the form attached hereto as Exhibit A (a "Service Request") from another party hereto (in such capacity, a "Client Company") for the provision to such Client Company of such services as are specified therein, including if applicable use of any related equipment, facilities, properties or other resources (collectively, "Services"), the Service Provider, if in its sole discretion it has available the personnel or other resources needed to perform the Service Request without impairment of its utility responsibilities or business operations, as the case may be, shall furnish such Services to the Client Company at such times, for such periods and in such manner as the Client Company shall have so requested and otherwise in accordance with the provisions hereof.

(b) For purposes of this Agreement, "Services" may include, but shall not be limited to: (i) in the case of Services that may be provided by Operating Company hereunder, services in such areas as engineering and construction; operations and maintenance; installation services; equipment testing; generation technical support; environmental, health and safety; and procurement services;[1] and (ii) in the case of Services that may be provided by Nonutility Companies hereunder, services in such areas as information technology services; monitoring, surveying, inspecting, constructing, locating and marking of overhead and underground utility facilities; meter reading; materials management; vegetation management; and marketing and customer relations.

(c) For the avoidance of doubt, affiliate transactions involving sales or other transfers of assets, goods, energy commodities (including electricity, natural gas, coal and other combustible fuels) or thermal energy products are outside the scope of this Agreement.

Section 1.2 Loaned Employees.

(a) If specifically requested in connection with the provision of Services, Service Provider shall loan one or more of its employees to such Client Company, provided that such loan shall not, in the sole discretion of Service Provider, interfere with or impair Service Provider's utility responsibilities or business operations, as the case may be. After the commencement thereof, any such loaned employees may be withdrawn by Service Provider from tasks duly assigned by Client Company, prior to completion thereof as contemplated in the associated Service Request, only with the consent of Client Company (which shall not be unreasonably withheld or delayed), except in the event of a demonstrable emergency requiring the use of any such employees in another capacity for Service Provider.

(b) While performing work on behalf of Client Company, any such loaned employees shall be under its supervision and control, and Client Company shall be responsible for their actions to the same extent as though such persons were its employees (it being understood that such persons shall nevertheless remain employees of Service Provider and nothing herein shall be construed as creating an employer-employee relationship between any Client Company and any loaned employees). Accordingly, for the duration of any such loan, Service Provider shall continue to provide its loaned employees with the same payroll, pension, savings, tax withholding, unemployment, bookkeeping and other personnel support services then being provided by Service Provider to its other employees.

ARTICLE 2. SERVICE REQUESTS

Section 2.1 Procedure. All Services (including any loans of employees) (i) shall be performed in accordance with Service Requests issued by or on behalf of Client Company and accepted by Service Provider and (ii) shall be assigned to applicable activities, processes, projects, responsibility centers or on other appropriate bases to enable specific work to be properly assigned. Service Requests shall be as specific as practicable in defining the Services requested. Client Company shall have the right from time to time to amend or rescind any Service Request, *provided* that (a) Service Provider consents to any amendment that results in a material change in the scope of Services to be provided, (b) the costs associated with an amended or rescinded Service Request shall include the costs incurred by Service Provider as a result of such amendment or rescission, and (c) no amendment or rescission of a Service Request shall release Client Company from any liability for costs already incurred or contracted for by Service Provider pursuant to the original Service Request, regardless of whether any labor or the furnishing of any property or other resources has been commenced or completed.

ARTICLE 3. COMPENSATION FOR SERVICES

Section 3.1 Cost of Services. As compensation for any Services rendered to it pursuant to this Agreement, Client Company shall pay to Service Provider the fully embedded cost thereof (i.e., the sum of (i) direct costs, (ii) indirect costs and (iii) costs of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code. As soon as practicable after the close of each month, Service Provider shall render to each Client Company a statement reflecting the billing information necessary to identify the costs charged for that month. By the last day of each month, Client Company shall remit to Service Provider all charged billed to it.

ARTICLE 4. LIMITATION OF LIABILITY; INDEMNIFICATION

Section 4.1 Limitation of Liability/Services. In performing Services pursuant to Section 1.1 hereof, Service Provider will exercise due care to assure that the Services are performed in a workmanlike manner in accordance with the specifications set forth in the applicable Service Request and consistent with any applicable legal standards. The sole and exclusive responsibility of Service Provider for any deficiency therein shall be promptly to correct or repair such deficiency or to re-perform such Services, in either case at no additional cost to Client Company, so that the Services fully conform to the standards described in the first sentence of this Section 4.1. No Service Provider makes any other warranty with respect to the provision of Services, and each Client Company agrees to accept any Services without further warranty of any nature.

Section 4.2 Limitation of Liability/Loaned Employees. In furnishing Services under Section 1.2 hereof (i.e., involving loaned employees), neither the Service Provider, nor any officer, director, employee or agent thereof, shall have any responsibility whatever to any Client Company receiving such Services, and Client Company specifically releases Service Provider and such persons, on account of any claims, liabilities, injuries, damages or other consequences arising in connection with the provision of such Services under any theory of liability, whether in contract, tort (including negligence or strict liability) or otherwise, it being understood and agreed that any such loaned employees are made available without warranty as to their suitability or expertise.

Section 4.3 Disclaimer. WITH RESPECT TO ANY SERVICES PROVIDED UNDER THIS AGREEMENT, THE SERVICE PROVIDER THEREOF MAKES NO WARRANTY OR REPRESENTATION OTHER THAN AS SET FORTH IN SECTION 4.1, AND THE PARTIES HERETO HEREBY AGREE THAT NO OTHER WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE), SHALL BE APPLICABLE TO THE PROVISION OF ANY SUCH SERVICES. THE PARTIES FURTHER AGREE THAT THE REMEDIES STATED HEREIN ARE EXCLUSIVE AND SHALL CONSTITUTE THE SOLE AND EXCLUSIVE REMEDY OF ANY PARTY HERETO FOR A FAILURE BY ANY OTHER PARTY HERETO TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

Section 4.4 Indemnification.

(a) Indemnification In Respect of Services Provided by Operating Company.

(i) In circumstances where Operating Company is a Service Provider: (x) subject to subparagraph (ii) of this Section 4.4(a), Service Provider shall release, defend, indemnify and hold harmless each Client Company, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any loss, liability, claim, damage, expense (including costs of investigation and defense and reasonable attorneys' fees), whether or not involving a third-party claim (collectively, "Damages"), incurred or sustained by or against Service Provider or any such Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services, and (y) each Nonutility Company that is a Client Company with respect to such Services shall release, defend, indemnify and hold harmless Service Provider, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any Damages incurred or sustained by or against Service Provider or any such Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services, to the extent such Damages are not covered by Service Provider's indemnification obligation as provided in the preceding clause (x) or exceed the liability limits provided in subparagraph (ii) of this Section 4.4(a).

(ii) Notwithstanding any other provision hereof, in circumstances where Operating Company is a Service Provider: (x) Service Provider's total liability hereunder with respect to any specific Services shall be limited to the amount actually paid to Service Provider for its performance of the specific Services for which the liability arises, and (y) under no circumstances shall Service Provider be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

(b) Indemnification In Respect of Services Provided by Any Nonutility Company.

(i) In circumstances where a Nonutility Company is a Service Provider (*i.e.*, where Operating Company is the Client Company): (x) subject to subparagraph (ii) of this Section 4.4(b), Service Provider shall release, defend, indemnify and hold harmless the Client Company, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any Damages incurred or sustained by or against Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services.

(ii) Notwithstanding any other provision hereof, in circumstances where a Nonutility Company is a Service Provider (*i.e.*, where Operating Company is the Client Company), under no circumstances shall Service Provider be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

Section 4.5 <u>Procedure for Indemnification</u>. Within 15 business days after receipt by any Client Company of notice of any claim or the commencement of any action, suit, litigation or other proceeding against it (a "Proceeding") with respect to which it is eligible for indemnification hereunder, such Client Company shall notify Service Provider thereof in writing (it being understood that failure so to notify Service Provider shall not relieve the latter of its indemnification obligation, unless Service Provider establishes that defense thereof has been prejudiced by such failure). Thereafter, Service Provider shall be entitled to participate in such Proceeding and, at its election upon notice to such Client Company and at its expense, to assume the defense of such Proceeding. Without the prior written consent of such Client Company, Service Provider shall not enter into any settlement of any third-party claim that would lead to liability or create any financial or other obligation on the part of such Client Company for which it such Client Company is not entitled to indemnification hereunder. If such Client Company has given timely notice to Service Provider of the commencement of such Proceeding, but Service Provider has not, within 15 business days after receipt of such notice, given notice to Client Company of its election to assume the defense thereof, Service Provider shall be bound by any determination made in such Proceeding or any compromise or settlement made by Client Company. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice from the applicable Client Company to Service Provider.

ARTICLE 5. MISCELLANEOUS

Section 5.1 <u>Amendments.</u> Any amendments to this Agreement shall be in writing executed by each of the parties hereto. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with the Kentucky Public Service Commission for its review or otherwise, Operating Company shall comply in all respects with any such requirements.

Section 5.2 <u>Effective Date; Term</u>. This Agreement shall become effective on the Effective Date and shall continue in full force and effect as to each party until terminated by any party, as to itself only, upon not less than 30 days prior written notice to the other parties hereto. Any such

Any such termination of parties shall not be deemed an amendment hereto. This Agreement may be terminated and thereafter be of no further force and effect upon the mutual consent of all of the parties hereto.

Section 5.3 Additional Parties. After the effective date of this Agreement, additional Nonutility Companies may become parties to this Agreement by executing appropriate signature pages, whereupon any such additional signatory shall be deemed a "party" hereto all purposes hereof and shall thereupon become bound by the terms and conditions of this Agreement as if an original party hereto. The addition of any such further signatories, in the absence of any changes to the terms of this Agreement, shall not be deemed an amendment hereto.

Section 5.4 Entire Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto (including that certain Services Agreement between Operating Company and certain nonutility subsidiaries of Duke Energy dated April 3, 2006). Any oral or written statements, representations, promises, negotiations or agreements, whether prior hereto or concurrently herewith, are superseded by and merged into this Agreement.

Section 5.5 Severability. If any provision of this Agreement or any application thereof shall be determined to be invalid or unenforceable, the remainder of this Agreement and any other application thereof shall not be affected thereby.

Section 5.6 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of each of the other parties. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 5.7 Governing Law. This Agreement shall be construed and enforced under and in accordance with the laws of the State of Kentucky, without regard to conflicts of laws principles.

Section 5.8 Captions, etc. The captions and headings used in this Agreement are for convenience of reference only and shall not affect the construction to be accorded any of the provisions hereof. As used in this Agreement, "hereof," "hereunder," "herein," "hereto," and words of like import refer to this Agreement as a whole and not to any particular section or other paragraph or subparagraph thereof.

Section 5.9 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed a duplicate original hereof, but all of which shall be deemed one and the same Agreement.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on its behalf by an appropriate officer thereunto duly authorized.

DUKE ENERGY KENTUCKY, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY CORP.

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY INVESTMENTS, INC.

By:______________________________
George Dwight, II
Assistant Secretary

KO TRANSMISSION COMPANY

By:______________________________
Richard G. Beach
Assistant Secretary

TRI-STATE IMPROVEMENT COMPANY

By:______________________________
Richard G. Beach
Assistant Secretary

SOUTH CONSTRUCTION COMPANY, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

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By:______________________________
Richard G. Beach
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SOUTH CONSTRUCTION COMPANY, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

CINPOWER I, LLC

By: R. G. Beach

Richard G. Beach
Assistant Secretary

DUKE ENERGY ENGINEERING, INC.

By:____________________________

George Dwight, II
Assistant Secretary

DUKE ENERGY GENERATION SERVICES
HOLDING COMPANY, INC.

By:____________________________

George Dwight, II
Assistant Secretary

SUEZ-DEGS, LLC

By:____________________________

David A. Ledonne
Vice President

SUEZ-DEGS OF ORLANDO, LLC

By:____________________________

George Dwight, II
Assistant Secretary

DUKE-RELIANT RESOURCES, INC.

By: R. G. Beach

Richard G. Beach
Assistant Secretary

CINPOWER I, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY ENGINEERING, INC.

By: George Dwight
George Dwight, II
Assistant Secretary

DUKE ENERGY GENERATION SERVICES HOLDING COMPANY, INC.

By: George Dwight
George Dwight, II
Assistant Secretary

SUEZ-DEGS, LLC

By:______________________________
David A. Ledonne
Vice President

SUEZ-DEGS OF ORLANDO, LLC

By: George Dwight
George Dwight, II
Assistant Secretary

DUKE-RELIANT RESOURCES, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

CINPOWER I, LLC

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Richard G. Beach
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By:______________________________
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David A. Ledonne
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By:______________________________
George Dwight, II
Assistant Secretary

DUKE-RELIANT RESOURCES, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

RELIANT SERVICES, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY TECHNOLOGY, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

DEGS OF TUSCOLA, INC.

By:______________________________
George Dwight, II
Assistant Secretary

ENERGY EQUIPMENT LEASING LLC

By:______________________________
George Dwight, II
Assistant Secretary

DEGS OF BOCA RATON, LLC

By:______________________________
George Dwight, II
Assistant Secretary

DEGS OF CINCINNATI, LLC

By:______________________________
George Dwight, II
Assistant Secretary

RELIANT SERVICES, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY TECHNOLOGY, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

DEGS OF TUSCOLA, INC.

By: George Dwight
George Dwight, II
Assistant Secretary

ENERGY EQUIPMENT LEASING LLC

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DEGS OF BOCA RATON, LLC

By: George Dwight
George Dwight, II
Assistant Secretary

DEGS OF CINCINNATI, LLC

By: George Dwight
George Dwight, II
Assistant Secretary

DEGS OF ST. PAUL, LLC

By:________________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF TUSCOLA, LLC

By:________________________________
George Dwight, II
Assistant Secretary

DEGS BIOGAS, INC.

By:________________________________
George Dwight, II
Assistant Secretary

DEGS GASCO, LLC

By:________________________________
George Dwight, II
Assistant Secretary

DUKE ENERGY ONE, INC.

By:________________________________
Richard G. Beach
Assistant Secretary

CINERGY POWER GENERATION SERVICES, LLC

By:________________________________
Joseph E. Lentz, Jr.
Vice President

DEGS OF ST. PAUL, LLC

By:______________________________
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By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY POWER GENERATION SERVICES, LLC

By:______________________________
Joseph E. Lentz, Jr.
Vice President

DUKE ENERGY GENERATION SERVICES, INC.

By:____________________________
George Dwight, II
Assistant Secretary

DUKE TECHNOLOGIES, INC.

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE VENTURES II, LLC

By:____________________________
Richard G. Beach
Assistant Secretary

CINERGY WHOLESALE ENERGY, INC.

By:____________________________
Joseph E. Lentz, Jr.
Vice President

DUKETEC, LLC

By:____________________________
Richard G. Beach
Assistant Secretary

DUKETEC I, LLC

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY GENERATION SERVICES, INC.

By:______________________________
George Dwight, II
Assistant Secretary

DUKE TECHNOLOGIES, INC.

By: R. J. Beal
Richard G. Beach
Assistant Secretary

DUKE VENTURES II, LLC

By: R. J. Beal
Richard G. Beach
Assistant Secretary

CINERGY WHOLESALE ENERGY, INC.

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Joseph E. Lentz, Jr.
Vice President

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Richard G. Beach
Assistant Secretary

DUKETEC I, LLC

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DUKE ENERGY GENERATION SERVICES, INC.

By:________________________________
George Dwight, II
Assistant Secretary

DUKE TECHNOLOGIES, INC.

By:________________________________
Richard G. Beach
Assistant Secretary

DUKE VENTURES II, LLC

By:________________________________
Richard G. Beach
Assistant Secretary

CINERGY WHOLESALE ENERGY, INC.

By:________________________________
Joseph E. Lentz, Jr.
Vice President

DUKETEC, LLC

By:________________________________
Richard G. Beach
Assistant Secretary

DUKETEC I, LLC

By:________________________________
Richard G. Beach
Assistant Secretary

EVENT RESOURCES I LLC

By:________________________________
Richard G. Beach
Assistant Secretary

LANSING GRAND RIVER UTILITIES, LLC

By:________________________________
George Dwight, II
Assistant Secretary

OKLAHOMA ARCADIAN UTILITIES, LLC

By:________________________________
George Dwight, II
Assistant Secretary

SHREVEPORT RED RIVER UTILITIES, LLC

By:________________________________
George Dwight, II
Assistant Secretary

SYNCAP II, LLC

By:________________________________
George Dwight, II
Assistant Secretary

SUEZ/VWNA/DEGS OF LANSING, LLC

By:________________________________
George Dwight, II
Assistant Secretary

EVENT RESOURCES I LLC

By:______________________________
Richard G. Beach
Assistant Secretary

LANSING GRAND RIVER UTILITIES, LLC

By:______________________________
George Dwight, II
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By:______________________________
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By:______________________________
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Assistant Secretary

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By:______________________________
George Dwight, II
Assistant Secretary

SUEZ/VWNA/DEGS OF LANSING, LLC

By:______________________________
George Dwight, II
Assistant Secretary

BSPE, L.P.

By:________________________
Wouter T. van Kempen
Authorized Representative

BSPE GENERAL, LLC

By:________________________
Wouter T. van Kempen
Authorized Representative

BSPE HOLDINGS, LLC

By:________________________
Wouter T. van Kempen
Authorized Representative

BSPE LIMITED, LLC

By:________________________
Wouter T. van Kempen
Authorized Representative

CSGP OF SOUTHEAST TEXAS, LLC

By:________________________
George Dwight, II
Assistant Secretary

OWINGS MILLS ENERGY EQUIPMENT LEASING LLC

By:________________________
George Dwight, II
Assistant Secretary

BSPE, L.P.

By:______________________________
Wouter T. van Kempen
Authorized Representative

BSPE GENERAL, LLC

By:______________________________
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BSPE HOLDINGS, LLC

By:______________________________
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BSPE LIMITED, LLC

By:______________________________
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CSGP OF SOUTHEAST TEXAS, LLC

By:______________________________
George Dwight, II
Assistant Secretary

OWINGS MILLS ENERGY EQUIPMENT LEASING LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF OWINGS MILLS, LLC

By:____________________________
George Dwight, II
Assistant Secretary

CST LIMITED, LLC

By:____________________________
George Dwight, II
Assistant Secretary

CST GENERAL, LLC

By:____________________________
George Dwight, II
Assistant Secretary

CSGP LIMITED, LLC

By:____________________________
George Dwight, II
Assistant Secretary

CSGP SERVICES, L.P.
(by CSGP General, LLC its General Partner)

By:____________________________
George Dwight, II
Assistant Secretary

CSGP GENERAL, LLC

By:____________________________
George Dwight, II
Assistant Secretary

CINERGY GLOBAL TRADING LIMITED

By: Julia S. Janson

Julia S. Janson
Secretary

CINERGY ORIGINATION & TRADE, LLC

By:______________________________

Richard G. Beach
Assistant Secretary

DEGS OF PHILADELPHIA, LLC

By:______________________________

George Dwight, II
Assistant Secretary

OHIO RIVER VALLEY PROPANE, LLC

By: Julia S. Janson

Julia S. Janson
Secretary

CINERGY RETAIL POWER LIMITED, INC.

By:______________________________

Richard G. Beach
Assistant Secretary

CINERGY RETAIL POWER GENERAL, INC.

By:______________________________

Joseph E. Lentz, Jr.
Vice President

CINERGY GLOBAL TRADING LIMITED

By:______________________________
Julia S. Janson
Secretary

CINERGY ORIGINATION & TRADE, LLC

By: R. G. Beach
Richard G. Beach
Assistant Secretary

DEGS OF PHILADELPHIA, LLC

By:______________________________
George Dwight, II
Assistant Secretary

OHIO RIVER VALLEY PROPANE, LLC

By:______________________________
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CINERGY RETAIL POWER LIMITED, INC.

By: R. G. Beach
Richard G. Beach
Assistant Secretary

CINERGY RETAIL POWER GENERAL, INC.

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Joseph E. Lentz, Jr.
Vice President

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George Dwight, II
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CINERGY RETAIL POWER LIMITED, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY RETAIL POWER GENERAL, INC.

By:______________________________
Joseph E. Lentz, Jr.
Vice President

CINERGY RETAIL POWER, L.P.
(by Cinergy Retail Power General, Inc. its General Partner)

By:______________________________
Joseph E. Lentz, Jr.
Vice President

DELTA TOWNSHIP UTILITIES, LLC

By:______________________________
George Dwight, II
Assistant Secretary

CINERGY LIMITED HOLDINGS, LLC

By:______________________________
Greer E. Mendelow
Assistant Secretary

CINERGY GENERAL HOLDINGS, LLC

By:______________________________
Julia S. Janson
Secretary

CINERGY RECEIVABLES COMPANY LLC

By:______________________________
Richard G. Beach
Secretary

CINFUEL RESOURCES, INC.

By:______________________________
George Dwight, II
Assistant Secretary

CINERGY RETAIL POWER, L.P.
(by Cinergy Retail Power General, Inc. its General Partner)

By:______________________________
Joseph E. Lentz, Jr.
Vice President

DELTA TOWNSHIP UTILITIES, LLC

By: George Dwight
George Dwight, II
Assistant Secretary

CINERGY LIMITED HOLDINGS, LLC

By:______________________________
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Assistant Secretary

CINERGY GENERAL HOLDINGS, LLC

By:______________________________
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Secretary

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George Dwight, II
Assistant Secretary

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(by Cinergy Retail Power General, Inc. its General Partner)

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CINERGY RECEIVABLES COMPANY LLC

By:______________________________
Richard G. Beach
Secretary

CINFUEL RESOURCES, INC.

By:______________________________
George Dwight, II
Assistant Secretary

LH1, LLC

By:______________________
George Dwight, II
Assistant Secretary

OAK MOUNTAIN PRODUCTS, LLC

By:______________________
George Dwight, II
Assistant Secretary

DEGS OF LANSING, LLC

By:______________________
George Dwight, II
Assistant Secretary

DEGS OF SHREVEPORT, LLC

By:______________________
George Dwight, II
Assistant Secretary

DEGS OF OKLAHOMA, LLC

By:______________________
George Dwight, II
Assistant Secretary

DEGS OF NARROWS, LLC

By:______________________
George Dwight, II
Assistant Secretary

DEGS OF ROCK HILL, LLC

By: ______________________________
George Dwight, II
Assistant Secretary

DEGS OF ST. BERNARD, LLC

By: ______________________________
George Dwight, II
Assistant Secretary

CINERGY CLIMATE CHANGE INVESTMENTS, LLC

By: ______________________________
Richard G. Beach
Assistant Secretary

DEGS OF MONACA, LLC

By: ______________________________
George Dwight, II
Assistant Secretary

DUKETEC II, LLC

By: ______________________________
Richard G. Beach
Assistant Secretary

DEGS OF SAN DIEGO, INC.

By: ______________________________
George Dwight, II
Assistant Secretary

DEGS OF ROCK HILL, LLC

By:____________________________
George Dwight, II
Assistant Secretary

DEGS OF ST. BERNARD, LLC

By:____________________________
George Dwight, II
Assistant Secretary

CINERGY CLIMATE CHANGE INVESTMENTS, LLC

By: R. G. Beach
Richard G. Beach
Assistant Secretary

DEGS OF MONACA, LLC

By:____________________________
George Dwight, II
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DUKETEC II, LLC

By: R. G. Beach
Richard G. Beach
Assistant Secretary

DEGS OF SAN DIEGO, INC.

By:____________________________
George Dwight, II
Assistant Secretary

DEGS OF SOUTH CHARLESTON, LLC

By:______________________________
George Dwight, II
Assistant Secretary

CINERGY SOLUTIONS – UTILITY, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

DEGS O&M, LLC

By:______________________________
George Dwight, II
Assistant Secretary

DELTA TOWNSHIP UTILITIES II, LLC

By:______________________________
George Dwight, II
Assistant Secretary

ENVIRONMENTAL WOOD SUPPLY, LLC

By:______________________________
David A. Ledonne
Vice President

DEGS OF DELTA TOWNSHIP, LLC

By:______________________________
George Dwight, II
Assistant Secretary

DEGS OF SOUTH CHARLESTON, LLC

By:______________________________
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Vice President

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By:______________________________
George Dwight, II
Assistant Secretary

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George Dwight, II
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Assistant Secretary

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By:______________________________
David A. Ledonne
Vice President

DEGS OF DELTA TOWNSHIP, LLC

By:______________________________
George Dwight, II
Assistant Secretary

DUKE BROADBAND, LLC

By: R. G. Beach

Richard G. Beach
Assistant Secretary

DUKE-CADENCE, INC.

By: R. G. Beach

Richard G. Beach
Assistant Secretary

CINERGY-CENTRUS, INC.

By: R. G. Beach

Richard G. Beach
Assistant Secretary

CINERGY-CENTRUS COMMUNICATIONS, INC.

By: R. G. Beach

Richard G. Beach
Assistant Secretary

DEGS EPCOM COLLEGE PARK, LLC

By:____________________________

George Dwight, II
Assistant Secretary

DUKE SUPPLY NETWORK, LLC

By: R. G. Beach

Richard G. Beach
Assistant Secretary

DUKE BROADBAND, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

DUKE-CADENCE, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

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By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY-CENTRUS COMMUNICATIONS, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

DEGS EPCOM COLLEGE PARK, LLC

By: George Dwight
George Dwight, II
Assistant Secretary

DUKE SUPPLY NETWORK, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY SOLUTIONS PARTNERS, LLC
(by Duke Energy Generation Services, Inc. its Managing Member)

By:______________________________
George Dwight, II
Assistant Secretary

DUKE COMMUNICATIONS HOLDINGS, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

CINERGY TWO, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

GREEN POWER G.P., LLC

By:______________________________
Wouter T. van Kempen
Authorized Representative

GREEN POWER HOLDINGS, LLC

By:______________________________
Wouter T. van Kempen
Authorized Representative

GREEN POWER LIMITED, LLC

By:______________________________
Wouter T. van Kempen
Authorized Representative

CINERGY SOLUTIONS PARTNERS, LLC
(by Duke Energy Generation Services, Inc. its Managing Member)

By:________________________________
George Dwight, II
Assistant Secretary

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Assistant Secretary

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Assistant Secretary

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Assistant Secretary

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Assistant Secretary

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GREEN POWER HOLDINGS, LLC

By:______________________________
Wouter T. van Kempen
Authorized Representative

GREEN POWER LIMITED, LLC

By:______________________________
Wouter T. van Kempen
Authorized Representative

SUEZ-DEGS OF ASHTABULA, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF LANSING, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF ROCHESTER, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF SILVER GROVE, LLC

By:______________________________
George Dwight, II
Assistant Secretary

DUKE ENERGY CORPORATION

By: R. G. Beach
Richard G. Beach
Assistant Corporate Secretary

BISON INSURANCE COMPANY LIMITED

By:______________________________
Edwin Keith Bone
Senior Vice President

SUEZ-DEGS OF ASHTABULA, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF LANSING, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF ROCHESTER, LLC

By:______________________________
George Dwight, II
Assistant Secretary

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By:______________________________
George Dwight, II
Assistant Secretary

DUKE ENERGY CORPORATION

By:______________________________
Richard G. Beach
Assistant Corporate Secretary

BISON INSURANCE COMPANY LIMITED

By:______________________________
George V. Brown
President and Chief Executive Officer

SUEZ-DEGS OF ASHTABULA, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF LANSING, LLC

By:______________________________
George Dwight, II
Assistant Secretary

SUEZ-DEGS OF ROCHESTER, LLC

By:______________________________
George Dwight, II
Assistant Secretary

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By:______________________________
George Dwight, II
Assistant Secretary

DUKE ENERGY CORPORATION

By:______________________________
Richard G. Beach
Assistant Corporate Secretary

BISON INSURANCE COMPANY LIMITED

By: George V. Brown
George V. Brown
President and Chief Executive Officer

DUKE ENERGY AMERICAS, LLC

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY GLOBAL MARKETS, INC.

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY ROYAL, LLC

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY INTERNATIONAL, LLC

By:____________________________
Javier Gonzalez
Assistant Secretary

DUKE ENERGY NORTH AMERICA, LLC

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE PROJECT SERVICES, INC.

By:____________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY AMERICAS, LLC

By:________________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY GLOBAL MARKETS, INC.

By:________________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY ROYAL, LLC

By:________________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY INTERNATIONAL, LLC

By: Javier Gonzalez
Javier Gonzalez
Assistant Secretary

DUKE ENERGY NORTH AMERICA, LLC

By:________________________________
Richard G. Beach
Assistant Secretary

DUKE PROJECT SERVICES, INC.

By:________________________________
Richard G. Beach
Assistant Secretary

DUKE VENTURES, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

CRESCENT RESOURCES, LLC

By:______________________________
Kay H. Arnette
Assistant Secretary

DUKENET COMMUNICATIONS, LLC

By:______________________________
Richard G. Beach
Assistant Secretary

PANENERGY CORP

By:______________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY SERVICES, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

DETMI MANAGEMENT, INC.

By:______________________________
Richard G. Beach
Assistant Secretary

DUKE ENERGY BUSINESS SERVICES LLC

By:______________________

Richard G. Beach
Assistant Secretary

DUKE ENERGY MERCHANTS, LLC

By:______________________

Richard G. Beach
Assistant Secretary

DUKE ENERGY RECEIVABLES FINANCE COMPANY, LLC

By:______________________

Richard G. Beach
Assistant Secretary

DUKENET COMMUNICATION SERVICES, LLC

By:______________________

Richard G. Beach
Assistant Secretary

Service Request Form

Please use this form for all service requests. All data fields are required.

Facilitator/Contact Information:

First Name:

Last Name:

Phone:

Email:

Service Provider: - Pull Down List to Select -

Or Other:
- Pull Down List to Select -

Service Provider Contact Information:

First Name:

Last Name:

Phone:

email Address of Service Provider Approver:

The approver should be appropriate according to the Expenditures, Divestitures & Terminations Category of the Delegation of Authority (DOA) matrix.

Description of Proposed Service and Please Provide Basis for Estimated Costs:

Client Company: - Pull Down List to Select -

Or Other:
- Pull Down List to Select -

Client Company Contact Information:

First Name:

Last Name:

Phone:

*(this e-mail address **must** be filled in properly for form to send automatically to the Client Approver)*

email Address of Client Company

The approver should be appropriate

Approver:	according to the Expenditures, Divestitures & Terminations Category of the Delegation of Authority (DOA) matrix.
Estimated Costs:	$ Format Numbers Only - do not include commas or periods
Scheduled Start Date:	MM/DD/YYYY
Scheduled Completion Date:	MM/DD/YYYY
Legal Approval Representative:	- Pull Down List to Select -

Accounting codes (FMIS / BDMS) of Duke Energy Company receiving the services:

Process / Work Code(s):

n/a / Corp. Number:

RCTo / Line of Business:

RCFrom / Center:

Project:

Activity:

Submit Reset

ASSYMMETRICALLY-PROCED DUKE ENERGY KENTUCKY, INC. /NONUTILITY COMPANIES SERVICE AGREEMENT

This Operating Company/Nonutility Companies Service Agreement (this "Agreement") is made and entered into as of October 1, 2009 (the "Effective Date") by and among Duke Energy Kentucky, Inc., a Kentucky corporation ("Operating Company"), and the respective associate nonutility companies listed on the signature pages hereto (each, a "Nonutility Company").

WITNESSETH:

WHEREAS, Duke Energy Corporation ("Duke Energy") is a Delaware corporation;

WHEREAS, Operating Company is a subsidiary of Duke Energy and a public utility company;

WHEREAS, each Nonutility Company is a subsidiary of Duke Energy that is or was formed to engage in any one or more non-regulated businesses;

WHEREAS, in the ordinary course of their businesses, Operating Company and each Nonutility Company maintain organizations of employees with technical expertise in matters affecting public utility companies and related businesses and own or acquire related equipment, facilities, properties and other resources; and

WHEREAS, subject to the terms and conditions herein set forth, and taking into consideration the parties' utility responsibilities or primary business operations, as the case may be, the parties hereto are willing, upon request from time to time, to perform such services, and in connection therewith to make available such equipment, facilities, properties and other resources, as they shall request from each other;

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1. PROVISION OF SERVICES; LOANED EMPLOYEES

Section 1.1 <u>Provision of Services</u>.

(a) Upon receipt by a party hereto (in such capacity, a "Service Provider") of a written request in substantially the form attached hereto as Exhibit A (a "Service Request") from another party hereto (in such capacity, a "Client Company") for the provision to such Client Company of such services as are specified therein, including if applicable use of any related equipment, facilities, properties or other resources (collectively, "Services"), the Service Provider, if in its sole discretion it has available the personnel or other resources needed to perform the Service Request without impairment of its utility responsibilities or business operations, as the case may be, shall furnish such Services to the Client Company at such times, for such periods and in such manner as the Client Company shall have so requested and otherwise in accordance with the provisions hereof.

(b) For purposes of this Agreement, "Services" may include, but shall not be limited to: (i) in the case of Services that may be provided by Operating Company hereunder, services in such areas as engineering and construction; operations and maintenance; installation services; equipment testing; generation technical support; environmental, health and safety; and procurement services; and (ii) in the case of Services that may be provided by Nonutility Companies hereunder, services in such areas as information technology services; monitoring, surveying, inspecting, constructing, locating and marking of overhead and underground utility facilities; meter reading; materials management; vegetation management; and marketing and customer relations.

(c) For the avoidance of doubt, affiliate transactions involving sales or other transfers of assets, goods, energy commodities (including electricity, natural gas, coal and other combustible fuels) or thermal energy products are outside the scope of this Agreement.

Section 1.2 Loaned Employees.

(a) If specifically requested in connection with the provision of Services, Service Provider shall loan one or more of its employees to such Client Company, provided that such loan shall not, in the sole discretion of Service Provider, interfere with or impair Service Provider's utility responsibilities or business operations, as the case may be. After the commencement thereof, any such loaned employees may be withdrawn by Service Provider from tasks duly assigned by Client Company, prior to completion thereof as contemplated in the associated Service Request, only with the consent of Client Company (which shall not be unreasonably withheld or delayed), except in the event of a demonstrable emergency requiring the use of any such employees in another capacity for Service Provider.

(b) While performing work on behalf of Client Company, any such loaned employees shall be under its supervision and control, and Client Company shall be responsible for their actions to the same extent as though such persons were its employees (it being understood that such persons shall nevertheless remain employees of Service Provider and nothing herein shall be construed as creating an employer-employee relationship between any Client Company and any loaned employees). Accordingly, for the duration of any such loan, Service Provider shall continue to provide its loaned employees with the same payroll, pension, savings, tax withholding, unemployment, bookkeeping and other personnel support services then being provided by Service Provider to its other employees.

ARTICLE 2. SERVICE REQUESTS

Section 2.1 Procedure. All Services (including any loans of employees) (i) shall be performed in accordance with Service Requests issued by or on behalf of Client Company and accepted by Service Provider and (ii) shall be assigned to applicable activities, processes, projects, responsibility centers or on other appropriate bases to enable specific work to be properly assigned. Service Requests shall be as specific as practicable in defining the Services requested. Client Company shall have the right from time to time to amend or rescind any Service Request, *provided* that (a) Service Provider consents to any amendment that results in a material change in the scope of Services to be provided, (b) the costs associated with an amended or rescinded Service Request shall include the costs incurred by Service Provider as a result of such amendment or rescission, and (c) no amendment or rescission of a Service Request shall release Client Company from any liability for costs already incurred or contracted for by Service Provider pursuant to the original Service Request, regardless of whether any labor or the furnishing of any property or other resources has been commenced or completed.

ARTICLE 3. COMPENSATION FOR SERVICES

Section 3.1 Cost of Services. Except to the extent otherwise required by Section 482 of the Internal Revenue Code or analogous state tax law, as compensation for any Services rendered to it pursuant to this Agreement, Client Company shall pay to Service Provider an amount consistent with the Commonwealth of Kentucky's affiliate transaction pricing requirements, KRS 278.2207. Accordingly (i) Services provided by the Operating Company to a Nonutility Company shall be priced at the greater of Cost or market, and (ii) Services provided by a Nonutility Company to the Operating Company shall be priced at the lesser of Cost or market. "Cost" means the sum of (i) direct costs, (ii) indirect costs and (iii) costs of capital. As soon as practicable after the close of each month, Service Provider shall render to each Client Company a statement reflecting the billing information necessary to identify the costs charged for that month. By the last day of each month, Client Company shall remit to Service Provider all charges billed to it. For avoidance of doubt, the Service Provider and each Client Company may satisfy the foregoing requirement by recording billings and payments required hereunder in their common accounting systems without rendering paper or electronic monthly statements or remitting cash payments.

ARTICLE 4. LIMITATION OF LIABILITY; INDEMNIFICATION

Section 4.1 Limitation of Liability/Services. In performing Services pursuant to Section 1.1 hereof, Service Provider will exercise due care to assure that the Services are performed in a workmanlike manner in accordance with the specifications set forth in the applicable Service Request and consistent with any applicable legal standards. The sole and exclusive responsibility of Service Provider for any deficiency therein shall be promptly to correct or repair such deficiency or to re-perform such Services, in either case at no additional cost to Client Company, so that the Services fully conform to the standards described in the first sentence of this Section 4.1. No Service Provider makes any other warranty with respect to the provision of Services, and each Client Company agrees to accept any Services without further warranty of any nature.

Section 4.2 Limitation of Liability/Loaned Employees. In furnishing Services under Section 1.2 hereof (i.e., involving loaned employees), neither the Service Provider, nor any officer, director, employee or agent thereof, shall have any responsibility whatever to any Client Company receiving such Services, and Client Company specifically releases Service Provider and such persons, on account of any claims, liabilities, injuries, damages or other consequences arising in connection with the provision of such Services under any theory of liability, whether in contract, tort (including negligence or strict liability) or otherwise, it being understood and agreed that any such loaned employees are made available without warranty as to their suitability or expertise.

Section 4.3 Disclaimer. WITH RESPECT TO ANY SERVICES PROVIDED UNDER THIS AGREEMENT, THE SERVICE PROVIDER THEREOF MAKES NO WARRANTY OR REPRESENTATION OTHER THAN AS SET FORTH IN SECTION 4.1, AND THE PARTIES

HERETO HEREBY AGREE THAT NO OTHER WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE), SHALL BE APPLICABLE TO THE PROVISION OF ANY SUCH SERVICES. THE PARTIES FURTHER AGREE THAT THE REMEDIES STATED HEREIN ARE EXCLUSIVE AND SHALL CONSTITUTE THE SOLE AND EXCLUSIVE REMEDY OF ANY PARTY HERETO FOR A FAILURE BY ANY OTHER PARTY HERETO TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

Section 4.4 Indemnification.

(a) Indemnification In Respect of Services Provided by Operating Company.

(i) In circumstances where Operating Company is a Service Provider: (x) subject to subparagraph (ii) of this Section 4.4(a), Service Provider shall release, defend, indemnify and hold harmless each Client Company, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any loss, liability, claim, damage, expense (including costs of investigation and defense and reasonable attorneys' fees), whether or not involving a third-party claim (collectively, "Damages"), incurred or sustained by or against Service Provider or any such Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services, and (y) each Nonutility Company that is a Client Company with respect to such Services shall release, defend, indemnify and hold harmless Service Provider, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any Damages incurred or sustained by or against Service Provider or any such Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services, to the extent such Damages are not covered by Service Provider's indemnification obligation as provided in the preceding clause (x) or exceed the liability limits provided in subparagraph (ii) of this Section 4.4(a).

(ii) Notwithstanding any other provision hereof, in circumstances where Operating Company is a Service Provider: (x) Service Provider's total liability hereunder with respect to any specific Services shall be limited to the amount actually paid to Service Provider for its performance of the specific Services for which the liability arises, and (y) under no circumstances shall Service Provider be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

(b) Indemnification In Respect of Services Provided by Any Nonutility Company.

(i) In circumstances where a Nonutility Company is a Service Provider (*i.e.*, where Operating Company is the Client Company): (x) subject to subparagraph (ii) of this Section 4.4(b), Service Provider shall release, defend, indemnify and hold harmless the Client Company, including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any Damages incurred or sustained by or against Client Company arising, directly or indirectly, from or in connection with Service Provider's negligence or willful misconduct in the performance of the Services.

(ii) Notwithstanding any other provision hereof, in circumstances where a Nonutility Company is a Service Provider (*i.e.*, where Operating Company is the Client Company), under no circumstances shall Service Provider be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

Section 4.5 Procedure for Indemnification. Within 15 business days after receipt by any Client Company of notice of any claim or the commencement of any action, suit, litigation or other proceeding against it (a "Proceeding") with respect to which it is eligible for indemnification hereunder, such Client Company shall notify Service Provider thereof in writing (it being understood that failure so to notify Service Provider shall not relieve the latter of its indemnification obligation, unless Service Provider establishes that defense thereof has been prejudiced by such failure). Thereafter, Service Provider shall be entitled to participate in such Proceeding and, at its election upon notice to such Client Company and at its expense, to assume the defense of such Proceeding. Without the prior written consent of such Client Company, Service Provider shall not enter into any settlement of any third-party claim that would lead to liability or create any financial or other obligation on the part of such Client Company for which it such Client Company is not entitled to indemnification hereunder. If such Client Company has given timely notice to Service Provider of the commencement of such Proceeding, but Service Provider has not, within 15 business days after receipt of such notice, given notice to Client Company of its election to assume the defense thereof, Service Provider shall be bound by any determination made in such Proceeding or any compromise or settlement made by Client Company. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice from the applicable Client Company to Service Provider.

ARTICLE 5. MISCELLANEOUS

Section 5.1 Amendments. Any amendments to this Agreement shall be in writing executed by each of the parties hereto. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with the Kentucky Public Service Commission for its review or otherwise, Operating Company shall comply in all respects with any such requirements.

Section 5.2 Effective Date; Term. This Agreement shall become effective on the Effective Date and shall continue in full force and effect as to each party until terminated by any party, as to itself only, upon not less than 30 days prior written notice to the other parties hereto. Any such termination of parties shall not be deemed an amendment hereto. This Agreement may be terminated and thereafter be of no further force and effect upon the mutual consent of all of the parties hereto.

Section 5.3 Additional Parties. After the Effective Date of this Agreement, additional Nonutility Companies may become parties to this Agreement by executing appropriate signature pages, whereupon any such additional signatory shall be deemed a "party" hereto all purposes hereof and shall thereupon become bound by the terms and conditions of this Agreement as if an original party hereto. The addition of any such further signatories, in the absence of any changes to the terms of this Agreement, shall not be deemed an amendment hereto.

Section 5.4 Entire Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto. Any oral or written statements, representations, promises, negotiations or agreements, whether prior hereto or concurrently herewith, are superseded by and merged into this Agreement.

Section 5.5 Severability. If any provision of this Agreement or any application thereof shall be determined to be invalid or unenforceable, the remainder of this Agreement and any other application thereof shall not be affected thereby.

Section 5.6 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any of the parties hereto without the prior written consent of each of the other parties. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 5.7 Governing Law. This Agreement shall be construed and enforced under and in accordance with the laws of the State of Kentucky, without regard to conflicts of laws principles.

Section 5.8 Captions, etc. The captions and headings used in this Agreement are for convenience of reference only and shall not affect the construction to be accorded any of the provisions hereof. As used in this Agreement, "hereof," "hereunder," "herein," "hereto," and words of like import refer to this Agreement as a whole and not to any particular section or other paragraph or subparagraph thereof.

Section 5.9 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed a duplicate original hereof, but all of which shall be deemed one and the same Agreement.

[REMAINDER OF PAGE INTENTIONALLY LEFT BLANK]

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on its behalf by an appropriate officer thereunto duly authorized.

DUKE ENERGY KENTUCKY, INC.

By: Nancy M Wright
Nancy M. Wright
Assistant Corporate Secretary

DUKE-AMERICAN TRANSMISSION COMPANY, LLC
(by Duke Energy Transmission Holding Company, LLC, its Parent)

By: Nancy M Wright
Nancy M. Wright
Assistant Corporate Secretary

CINCAP V, LLC
(by Duke Energy Commercial Enterprises, Inc., its Managing Member)

By: Nancy M Wright
Nancy M. Wright
Assistant Corporate Secretary

DEG BIOMASS, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

DEGS WIND SUPPLY, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

DEGS WIND SUPPLY II, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

DUKE ENERGY COMMERCIAL ENTERPRISES, INC.

By: Nancy M Wright

Nancy M. Wright
Assistant Corporate Secretary

DUKE ENERGY INDUSTRIAL SALES, LLC

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

DUKE ENERGY MARKETING AMERICA, LLC

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

DUKE VENTURES REAL ESTATE, LLC

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

HAPPY JACK WINDPOWER, LLC

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

KIT CARSON WINDPOWER, LLC

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

NORTH ALLEGHENY WIND, LLC

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

NOTRESS WINDPOWER, LLC
(by TE Notrees, LLC its General Partner)

By: Nancy M Wright

Nancy M. Wright
Assistant Secretary

OCOTILLO WINDPOWER, LLC
(by TE Ocotillo, LLC its General Partner)

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

SILVER SAGE WINDPOWER, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

THREE BUTTES WINDPOWER, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

TOP OF THE WORLD WIND ENERGY, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

LAUREL HILL WIND ENERGY, LLC

By: Nancy M Wright
Nancy M. Wright
Assistant Secretary

INTERCOMPANY ASSET TRANSFER AGREEMENT

This **Intercompany Asset Transfer Agreement** (this "Agreement") is made and entered into by and among Duke Energy Carolinas, LLC ("DEC"), a North Carolina limited liability company, Duke Energy Ohio, Inc. ("DEO"), an Ohio corporation, Duke Energy Indiana, LLC ("DEI"), an Indiana limited liability company, Duke Energy Progress, LLC ("DEP"), a North Carolina limited liability company, Duke Energy Florida, LLC ("DEF"), a Florida limited liability company, Duke Energy Kentucky, Inc. ("DEK"), a Kentucky corporation, and Piedmont Natural Gas Company, Inc., a North Carolina corporation(collectively the "Operating Companies" and, individually, an "Operating Company"). The Effective Date as stated herein is the date on which this Agreement is executed or, as may be required, submitted to the appropriate regulatory body for approval, whichever occurs last. This Agreement supersedes and replaces in its entirety all previous Intercompany Asset Transfer Agreements dated before the Effective Date of this Agreement.

WITNESSETH:

WHEREAS, Duke Energy Corporation ("Duke Energy") is a Delaware corporation;

WHEREAS, each Operating Company is a subsidiary of Duke Energy and a public utility company;

WHEREAS, in the ordinary course of their businesses, the Operating Companies maintain inventory and other assets for the operation and maintenance of their respective electric utility, and with respect to DEO DEK, and Piedmont, gas utility, businesses; and

WHEREAS, subject to the terms and conditions herein set forth, and taking into consideration the Operating Companies' utility responsibilities, each Operating Company is willing, upon request from time to time, to transfer Assets, as defined herein, to each other Operating Company, as each shall request from each other.

NOW, THEREFORE, in consideration of the premises and the mutual covenants herein contained, the parties agree as follows:

ARTICLE 1. TRANSFER OF ASSETS

Section 1.1 Transfer. Upon request from one party ("Recipient"), the other party ("Transferor") shall transfer to the Recipient those Assets requested by Recipient, provided that (i) Transferor believes, in its reasonable judgment, that such transfer will not jeopardize Transferor's ability to render electric utility service or natural gas utility service to its customers consistent with Good Utility Practice; (ii) the Cost of any shipment of transmission- or generation-related item(s) does not exceed $10,000,000; (iii) DEC and DEP shall not transfer any Asset hereunder in contravention of S.C. Code Ann. § 58-27-1300; (iii) DEK shall not transfer any Asset hereunder in contravention of KRS 278.218. and (iv) DEC and DEP may transfer or take receipt of any transmission transformers or other transmission-related equipment under this

Agreement to or from DEC, DEP or DEF. DEC and DEP shall not, however, transfer or take receipt of any transmission transformers or transmission-related equipment to or from DEO, DEI, and DEK, other than transmission-related equipment that may be used on/with transformers within a range of voltages or regardless of voltage. "Assets" means parts inventory, capital spares, equipment and other goods except for the following: coal; natural gas; fuel oil used for electric power generation; emission allowances; electric power; and environmental control reagents. "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in the United States during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

Section 1.2 Compensation. Except to the extent otherwise required by Section 482 of the Internal Revenue Code or analogous state tax law, Recipient shall compensate Transferor for any Assets transferred hereunder at Cost. "Cost" means (i) for items of inventory accounted for in the FERC Uniform System of Accounts account 154 ("Inventory Items"), the average unit price of such Inventory Items as recorded on the books of the Transferor, plus stores, freight, handling, and other applicable costs, and (ii) for assets other than Inventory Items, net book value.

Alternatively, to the extent that an Asset may be transferred under this Agreement, the Transferor and Recipient may agree that the Asset transferred to the Recipient be replaced in kind. In this event, Transferor and Recipient shall agree to the timing of such replacement, and other necessary terms and conditions, and such in-kind replacement shall be deemed a transferred Asset for all purposes hereunder.

Section 1.3 Payment. Each Operating Company shall reasonably cooperate with each other Operating Company to record billings and payments required hereunder in their common accounting systems.

Section 1.4 Delivery; Title and Risk of Loss. The parties shall cooperate in providing transportation equipment necessary to deliver the Assets to the Recipient. Assets will be delivered FOB transportation equipment at the Transferor's location where such Assets reside ("Shipping Point"). All costs of transportation, including the cost of transporting in-kind replacement Assets to Transferor, shall be borne by the Recipient. Title to and risk of loss of the transferred Assets shall pass from the Transferor to the Recipient at the Shipping Point.

ARTICLE 2. WARRANTIES

Section 2.1 Warranties. Each Operating Company, as Transferor, warrants that it will have good and marketable title to the Assets transferred hereunder. Further, each Operating Company, as Transferor, warrants that it shall obtain release of any liens or other encumbrances on the transferred Assets within a reasonable time. ALL ASSETS TRANSFERRED

HEREUNDER ARE BEING SOLD "AS IS, WHERE IS" AND WITHOUT ANY WARRANTY AS TO ITS CONDITION, INCLUDING WITHOUT ANY WARRANTY AS TO MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE.

Section 2.2 Disclaimer. WITH RESPECT TO ANY ASSETS TRANSFERRED HEREUNDER, EACH OPERATING COMPANY AS TRANSFEROR MAKES NO WARRANTY OR REPRESENTATION OTHER THAN AS SET FORTH IN SECTION 2.1, AND THE PARTIES HERETO HEREBY AGREE THAT NO OTHER WARRANTY, WHETHER STATUTORY, EXPRESS OR IMPLIED (INCLUDING BUT NOT LIMITED TO ALL WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND WARRANTIES ARISING FROM COURSE OF DEALING OR USAGE OF TRADE), SHALL BE APPLICABLE TO SUCH ASSETS. THE PARTIES FURTHER AGREE THAT THE REMEDIES STATED HEREIN ARE EXCLUSIVE AND SHALL CONSTITUTE THE SOLE AND EXCLUSIVE REMEDY OF ANY PARTY HERETO FOR A FAILURE BY ANY OTHER PARTY HERETO TO COMPLY WITH ITS WARRANTY OBLIGATIONS.

ARTICLE 3. INDEMNIFICATION

Section 3.1 Indemnification; Limitation of Liability.

(a) Subject to subparagraph (b) of this Section 3.1, each party (the "Indemnifying Party") shall release, defend, indemnify and hold harmless the other party (the "Indemnified Party"), including any officer, director, employee or agent thereof, from and against, and shall pay the full amount of, any loss, liability, claim, damage, expense (including costs of investigation and defense and reasonable attorneys' fees), whether or not involving a third-party claim, incurred or sustained by or against any such Indemnified Party arising, directly or indirectly, from or in connection with Indemnifying Party's negligence or willful misconduct in the performance of its obligations hereunder.

(b) Notwithstanding any other provision hereof, each party's total liability hereunder with respect to any Assets shall be limited to the amount actually paid to Transferor for such Assets for which the liability arises, and under no circumstances shall Transferor be liable for consequential, incidental, punitive, exemplary or indirect damages, lost profits or other business interruption damages, by statute, in tort or contract, under any indemnity provision or otherwise (it being the intent of the parties that the indemnification obligations in this Agreement shall cover only actual damages and accordingly, without limitation of the foregoing, shall be net of any insurance proceeds actually received in respect of any such damages).

Section 3.2 Procedure for Indemnification. Within 15 business days after receipt by an Indemnified Party of notice of any claim or the commencement of any action, suit, litigation or other proceeding against it (a "Proceeding") with respect to which it is eligible for indemnification hereunder, the Indemnified Party shall notify the Indemnifying Party thereof in writing (it being understood that failure so to notify the Indemnifying Party shall not relieve the latter of its indemnification obligation, unless the Indemnifying Party establishes that defense thereof has been prejudiced by such failure). Thereafter, the Indemnifying Party shall be entitled to participate in such Proceeding and, at its election upon notice to such Indemnified Party and at its expense, to assume the defense of such Proceeding. Without the prior written consent of such Indemnified Party, Indemnifying Party shall not enter into any settlement of any third-party claim that would lead to liability or create any financial or other obligation on the part of such Indemnified Party for which such Indemnified Party is not entitled to indemnification hereunder. If such Indemnified Party has given timely notice to Indemnifying Party of the commencement of such Proceeding, but Indemnifying Party has not, within 15 business days after receipt of such notice, given notice to Indemnified Party of its election to assume the defense thereof, Indemnifying Party shall be bound by any determination made in such Proceeding or any compromise or settlement made by Indemnified Party. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice from the applicable Indemnified Party to Indemnifying Party.

ARTICLE 4. MISCELLANEOUS

Section 4.1 Amendments. Any amendments to this Agreement shall be in writing executed by each of the parties hereto. To the extent that applicable state law or regulation or other binding obligation requires that any such amendment be filed with any affected state public utility commission for its review or otherwise, each Operating Company shall comply in all respects with any such requirements.

Section 4.2 Effective Date; Term. This Agreement shall become effective on the Effective Date and shall continue in full force and effect until terminated by either party upon not less than 30 days prior written notice to the other party. This Agreement may be terminated and thereafter be of no further force and effect upon the mutual consent of the parties hereto.

Section 4.3 Entire Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes any prior or contemporaneous contracts, agreements, understandings or arrangements, whether written or oral, with respect thereto. Any oral or written statements, representations, promises, negotiations or agreements, whether prior hereto or concurrently herewith, are superseded by and merged into this Agreement.

Section 4.4 Severability. If any provision of this Agreement or any application thereof shall be determined to be invalid or unenforceable, the remainder of this Agreement and any other application thereof shall not be affected thereby.

Section 4.5 Assignment. Neither this Agreement nor any of the rights, interests or obligations hereunder shall be assigned, in whole or in part, by operation of law or otherwise by any party hereto without the prior written consent of the other party. Any attempted or purported assignment in violation of the preceding sentence shall be null and void and of no effect whatsoever. Subject to the preceding two sentences, this Agreement shall be binding upon, inure to the benefit of, and be enforceable by, the parties and their respective successors and assigns.

Section 4.6 Governing Law. This Agreement shall be construed and enforced under and in accordance with the laws of the State of New York, without regard to conflicts of laws principles.

Section 4.7 Captions, etc. The captions and headings used in this Agreement are for convenience of reference only and shall not affect the construction to be accorded any of the provisions hereof. As used in this Agreement, "hereof," "hereunder," "herein," "hereto," and words of like import refer to this Agreement as a whole and not to any particular section or other paragraph or subparagraph thereof.

Section 4.8 Counterparts. This Agreement may be executed in one or more counterparts, each of which shall be deemed a duplicate original hereof, but all of which shall be deemed one and the same Agreement.

Section 4.9 DEC, DEP, and Piedmont Conditions. In addition to the terms and conditions set forth herein, with respect to DEC, DEP, and Piedmont, the provisions set out in Exhibit A are hereby incorporated herein by reference. In addition, except with respect to the pricing of Asset transfers as set forth herein, DEC's, DEP's and Piedmont's participation in this Agreement is explicitly subject to the Regulatory Conditions and Code of Conduct approved by the NCUC in its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct issued in Docket No. E-2, Sub 1095, Docket No. E-7, Sub 1100, and Docket No. G-9, Sub 682 ("Merger Order"), as such Regulatory Conditions and Code of Conduct may be amended from time to time. In accordance with Regulatory Condition 3.9 as approved in the Merger Order, nothing in this Agreement shall be construed or interpreted so as to commit DEC or DEP, or to involve DEC or DEP in, joint planning, coordination, or operation of generation, transmission, or distribution facilities with one or more affiliates nor shall it be interpreted as otherwise altering DEC's or DEP's obligations with respect to the Regulatory Conditions approved in the Merger Order. In the event of a conflict between the provisions of this Agreement and the Regulatory Conditions and Code, the Regulatory Conditions and Code shall govern, except as altered by the Commission by Order for this Agreement.

Section 4.10 DEI Conditions. DEI agrees and acknowledges that in accordance with its Affiliate Standards, Section II O (i) it will make Assets available to non-affiliated wholesale power marketers under the same terms, conditions and prices, and at the same time, as it makes Assets available to a DEO's wholesale power marketing function, and (ii) it will process all requests for Assets from DEO's wholesale power marketing function and non-affiliated wholesale power marketers on a non-discriminatory basis.

Section 4.11 Regulatory Approvals. This Agreement is expressly contingent on the receipt of all regulatory approvals or waivers deemed necessary by the parties.

IN WITNESS WHEREOF, each of the parties hereto has caused this Agreement to be executed on __________, 201__, on its behalf by an appropriate officer thereunto duly authorized.

Duke Energy Carolinas, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Indiana, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Ohio, Inc.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Kentucky, Inc.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Progress, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Duke Energy Florida, LLC

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

Piedmont Natural Gas Company, Inc.

By: ______________________
Nancy M. Wright
Assistant Corporate Secretary

EXHIBIT A

Duke Energy Carolinas, LLC, Duke Energy Progress, LLC and Piedmont Natural Gas Company, Inc. Conditions

In connection with the NCUC approval of the Merger in NCUC Docket No. E-2, Sub 1095, Docket No. E-7, Sub 1100, and Docket No. G-5, Sub 682, the NCUC adopted certain Regulatory Conditions and a revised Code of Conduct governing transactions between DEC, DEP, Piedmont, and their affiliates. Pursuant to the Regulatory Conditions, the following provisions are applicable to DEC, DEP, and Piedmont:

(a) DEC's, DEP's and Piedmont's participation in this Agreement is voluntary. DEC, DEP, or Piedmont is not obligated to take or provide services or make any purchases or sales pursuant to this Agreement, and DEC, DEP, or Piedmont may elect to discontinue its participation in this Agreement at its election after giving any required notice;

(b) DEC, DEP or Piedmont may not make or incur a charge under this Agreement except in accordance with North Carolina law and the rules, regulations and orders of the NCUC promulgated thereunder.

(c) DEC, DEP or Piedmont may not seek to reflect in rates any (A) costs incurred under this Agreement exceeding the amount allowed by the NCUC or (B) revenue level earned under this Agreement less than the amount imputed by the NCUC; and

(d) DEC, DEP or Piedmont shall not assert in any forum – whether judicial, administrative, federal, state, local or otherwise – either on its own initiative or in support of other entity's assertions, that the NCUC's authority to assign, allocate, make pro-forma adjustments to or disallow revenues and costs for retail ratemaking and regulatory accounting and reporting purposes is, in whole or in part, (A) preempted by Federal Law or (B) not within the Commission's power, authority, or jurisdiction; DEC, DEP, and Piedmont will bear the full risk of any preemptive effects of Federal Law with respect to this Agreement.