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 20

Duke Energy Kentucky, Inc.
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Forecasted Test Period Filing Requirements

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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
John L. Sullivan

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

JOHN L. SULLIVAN III

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 John L. Sullivan, III and my business address is 550 S. 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, Corporate Finance and Assistant Treasurer. I am also the Assistant Treasurer of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company). DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

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

I received a Bachelor of Arts degree from the University of North Carolina-Chapel Hill in 1995 and an MBA degree from Wake Forest University in 2000. From 2000 to 2009, I worked in Bank of America's Global Corporate & Investment Banking unit, providing corporate finance, capital markets and strategic advisory services to energy and power clients. In 2009, I joined Duke Energy as a General Manager in the Treasury group. In 2010, I moved to Duke Energy's Corporate Development group where I served as a Director responsible for managing various strategic transactions for the company's regulated and commercial businesses. In January 2016, I returned to Duke Energy's Treasury department and assumed my current role.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR, CORPORATE FINANCE AND ASSISTANT TREASURER.

A. I am responsible for financing the operations of Duke Energy and its subsidiary utilities. This includes the issuance of new debt and equity securities, and obtaining other sources of external funds. My responsibilities also include financial risk management for Duke Energy and its subsidiaries. Additionally, I maintain relationships with Duke Energy's commercial banks, the fixed income investor community and the credit rating agencies.

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. My testimony will address Duke Energy Kentucky's financial objectives, capital structure, and cost of capital. I will also discuss the current credit ratings and forecasted capital needs of Duke Energy Kentucky. Throughout my testimony, I will emphasize the importance of Duke Energy Kentucky's continued ability to meet its financial objectives and maintain strong credit quality. Additionally, I provided the following information to Duke Energy Kentucky witness Mr. Robert "Beau" Pratt for his use in preparing the forecasts: Duke Energy's dividend policy; Duke Energy Kentucky's debt rate assumptions; existing short-term and long-term debt balances; sales of accounts receivable; capital lease and equipment lease information; and information relating to the long-term debt financing. I sponsor Schedules J-1 through J-4 in response to Filing Requirement (FR) 16(8)(j). I also sponsor FR 12(2)(a), FR 12(2)(b), FR 12(2)(c), FR 12(2)(d), FR 12(2)(e), FR 12(2)(f), FR 12(2)(g), FR 12(2)(h), FR 16(7)(j), FR 16(7)(l) and FR 16(7)(r). Finally, I provided certain information to Duke Energy Kentucky witness Mr. Pratt for his use in preparation of FR 16(7)(h) and Schedule K in response to FR 16(8)(k), respectively.

II. DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES

Q. WHAT ARE DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES?

A. The Company at all times seeks to maintain its financial strength and flexibility, including its strong investment-grade credit ratings, thereby ensuring reliable access to capital on reasonable terms. Financial strength and access to capital are necessary for Duke Energy Kentucky to provide cost-effective, safe, and reliable service to its customers. Specific targets that support financial strength and flexibility include: 1) maintaining an equity component of the capital structure that is within the rating agencies' guidelines for Duke Energy Kentucky's credit rating; 2) maintaining strong credit quality; 3) ensuring timely recovery of prudently incurred costs; 4) maintaining sufficient cash flows to meet obligations; and 5) maintaining a sufficient return on equity to fairly compensate shareholders for their invested capital. The ability to attract capital (both debt and equity) on reasonable terms is vitally important to the Company and its customers, and each of these targets help the Company meet its overall financial objectives.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY'S CUSTOMERS WILL BENEFIT FROM DUKE ENERGY KENTUCKY ACHIEVING ITS CREDIT RATING OBJECTIVES.

A. There are many reasons why our customers will benefit from the credit rating objectives that we have established. The benefits of achieving and maintaining a strong investment-grade credit rating or higher are discussed in the pre-filed testimony of Duke Energy Kentucky witness Dr. Roger A. Morin. These benefits include lower overall financing costs and greater access to the capital markets, thus improving Duke Energy Kentucky's ability to maintain a safe, reliable, and low cost level of customer service.

Q. WHAT RATEMAKING TREATMENT IS BEING REQUESTED IN THIS PROCEEDING AND HOW WILL THE COMPANY'S FINANCIAL OBJECTIVES BE IMPACTED?

A. As explained by Duke Energy Kentucky witness James P. Henning, Duke Energy Kentucky is requesting an overall increase of $48,646,222, equating to an approximate 14.96 percent increase in overall rates. As part of this request, supported by the analysis and testimony of Duke Energy Kentucky witness Dr. Roger Morin, the Company is requesting an allowed ROE of 10.3 percent. The proposed capitalization in this request is comprised of 51.1 percent debt and 48.9 percent equity. Approval of the Company's request in this case will support its financial objectives by ensuring timely cash recovery of its prudently incurred costs.

III. CREDIT QUALITY & CREDIT RATINGS

Q. PLEASE EXPLAIN CREDIT QUALITY AND CREDIT RATINGS, AND HOW THEY ARE DETERMINED.

A. Credit quality (or creditworthiness) is a term used to describe a company's overall financial health and its willingness and ability to repay all financial obligations in full and on time. An assessment of Duke Energy Kentucky's creditworthiness is performed by Standard & Poor's (S&P) and Moody's Investors Service (Moody's), and results in Duke Energy Kentucky's credit ratings and outlook.

Many qualitative and quantitative factors go into this assessment. Qualitative aspects may include Duke Energy Kentucky's regulatory climate, its track record for delivering on its commitments, the strength of its management team, corporate governance, its operating performance, and its service territory. Quantitative measures are primarily based on operating cash flow and focus on Duke Energy Kentucky's ability to meet its fixed obligations (interest expense in particular) on the basis of internally generated cash and the level at which Duke Energy Kentucky maintains debt balances. The percentage of debt to total capital is another example of a quantitative measure. Creditors and credit rating agencies view both qualitative and quantitative factors in the aggregate when assessing the credit quality of a company.

Q. WHAT IS THE ROLE OF REGULATION IN THE DETERMINATION OF THE FINANCIAL STRENGTH OF A UTILITY COMPANY?

A. Investors, investment analysts, and the rating agencies regard regulation as one of the most important factors in assessing a utility company's financial strength.

These stakeholders want to be confident a utility company operates in a stable regulatory environment that will allow the company to recover prudently incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, and service requirements of its customers. Important considerations include the allowed rate of return, cash quality of earnings, timely recovery of capital investments, stability of earnings, and strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined and outcomes are equitably balanced between customers and investors.

Q. HOW ARE DUKE ENERGY KENTUCKY'S OUTSTANDING SECURITIES CURRENTLY RATED BY THE CREDIT RATING AGENCIES?

A. As of the date of this testimony, S&P and Moody's rated Duke Energy Kentucky's outstanding debt as follows:

Rating Agency	S&P	Moody's
Senior Unsecured Rating	A-	Baa1
Outlook	Stable	Stable

Q. WHEN WERE DUKE ENERGY KENTUCKY'S CURRENT CREDIT RATINGS ESTABLISHED?

A. Duke Energy Kentucky's current senior unsecured credit ratings were established by Moody's in November 1995 and by Standard & Poor's in April 2015. These ratings were affirmed by both rating agencies in January 2017.

Q. WHY IS IT IMPORTANT FOR DUKE ENERGY KENTUCKY TO HAVE STRONG INVESTMENT-GRADE CREDIT RATINGS?

A. To assure reliable and cost-effective service, and to fulfill its obligations to serve customers, the Company must continuously plan and execute major capital projects. This is the nature of regulated capital-intensive industries like electric and gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets continue to experience periods of volatility, most recently driven by the uncertainty surrounding fiscal, monetary and foreign policy under a new administration. Duke Energy Kentucky must be able to finance its needs throughout such periods and strong investment-grade credit ratings provide the Company with greater assurance of continued access to the capital markets on reasonable terms during periods of volatility.

Q. WHAT STRENGTHS AND WEAKNESSES HAVE THE CREDIT RATING AGENCIES IDENTIFIED WITH RESPECT TO DUKE ENERGY KENTUCKY?

A. As of the last affirmation of the Company's ratings, the rating agencies believe the Kentucky regulatory environment generally supports long-term credit quality with timely and sufficient recovery of prudently incurred costs and expenses. Generally speaking, the agencies have identified the following strengths and challenges when assessing the credit quality of Duke Energy Kentucky:

Credit Strengths:

- Financial metrics commensurate with its current ratings and stable outlook;
- Credit supportive regulatory environment in Kentucky; and
- Support from the Duke Energy corporate family.

Credit Challenges:

- Increasing capital expenditures, partly for environmental compliance;
  - The Company's proposal for an environmental tracker would be viewed favorably by the credit agencies and would help mitigate the regulatory lag Moody's refers to in its January 2016 credit opinion; and
- Relatively small size compared to other integrated utilities.

The rating agencies speak to the importance of a constructive regulatory framework and Duke Energy Kentucky's limited activity with base rate cases in recent years. Such comments highlight the importance of this proceeding's outcome in supporting credit quality and the Company's financial objectives.

IV. CAPITAL STRUCTURE AND COST OF CAPITAL

Q. WHAT IS DUKE ENERGY KENTUCKY'S PROPOSED CAPITAL STRUCTURE?

A. As mentioned earlier in my testimony, Duke Energy Kentucky's proposed capital structure is comprised of 51.1 percent debt and 48.9 percent equity, after making adjustments for purchase accounting and other items. The Company believes this proposed capital structure is the appropriate capital structure for Duke Energy Kentucky, as it introduces an appropriate amount of risk due to leverage and minimizes the weighted average cost of capital to customers. Approval of the proposed capital structure will help Duke Energy Kentucky maintain its credit quality to meet its ongoing business objectives. This level is also consistent with the Company's target credit ratings.

Q. WHAT IS DUKE ENERGY KENTUCKY'S COST OF EQUITY?

A. Duke Energy Kentucky witness Dr. Roger Morin testifies that the Company's cost of equity is in the upper half of a range between 9.0 percent and 10.7 percent, that is, 9.9 percent - 10.7 percent. The Company supports Dr. Morin's analysis and is requesting 10.3 percent as the Company's allowed ROE.

Q. WHAT ROLE DO EQUITY INVESTORS PLAY IN THE FINANCING OF DUKE ENERGY KENTUCKY, AND HOW WILL THE OUTCOME OF THIS CASE IMPACT THESE INVESTORS?

A. Equity investors provide the foundation of a company's capitalization by providing significant amounts of capital, for which an appropriate economic return is required. Duke Energy Kentucky compensates equity investors for the risk of their investment by targeting fair and adequate returns, a stable dividend policy, and earnings growth — these are necessary to preserve ongoing access to equity capital. Returns to equity investors are realized only after all operating expenses and fixed payment obligations (including debt principal and interest) of the Company have been paid. Because equity investors are the last in priority to a company's assets, their investment is at most risk should the company suffer any underperformance. For this reason, equity investors require a higher return on investment. Equity investors expect utilities like Duke Energy Kentucky to recover their prudently incurred costs and earn a fair and reasonable return for their investors. The Company's proposal in these proceedings supports this investor requirement.

Q. WHAT EFFECT DOES CAPITAL STRUCTURE AND RETURN ON EQUITY HAVE ON CREDIT QUALITY?

A. Capital structure and return on equity are important components of credit quality. Equity capital is subordinate to debt capital, thereby providing cushion and safer returns for debt investors. Accordingly, equity capital is a more expensive form of capital. The Company seeks to maintain a level of equity in the capital structure that ensures high credit quality, while minimizing its overall cost of capital. An adequate ROE will allow the Company to generate earnings and cash flows to properly compensate equity investors for their capital at risk while protecting debt investors with a higher degree of credit quality. High credit quality improves financial flexibility by providing more readily available access to the capital markets on reasonable terms, and ultimately lower debt financing costs.

Q. DO YOU BELIEVE THAT DUKE ENERGY KENTUCKY'S CAPITAL STRUCTURE HAS AN ADEQUATE EQUITY COMPONENT TO ENABLE DUKE ENERGY KENTUCKY TO ACHIEVE THE COMPANY'S FINANCIAL STRENGTH AND CREDIT QUALITY OBJECTIVES?

A. Yes. Duke Energy Kentucky's equity component, as supported in these proceedings, enables it to maintain current credit ratings and financial strength and flexibility. This level of equity enables the Company to operate through different business cycles while also providing a cushion to the Company's lenders and bondholders. The Company's current and future capital expenditures require the need for a strong equity component of the Company's capital structure in order to maintain access to capital funding at reasonable terms.

Q. PLEASE SUMMARIZE THE COMPANY'S AVERAGE COST OF SHORT-TERM AND LONG-TERM DEBT FOR THE BASE PERIOD AND THE FORECAST PERIOD AND THE KEY ASSUMPTIONS AND METHODOLOGY USED IN CALCULATING COST OF DEBT FOR SUCH PERIODS?

A. The table below presents the average cost of short-term and long-term debt for the Base and Forecast periods:

	Base Period (at November 2017)	**Forecast Period** (Avg of Mar 2018 thru Mar 2019)
Short-Term Debt (Schedule J-2)	2.062%	3.083%
Long-Term Debt (Schedule J-3)	4.253%	4.243%

For Schedule J-2, which calculates cost of short-term debt, the assumed Amount Outstanding for Sale of Accounts Receivables, for both the base and forecast period, was the average of the actual monthly balances for Duke Energy Kentucky's Sale of Account Receivables during the trailing twelve months as of May 2017. The assumed interest rate on this debt for the base and forecast period was derived using Bloomberg's Implied forward curve for one-month London Interbank Offered Rate (LIBOR) as of July 2017 plus a 75 basis point credit spread. The Amount Outstanding for the Notes Payable to Associated Companies in the forecasted short-term debt schedule is the thirteen-month average of Duke Energy Kentucky's monthly money pool borrowing balance from current company projections. The Interest rate on this debt was derived using Bloomberg's implied forward curve for one month LIBOR as of July 2017.

For Schedule J-3, which calculates the cost of long-term debt, the interest rate on $25 million of LT Commercial Paper for the base and forecast period was derived using Bloomberg's Implied forward curve for one month LIBOR as of July 2017 plus a 25 credit spread. A long-term debt issuance of $70 million is forecasted for October 2018 based on company projections. The interest rate on this future issuance was estimated using a blended average of Bloomberg's forward curves for the 10-year and 30-year US Treasury yield as of July 2017 plus a 145 basis point credit spread.

Q. DID DUKE ENERGY COMPANY TAKE ANY STEPS SINCE ITS LAST ELECTRIC BASE RATE CASE IN 2006 TO MANAGE ITS FINANCING COSTS, THUS MITIGATING THE RATE INCREASE PROPOSED IN THIS CASE?

A. Yes. Duke Energy Kentucky has effectively managed its financing costs since the last electric base rate case in 2006. In that rate case, the average cost of long-term debt for both the base and forecasted periods was expected to exceed 5.50%. In this rate case, the average cost of long-term debt in both periods is expected to be approximately 4.25%. In Duke Energy Kentucky's most recent debt offering, the Company priced $90 million of debt through the traditional private placement market. The transaction was well-received by the market and achieved efficient pricing across three series of notes at a weighted-average cost of approximately 3.90% and a weighted average life of 27 years.

V. DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS

Q. WHAT ARE DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS DURING THE 2017-2019 TIME PERIOD?

A. Duke Energy Kentucky faces substantial capital needs over the next several years to satisfy debt maturities, upgrade aging infrastructure, and to further invest in energy efficiency. The Company's capital requirement for the regulated business of Duke Energy Kentucky is projected to be approximately $605 million during the period – 2017-2019. This amount consists of approximately $505 million in projected capital expenditures and approximately $100 million in debt maturities.

Q. HOW WILL DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS BE FUNDED?

A. Duke Energy Kentucky's capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity contributions. It is important to remember that Duke Energy also has dividend obligations to its shareholders. Duke Energy's operating subsidiaries are expected to distribute approximately 70 percent of their earnings over the long-run in support of these obligations.

VI. SCHEDULES, FILING REQUIREMENTS AND INFORMATION SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES J-1.

A. These J schedules are embodied in FR 16(8)(j). Specifically, Schedule J-1, entitled "Cost of Capital Summary" sets forth the projected capital structure and capitalization ratios of Duke Energy Kentucky at November 30, 2017, and the average of the projected balances and rates for the thirteen-month period ending

March 31, 2019. The weighted cost of the various capital components is computed by multiplying the respective capitalization ratio by the computed annualized cost rate. The overall weighted cost of capital is reflected in the rate of return requested for the thirteen-month period ending March 31, 2019.

Q. PLEASE DESCRIBE SCHEDULES J-2 AND J-3.

A. Schedule J-2, entitled "Embedded Cost of Short-Term Debt," and Schedule J-3, entitled "Embedded Cost of Long-Term Debt," set forth the calculations of the cost of short-term debt and long-term debt, respectively, of Duke Energy Kentucky. The information on page 1 of these schedules was computed at the date of the base period, November 30, 2017. On page 2, the balances and interest rates are based on the average of the projected balances and rates for the thirteen-month period ending March 31, 2019.

Q. WHY IS SCHEDULE J-4 NOT INCLUDED?

A. Schedule J-4 is designed to provide the embedded cost of preferred stock for Duke Energy Kentucky. Since Duke Energy Kentucky has no preferred stock, this schedule has not been filed.

Q. DO YOU SPONSOR ANY OF THE INFORMATION CONTAINED IN ANY OTHER SCHEDULES?

A. Yes. I sponsor the percentage of construction expenditures financed internally, fixed coverage ratios and the rating agencies' ratings in Schedule K.

Q. PLEASE DESCRIBE FR 12(2)(a).

A. FR 12(2)(a) provides the amount and kinds of stock authorized.

Q. PLEASE DESCRIBE FR 12(2)(b)

A. FR 12(2)(b) provides the amount and kinds of stock issued and outstanding as of June 30, 2017.

Q. PLEASE DESCRIBE FR 12(2)(c).

A. FR 12(2)(c) is a requirement to provide certain terms and conditions for any preferred stock. Since Duke Energy Kentucky has no preferred stock, there is no information to provide.

Q. PLEASE DESCRIBE FR 12(2)(d).

A. FR 12(2)(d) provides a description of certain terms and conditions for any mortgages. Since Duke Energy Kentucky has no mortgages, there is no information to provide.

Q. PLEASE DESCRIBE FR 12(2)(e).

A. FR 12(2)(e) provides certain terms and conditions for any bonds authorized and issued.

Q. PLEASE DESCRIBE FR 12(2)(f).

A. FR 12(2)(f) provides certain terms and conditions for any notes issued. Duke Energy Kentucky had other notes outstanding beyond those summarized in 12(2)(e) and 12(2)(g).

Q. PLEASE DESCRIBE FR 12(2)(g).

A. FR 12(2)(g) provides certain terms and conditions for other indebtedness, including information on two outstanding series of Pollution Control Bonds, three capital leases and information on money pool borrowings.

Q. PLEASE DESCRIBE FR 12(2)(h).

A. FR 12(2)(h) provides certain information regarding dividend payments by Duke Energy Kentucky during the past five years.

Q. PLEASE DESCRIBE THE INFORMATION YOU PROVIDED IN SUPPORT OF FR 16(7)(h).

A. The information I sponsor on FR 16(7)(h) includes Duke Energy Kentucky's capital structure requirements. I provided this information to Mr. Pratt for his preparation of the Company's financial forecast.

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

A. FR 16(7)(j) is a requirement to provide copies of the prospectuses of the most recent stock or bond offerings.

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

A. FR 16(7)(l) is a requirement to provide copies of the consolidated annual report to shareholders and statistical supplements for the last five years.

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

A. FR 16(7)(r) is a requirement to provide copies of the quarterly reports to shareholders.

Q. PLEASE DESCRIBE THE INFORMATION YOU PROVIDED FOR SCHEDULE K IN RESPONSE TO FR 16(8)(K).

A. The information I sponsor includes Duke Energy Kentucky's senior unsecured credit ratings, various credit ratios and the percentage of construction expenditures financed internally. I also provided information relating to consolidated capital structure and common stock related data to Mr. Doss and Ms. Lee for their use in preparing Schedule K.

VII. CONCLUSION

Q. WERE SCHEDULES J-1 THROUGH J-4 IN RESPONSE TO FR 16(8)(j), FR 12(2)(a), FR 12(2)(b), FR 12(2)(c), FR 12(2)(d), FR 12(2)(e), FR 12(2)(f), FR 12(2)(g), FR 12(2)(h), FR 16(7)(j), FR 16(7)(l), FR 16(7)(r), AND THE INFORMATION YOU PREPARED SUPPORTING FR 16(7)(h) AND SCHEDULE K PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. IS THE INFORMATION YOU SPONSORED IN THOSE SUPPLEMENTAL FILING REQUIREMENTS AND SCHEDULES 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, John L. Sullivan, III, Director, Corporate Finance and Assistant Treasurer, 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.

John L. Sullivan, III

John L. Sullivan, III Affiant

Subscribed and sworn to before me by John L. Sullivan, III on this 17th day of August, 2017.

HEATHER PAIGE BLUM NOTARY PUBLIC MECKLENBURG COUNTY, N.C.

Heather Paige Blum

NOTARY PUBLIC

My Commission Expires: 1-9-2018

Direct Testimony of
John D. Swez

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

JOHN D. SWEZ

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Swez and my business address is 526 S. Church Street, Charlotte, North Carolina 28202.

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

A. I am employed as Director, Generation Dispatch and Operations in the Fuels and Systems Optimization Department, by Duke Energy Carolinas, LLC, a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company).

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

A. I received a Bachelor of Science degree in Mechanical Engineering from Purdue University in 1992. I received a Master of Business Administration degree from the University of Indianapolis in 1995. I joined PSI Energy, Inc., in 1992, and have held various engineering positions with the Company or its affiliates in the generation dispatch or power trading departments. In 2003, I assumed the position of Manager, Real-Time Operations. Though my title has changed on several occasions, I assumed my current role on January 1, 2006.

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

A. Yes, I have testified before the Kentucky Public Service Commission (Commission) on several occasions.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS DIRECTOR, GENERATION DISPATCH & OPERATIONS.

A. I am responsible for the Company's: (i) generation dispatch; (ii) unit commitment; (iii) 24-hour real-time operations; and (iv) short-term generating maintenance planning. I am also responsible for the submission of the Company's supply offers to the PJM Interconnection, L.L.C. (PJM) regional transmission organization (RTO) Day-Ahead and Real-Time electric power markets, as well as managing the Company's short-term supply position to ensure that the Company has adequate resources committed to serve its retail customers' electricity needs.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to describe the Company's participation in PJM and also describe the various PJM Billing Line Item (BLI) charges and credits that Duke Energy Kentucky receives as a PJM member. I describe the costs that are currently reflected in the Company's Fuel Adjustment Clause (FAC) or the Profit Sharing Mechanism (PSM). I discuss and support the Company's proposal for recovery of those BLI charges and credits in this proceeding, including the amounts included in the Company's test period in this proceeding. In doing so, I discuss the fuel-related charges and credits that should be included in the FAC going forward. Similarly, I discuss the Company's proposal for recovery of the PJM BLI charges and credits in the Company's Rider PSM and through the Company's proposed new reconciliation mechanism, the Federal Energy Regulatory Commission (FERC) Transmission Cost Reconciliation Rider (Rider FTR).

II. DUKE ENERGY KENTUCKY'S PARTICIPATION IN PJM

Q. PLEASE GENERALLY DESCRIBE PJM.

A. Duke Energy Kentucky has been a member of PJM since January 1, 2012. PJM is the nation's first fully functioning RTO and manages the power grid and wholesale electric market for all or parts of thirteen states and the District of Columbia. As discussed herein and in the Direct Testimony of Duke Energy Kentucky witness, Mr. John A. Verderame, this electric market consists of energy, capacity, ancillary services markets (ASM), and a financial transmission rights market. PJM's operation is governed by agreements approved by the Federal Energy Regulatory Commission (FERC), including the Operating Agreement, Open Access Transmission Tariff (OATT), and the Reliability Assurance Agreement (RAA). As a member of PJM, Duke Energy Kentucky is subject to these agreements, which among other things require Duke Energy Kentucky to offer all of its available generation to PJM and to purchase its customer energy load requirements from the PJM Day-Ahead or Real-Time Energy Markets. The Day-Ahead and Real-Time Energy Markets are collectively referred to as the PJM Energy Market for the remainder of my testimony.

Q. PLEASE EXPLAIN HOW THE COMPANY MEETS ITS ENERGY NEEDS THROUGH THE PJM ENERGY MARKET.

A. Consistent with its PJM membership, the Company meets all of its energy needs through the PJM Energy Market and does not currently purchase any energy outside of PJM. Through PJM's Day-Ahead Market, market participants can mitigate their exposure to real-time price risk by selling available generation and purchasing forecasted demand in the Day-Ahead Energy Market. Duke Energy Kentucky submits demand bids and supply offers as both a load serving entity (LSE) and a generator owner, respectively. Thus, the Company simultaneously functions as both a buyer and seller to serve its retail electric customers.

Q. PLEASE BRIEFLY DESCRIBE THE PJM ENERGY MARKET.

A. PJM administers its Energy Markets utilizing locational marginal pricing (LMP). LMP can be broadly defined as the value of one additional megawatt of energy at a specific point on the electric grid. In PJM, LMP is composed of three components: the system marginal energy price; the transmission marginal congestion price; and the marginal loss price. Both the Day-Ahead and Real-Time Energy Markets are based on supply offers and demand bids submitted to PJM by market participants or actual customer demand, including both generator owners (as sellers) and load serving entities (as buyers).

The Day-Ahead Energy Market provides a means for market participants to mitigate their exposure to price risk in the Real-Time Energy Market. The Day-Ahead Energy Market also provides meaningful information to PJM regarding expected real-time operating conditions for the next day, which enhances PJM's ability to ensure reliable operation of the transmission system and economically serve customer demand. The Real-Time Energy Market functions as a balancing market between generation and load in real-time. Through the PJM Energy Markets and the LMP price signals, PJM provides a market-based solution to value and thus manage energy production, transmission congestion, and marginal losses in the PJM region to meet demand in the most cost-effective way.

Q. PLEASE DESCRIBE PJM'S ASM AND HOW DUKE ENERGY KENTUCKY PARTICIPATES IN THOSE MARKETS.

A. PJM's ASM consists of the following services:

- Synchronized Reserves, which provide energy during an unexpected period of need within 10 minutes;
- Non-Synchronized Reserves, which also provide energy during an unexpected period of need and within 10 minutes, but which are typically off-line;
- Regulation and Frequency Responsive Reserves, which are utilized to continuously balance resources with demand and maintain interconnection frequency;
- Day-Ahead Scheduling Reserves, a 30-minute day-ahead reserve product;
- Black Start Service, which provides energy for restoration of the grid following a shutdown condition;
- Reactive Supply and Voltage Control, which is produced by capacitors and generators and absorbed by reactors and other inductive devices;
- Reactive Services, which is to maintain transmission voltages within acceptable limits; and
- Synchronous Condensing, which are utilized to adjust reactive power conditions on the electric grid.

PJM's ASM is co-optimized within the PJM Energy Markets in order to minimize overall production costs and ensure reliability across the PJM footprint.

In addition to the physical Energy Market and ASM, PJM offers financial products that can be utilized to hedge exposure to the Energy Markets. Virtual transactions can hedge risk in the Real-Time Energy Market, and financial transmission rights can hedge exposure to day-ahead congestion costs. Financial transmission rights auctions are conducted annually and monthly. Financial transmission rights are defined with source and sink points that entitle and obligate the holder to a stream of revenues or charges based on the hourly day-ahead congestion price differences across the defined path. Duke Energy Kentucky utilizes financial transmission rights to manage the congestion risk from its generation stations to its load zone. Virtual transactions clear in the Day-Ahead Energy Market as virtual generators and loads at specific points on the grid. Virtual transactions settle based on the difference between the day-ahead and real-time LMP at the specific node. Duke Energy Kentucky may utilize virtual transactions to hedge generator performance risk, primarily during start up or as a potential operational contingency.

Other non-PJM operated financial markets that are based on PJM market settlements exist. Duke Energy Kentucky participates in these financial markets to hedge Duke Energy Kentucky's customers' exposure to day-ahead and real-time energy prices when its generation stations are unavailable due to planned maintenance outages.

Q. PLEASE EXPLAIN HOW PJM DISPATCHES GENERATING RESOURCES TO MEET DEMAND.

A. PJM performs a security constrained economic commitment and least-cost security constrained economic dispatch process that simultaneously optimizes energy and reserves for all generation in its footprint in determining which assets to commit and dispatch. This process takes into account the various, unique challenges faced in reliably and economically supplying energy to all loads across its footprint, most significantly aligning the production of energy simultaneously with the volatility in demand within the capability of the transmission network. PJM must continually act to account for the fact that customer demand is dynamic in nature, fluctuating over the course of a day, week, and season, while analyzing factors such as costs and operating characteristics of generation from different types of units within its entire footprint and expected and unexpected conditions on the transmission network that affect which generation units can be used to serve load economically and reliably given the numerous constraints that must be considered. Because of these challenges, PJM's dispatch process "is designed to be an optimization process so that a reliable supply of electricity at the lowest cost possible under the conditions prevailing in each dispatch time interval can be delivered."[1]

[1] FERC Docket AD05-13-000, *Report on Security Constrained Economic Dispatch by the Joint Board of PJM/MISO Region*, Attachment 1, at pg. 5 (May 24, 2006).

Importantly, PJM's decisions as to which generating units should be dispatched are not made exclusively based on the individual unit's cost. Although the price of energy at a generating unit is certainly important, PJM's dispatch process must take into account a number of factors, including system-wide reliability, transmission grid congestion and losses, and numerous operational conditions and constraints. PJM has access to complete information regarding the operation of its Day-Ahead and Real-Time Energy Markets in making the determination to commit and dispatch a unit. Because of the efficient and informed nature of PJM's dispatch methodology, a utility's energy purchases in PJM's Day-Ahead and Real-Time Energy Markets are the most efficient and economic means available to satisfy customer load. Stated another way, energy acquired by all load serving entities from PJM are necessarily and by definition purchased on an economic dispatch basis.

Q. PLEASE BRIEFLY EXPLAIN HOW DUKE ENERGY KENTUCKY'S CURRENT GENERATION PORTFOLIO PARTICIPATES AND IS DISPATCHED IN THE DAY-AHEAD AND REAL-TIME ENERGY MARKETS.

A. Under the terms of PJM's RAA, as a fixed resource requirement (FRR) entity and generation owner in PJM, Duke Energy Kentucky is under a must-offer requirement to offer all of its generation committed to the FRR plan into the Day-Ahead Energy Market. The generating units are offered by Duke Energy Kentucky, as the market participant, with commitment status designations including: Must Run, Economic, Emergency, Fixed Gen, and Unavailable. Units offered with a Must Run status are committed and are generally dispatched near minimum load or the output of the generating unit is decreased ("dispatched down") during periods when the marginal cost of the unit is above the LMP solved by the dispatch model, or the generating unit is dispatched near full load or the output is increased ("dispatched up") during periods when the marginal cost of the unit is below the LMP solved by the dispatch model. A commitment status of "Economic" means that a generating unit is available to be committed by PJM in the Day-Ahead or Real-Time market. Economic units will generally be committed if their "all in" costs, including startup costs, are economic across a period. Emergency status indicates that a unit is available to be committed by PJM in the case of an emergency event. Fixed Gen units are committed but intend to remain fixed or otherwise not follow PJM real-time dispatch. Unavailable status means that a generating unit is not available to be committed.

In making the decision regarding an individual unit's offer status, the Company considers various factors such as unit availability, forecasted locational marginal prices, unit generation production cost, PJM impacts (Day-Ahead Operating Reserve credits, balancing operating reserve changes, *etc.*), and the capability, risk, and economic impact from cycling the generating unit off-line and/or on-line. Before making any generation unit offer, Company personnel engage in a daily planning process designed to minimize the total customer cost by maximizing each unit's economic value.

Each generating unit is offered hourly with a segmented incremental energy price pair quantity and ancillary service offer curve across the unit's operational range as well as a start-up cost, no-load cost, and operating parameters. The hourly offers are based on numerous factors, including but not limited to, the daily fuel cost, unit efficiency, emissions and variable operations and maintenance (O&M) costs, maximum and minimum loadings, and plant output availability and physical characteristics. Unit commitment status is determined based upon unit availability, marginal energy costs, expected impact of certain PJM charges and credits, and anticipated market clearing prices.

Day-ahead generation unit offers are submitted to PJM by 10:30 Eastern Prevailing Time the day prior to energy flow. Generally by 13:30 Eastern Prevailing Time that day, following execution of a security constrained unit commitment model, PJM posts energy and ancillary services awards for the following day. These awards are financially binding on both Duke Energy Kentucky and PJM.

In real-time, Duke Energy Kentucky makes hourly updates to the energy and ancillary service offers, primarily with respect to unit availability, but also taking into account the unit's operating parameters. The Duke Energy Kentucky generation dispatchers follow PJM generation dispatch signal instructions and relay necessary instructions to the generation stations.

It is possible that in real-time, despite receiving a day-ahead energy award, PJM dispatch signals will instruct Duke Energy Kentucky units to move to generation loadings other than their day-ahead award level. These instructions are based on the real-time energy and ancillary services needs of the overall system as manifested through LMP price signals at the generator bus. If the real-time LMP is below a unit's marginal cost of energy, PJM will likely reduce output, or possibly delay or cancel a unit startup. Conversely, if system conditions have changed from day-ahead results, PJM may direct a Duke Energy Kentucky unit to start up even without a day-ahead energy award. Duke Energy Kentucky has an obligation and financial incentive to follow PJM dispatch instructions.

Q. PLEASE DESCRIBE HOW DUKE ENERGY'S GENERATING STATIONS PERFORM IN PJM'S ENERGY MARKETS.

A. Duke Energy Kentucky offers its generation and bids its load into the PJM market. For the Duke Energy Kentucky generating capacity, the Company offered its resources in an FRR capacity plan consistent with the Commission's directive and approval of the Company becoming a PJM member in Case No. 2010-00203. The generating resources that are committed in the FRR plan have a must-offer obligation for their energy in the Day-Ahead Energy Market. Duke Energy Kentucky witness Mr. Verderame discusses the PJM Capacity markets in greater detail through his direct testimony.

Duke Energy Kentucky's Miami Fort Unit 6, a 163 Megawatt (net) coal-fired unit (Miami Fort 6), retired on June 1, 2015. At that time, Miami Fort 6 ceased dispatching energy in the PJM Energy Markets and had to be removed from the Company's FRR capacity plan. Duke Energy Kentucky's other coal unit, East Bend, continues to compete favorably in the PJM market, with typical dispatch of this unit at full load during on-peak periods and even during much of the off-peak periods as well.

The Company's six natural gas-fired combustion turbines at Woodsdale station, which operate as peaking units, continue to see limited dispatch within the PJM energy markets. However, these units can and do clear for other ASM products, even though the actual generating unit may remain off-line during this time.

PJM commits and dispatches these resources via their security constrained unit commitment and least-cost economic dispatch software by modeling the Duke Energy Kentucky generating resources with all other generating resources in the PJM wholesale energy market. If not committed day-ahead, the Woodsdale units may still be called upon in real-time. There are separate LMPs calculated for Day-Ahead versus Real-Time Markets that are paid to the generators or charged to the load.

Q. PLEASE DESCRIBE THE PERFORMANCE OF DUKE ENERGY KENTUCKY'S GENERATING RESOURCES IN THE ASM.

A. Each of PJM's ASM products is cleared separately with different prices for each product. In addition, PJM reimburses service providers such as Duke Energy Kentucky for black start and reactive services. Woodsdale is currently a black start unit in the Company's black start plan and, in addition, two of the units are reimbursed for certain costs to provide black start service to PJM. Duke Energy Kentucky continues to operate its generating resources to optimize revenues available in PJM for ancillary services, black start, and reactive service as well as energy and capacity markets in a reliable manner for the benefit of customers and shareholders.

III. PJM BILLING LINE ITEM CHARGES AND CREDITS

Q. HOW DOES DUKE ENERGY KENTUCKY GET BILLED COSTS AND RECEIVE REVENUES RELATED TO ITS PARTICIPATION IN PJM?

A. PJM has a standard and robust process for accounting for all costs and credits accrued in participation of its markets. All costs and credits accrued as a member of PJM are invoiced weekly with a monthly true-up and settled by PJM through BLIs. The monthly bill includes a detailed listing of the different BLIs, with BLIs that start with a 1000 designation as costs and BLIs that start with a 2000 designation as credits. If a 1000 charge type is positive, that represents a charge, whereas a 1000 charge type that is negative represents a credit to the Company. Conversely, if a 2000 charge type is positive, that represents a credit, whereas a 2000 charge type that is negative represents a cost to the Company. BLIs provide a transparent process to account for costs caused and benefits incurred as a member. These BLIs include costs for use of the PJM managed interstate transmission grid, including reliability projects, as well as participation in the wholesale Energy Markets, ASM, and Capacity Markets.

Q. ARE PJM BLI CHARGES AND CREDITS FERC-APPROVED RATES?

A. Yes. PJM's operation is governed by agreements approved by the FERC including the Operating Agreement, OATT, and the RAA. All PJM BLIs are the result of activity under these FERC approved agreements.

Q. ARE THE TYPES OF CHARGES AND CREDITS CONTAINED WITHIN THE PJM BLIS SIMILAR TO WHAT A UTILITY WOULD EXPERIENCE IF IT WERE NOT A MEMBER OF AN RTO?

A. Yes. While it is true that the PJM BLI charges and credits are a function of the Company's membership in PJM, the types of charges and credits contained in PJM BLIs are similar to expenses (and revenues) that would be experienced if the Company were not in an RTO. However, if Duke Energy Kentucky were not in an RTO, it would likely experience greater costs as a stand-alone utility. In such a scenario, Duke Energy Kentucky would either have to become its own balancing authority or contract with another entity to operate as such and would be subject to FERC-approved Open Access Transmission Tariffs (OATTs). In addition, partly due to its relatively small size, the Company could see changes to the operation of its generators, additional costs for agreements to maintain certain North American Energy Reliability Corporation (NERC) standards, other administrative fees, and additional bilateral energy and capacity purchases. These additional expenses would be necessary to attempt to maintain the same level of reliability. Finally, the Company would likely not experience the level of detail and transparency in terms of the BLIs it receives from PJM.

Q. PLEASE PROVIDE A COMPLETE AND CURRENT LIST OF PJM'S BLI CODES.

A. Attachment JDS-1 is a complete list of all PJM BLI charges and credits. Attachment JDS-2 is a copy of PJM's Customer Guide to PJM Billing that describes what each of PJM's BLIs is intended to charge or credit. JDS-3 is list of the PJM BLIs that the Company currently includes in its FAC and Rider PSM calculations.

Q. SINCE THE COMPANY's LAST BASE ELECTRIC RATE CASE, WHAT CHANGES HAVE OCCURRED REGARDING ITS PARTICIPATION IN A RTO?

A. Duke Energy Kentucky's last base electric rate case was in 2006, and used a forecasted test period of calendar year 2007. At that time, Duke Energy Kentucky was a member of the Midcontinent Independent System Operation f/k/a Midwest Independent System Operator (MISO), not PJM. The Company did not join PJM until 2012. The costs that are included in the Company's current base rates are the forecasted level of the categories of costs that existed in MISO when the Company filed its rate case in 2006. Duke Energy Kentucky's MISO membership lasted through 2011, and MISO continued to add its own BLIs after the Company's 2006 rate case. As a result, the Company continued (and in some cases continues today) to experience MISO costs and credits, that were never contemplated or reflected in rates. This includes the MISO transmission expansion plan costs (MTEP). The MTEP process was not approved or implemented by MISO until well after the Company's 2006 rate case, so such costs did not exist at the time of the Company's last rate case. There are currently $0 dollars reflected in base rates for any transmission expansion plan expenses.

Similarly, Duke Energy Kentucky exited MISO and became a member of PJM, with approval of this Commission, effective January 2012. Because the Company has not had a base rate case since it joined PJM, and because all PJM

BLIs don't perfectly parallel the BLIs that exist in MISO, there are PJM-related costs by way of its own BLIs that are not currently reflected in the Company's base rates. This would include, but is not limited to, the parallel expense to the MISO MTEP charge, the PJM Regional Transmission Expansion Plan (RTEP) expense.

IV. PJM BILLING LINE ITEM RECOVERY IN THE FUEL ADJUSTMENT CLAUSE (FAC)

Q. PLEASE LIST THE PJM BLI CODES THAT ARE CURRENTLY INCLUDED AS PART OF THE COMPANY'S MONTHLY FAC CALCULATION.

A. The PJM BLIs which are currently included as part of the Company's monthly FAC calculation are the portion of BLIs 1200, 1205, 1210, 1215, 1220, 1225, 2370, and 2375 to serve native load. The Day-Ahead and Real-Time Energy markets are settled through PJM BLIs 1200, 1205, 1210, 1215, 1220, and 1225. These represent both the costs to purchase customer load as well as the credits associated with running generating units. Both the energy, congestion, and loss component of LMP from both the Day-Ahead and Real-Time markets are separated as individual charge types in PJM. PJM BLIs 2370 and 2375 for Operating Reserve Credits received to service native load are also included in the FAC filing. Operating Reserve Credits, sometimes referred to as Make Whole Payments, are credits guaranteeing that a generator recovers its offered costs when following PJM commitment and dispatch instructions. A summary of these billing line items is as follows:

- **1200 - Day-Ahead Spot Market Energy**: BLI 1200 represents the net day-ahead energy component. Generally, revenue is being received when generation clears the day-ahead market and an expense is incurred for load purchased in the Day-Ahead market at the hourly PJM-wide day-ahead system energy price.
- **1205 – Balancing Spot Market Energy:** BLI 1205 represents the net real-time energy component deviation between the amount of generation cleared or demand bid purchased between the Day-Ahead and Real-Time markets and is charged at the hourly PJM-wide real-time system energy price. If there is no change to the quantity of demand bought or generation sold between the Day-Ahead and Real-Time Energy Markets, there is no adjustment in balancing spot market energy.
- **1210 – Day-Ahead Transmission Congestion**: BLI 1210 represents the change in energy costs due to re-dispatch in the Day-Ahead Market during hours when the PJM transmission system is constrained and assessed to participants based on the congestion price component of LMP.
- **1215 – Balancing Transmission Congestion**: BLI 1215 represents the change in energy costs due to re-dispatching in the balancing market during hours when PJM transmission system is constrained and assessed to participants based on the real-time congestion price component of LMP. If there is no change to the quantity of demand

bought or generation sold between the Day-Ahead and Real-Time Energy Markets, there is no balancing transmission congestion charges or credits.

- **1220 – Day-Ahead Transmission Losses**: BLI 1220 represents the change in energy costs due to transmission losses in the Day-Ahead Market represented in the PJM network model and assessed to participants based on the loss component of LMP.
- **1225 – Balancing Transmission Losses**: This BLI represents the change in energy costs due to transmission losses in the balancing market as represented in the PJM network model and is assessed to participants based on the real-time loss component of LMP. If there is no change to the quantity of demand bought or generation sold between the Day-Ahead and Real-Time energy markets, there is no adjustment in balancing transmission losses charges or credits.
- **2370 – Day-Ahead Operating Reserve Credit:** This BLI represents the credit paid to a generating unit in the Day-Ahead market when the initial amount paid to a generator is insufficient to cover its as offered costs.
- **2375 – Balancing Operating Reserve Credit:** This BLI represents the credit paid to a generating unit in the Real-Time market when the initial amount paid to a generator is insufficient to cover its as offered costs.

Q. WHY ARE THESE SPECIFIC BLIS APPROPRIATE FOR INCLUSION IN THE FAC?

A. BLI 1200, 1205, 1210, 1215, 1220 and 1225 represent the components of purchased power from PJM that were necessary to serve native load. These BLIs would exist in a different form absent the Company's involvement in PJM as either additional fuel expense from running additional, more expensive company assets or as purchased power but are materially the same thing as these BLIs. Thus, absent the Company's membership in PJM, if it were operating as stand-alone balancing authority, then in lieu of these BLIs, the Company would run additional generating units, incurring additional fuel expense, or make additional bilateral energy transactions to serve its load. Absent these power purchases from PJM, the Company would not be serving the energy needs of its native load customers.

BLIs 2370 and 2375 represent additional credits beyond payment from LMP to generators that are necessary to keep the generator whole to its offer. Thus, without these credits following the allocation of the fuel expense from an individual generator, the generator would get short changed and not receive the credit necessary to keep the unit whole to its offer.

Q. ARE THERE ANY ADDITIONAL PJM BILLING LINE ITEMS THAT THE COMPANY IS SEEKING TO BEGIN INCLUDING IN ITS FAC CALCULATION GOING FORWARD?

A. The BLIs proposed to be included in the FAC are either the entire amount or a partial amount of the following PJM BLIs: 1218, 1230, 1250, 1260, 1340, 1350, 1360, 1370, 1375, 1377, 1378, 1400, 1410, 1420, 1430, 1460, 1470, 1478, 1480, 1490, 1500, 1930, 2210, 2211, 2215, 2217, 2218, 2220, 2260, 2340, 2350, 2360, 2377, 2378, 2415, 2420, 2500, 2510, and 2930 as shown in JDS-4.

Q. WHAT PROCESS WAS USED TO DETERIME THAT THESE PJM BLIS SHOULD BE RECOVERED IN THE FAC?

A. At the beginning of 2016, Duke Energy Kentucky participated in a series of meetings with other Kentucky utilities[2] in PJM to discuss at a high level the various PJM Billing Line Items, what they fundamentally represented, how they were currently being recovered, and whether they should be recovered in the FAC. On January 29, 2016, Duke Energy Kentucky participated in an Informal Meeting at the Commissions offices to present the results. During this meeting, a handout was passed out and is included in this testimony as JDS-5 PRESENTATION Handout 1 – FAC BLI 01-29-16 – FINAL.xlsx. This handout has four sheets; BLIs – Uniform Recovery, BLIs – Non-Uniform Recovery, Additional BLIs – Eligible, and Additional BLIs – Not Eligible.

Q. PLEASE EXPLAIN WHY THE NEW BLIS IDENTIFIED FOR FAC RECOVERY ARE REASONABLE AND APPROPRIATE.

A. During the aforementioned process, every PJM BLI was examined and determined to either be related to use of fuel to run a generator, or not related to the use of fuel to run a generator. These BLIs can fall into a number of different types or categories, but in general are related to the load purchased and generation sold to

[2] The PJM member utilities participating in the discussion included Duke Energy Kentucky, Kentucky Power, and East Kentucky Power Cooperative.

PJM including the energy, congestion, and loss components, ancillary services, reconciliation amounts, and financial transmission rights associated BLI items. The BLIs that were related to the use of fuel are proposed to be included in the FAC and shown in JDS-5 on either the BLIs – Uniform Recovery, BLIs – Non-Uniform Recovery, or Additional BLIs – Eligible sheets.

Q. PLEASE EXPLAIN WHY UNDER THIS PROPOSAL THE ENTIRE AMOUNT OF THE BLIS ASSOCIATED WITH THE LOAD PURCHASED AND THE GENERATION RAN FOR NATIVE LOAD ARE INCLUDED IN THE FAC.

A. As previously mentioned, only a portion of certain BLIs that are associated with the amount of purchase power necessary to serve native load is currently being included in the FAC, and thus no BLIs associated with the energy, congestion, and losses associated with the load purchased and generation ran for native load are currently included in the FAC. The cost to serve native load is comprised of the fuel consumed in the generating unit run to serve native load, plus the cost to purchase energy for native load from PJM, offset with revenue received from PJM for running this generator. Since the amount of the load buy charge and generator revenue changes every hour in the Day-Ahead and Real-Time markets, the entire amount necessary to serve native load is proposed to be included in the FAC. Since these costs will include the congestion and loss component of load and generation, any BLI that is associated with congestion or losses such as financial transmission rights must be included as well since they tend to be revenues that offset these costs.

Q. PLEASE EXPLAIN WHY BLI CHARGES AND CREDITS RELATED TO TRANSMISSION LOSSES AND CONGESTION SHOULD BE RECOVERED IN THE FAC.

A. These BLIs represent the costs related to transmission losses and congestion, and since the majority of a generating units cost is fuel expense, these BLIs relate to the use of fuel. For example, if the Company were not in an RTO, the costs that make up these BLIs would be recovered through fuel expense since these charges and credits would be embedded inside of fuel. Through participation in PJM, specific itemized line items explicitly describe the charges and credits associated with transmission losses and congestion (BLIs 1210, 1215, 1218, 1220, 1225, 1410, 1420, 1500, 2210, 2211, 2215, 2217, 2218, 2220, 2415, 2420, 2500, and 2510). If the Company were not in PJM, the amount of fuel expense to serve native load included in its FAC would include the effect of transmission losses and congestion. For example, fuel used to generate electricity at a generation unit would include the amount consumed in losses that allow for delivery of energy to its customers. In addition, if it were not in an RTO, from time to time the Company could be forced to turn off or reduce its most economic unit on a given day or not be able to purchase energy from the lowest cost counterparty due to a transmission congestion limitation and would be included in the FAC through fuel consumption.

Q. PLEASE EXPLAIN WHY SOME, BUT NOT ALL BLIS RELATED TO THE ASM HAVE BEEN INCLUDED FOR FAC RECOVERY.

A. Not all ancillary services involve the consumption of fuel. Ancillary services such as Regulation and Frequency Response, Synchronized Reserve, Synchronous Condensing, and Reactive Services require units to be on-line and consuming fuel, and thus the native portion of these BLIs charges and credits are included for FAC recovery. Other ancillary services that don't require fuel consumption, such as Reactive Supply and Voltage Control from Generation and Other Sources Service, Non-Synchronized Reserve, Day-Ahead Scheduling Reserve, and Black Start Service would not be included in FAC recovery.

Q. PLEASE EXPLAIN WHY BLI 1930 AND 2930, GENERATION DEACTIVATION, ARE PROPOSED TO BE INCLUDED IN THE FAC.

A. These two BLIs are the charges or credits for a generating unit(s) that had requested retirement but is required by PJM to continue operation due to a grid reliably issue. Since these generators consume fuel when providing this service to the grid for the benefit of all PJM members, both the cost and credit are included in the FAC. There are currently two generators, Dominion's Yorktown 1 and 2, that have been required to remain operational by PJM with an allocation of these costs being allocated to the Company.

V. PJM BILLING LINE ITEM RECOVERY IN THE PROFIT SHARING MECHANISM (PSM)

Q. PLEASE LIST THE PJM BLI CODES THAT THE COMPANY PROPOSES TO INCLUDE IN THE COMPANY'S PSM CALCULATION

A. The Company is proposing that the same BLI categories that are included in the FAC calculation be included in the Rider PSM calculation, although with a different calculation methodology representing the amounts of these BLIs attributable to non-native sales. A portion of these BLIs are sometimes assigned to non-native sales, if the amount of generation is greater than customer demand in a given hour. Additionally, the Company is proposing other BLIs related to the Company's ownership and dedication of generating assets to Kentucky customers be included in the PSM. Specifically, the non-fuel ASM BLI costs and credits along with the BLIs associated with load response and emergency load response. As discussed by Duke Energy Kentucky witness Mr. William Don Wathen Jr., the Company is proposing these charges and credits be netted over the course of the calendar year along with the other items included in the PSM and the customer will receive 90% of the net margin.

The BLIs to be include in the PSM Off-System Sales calculation are: 1200, 1205, 1210, 2210, 2111, 1215, 2215, 2217, 1218, 2218, 1220, 2220, 1225, 1230, 1250, 1260, 2260, 1340, 2340, 1350, 2350, 1360, 2360, 1370, 2370, 1375, 2375, 1377, 2377, 1378, 2378, 1400, 1410, 2415, 1420, 2420, 1430, 1460, 1470, 1478, 1480, 1490, 1500, 2500, 2510, 1930, and 2930. The BLIs to be included for the non-fuel related ASM are: 1330, 2330, 1362, 2362, 1365, 2365, 1380, 2380, 1472, and 1475. The BLIs to be included for load response and emergency load response are: 1240, 2240, 1241, 2241, 1242, 1243, 1245, 2245, 1371, 2371, 1376, and 2376. These are shown in Attachment JDS-4.

Finally, to the extent that BLIs 1600 and 2600 pertain to capacity purchases and sales related to the Company's acquisition of the remaining 186 MW of East Bend as well as the 163 MW of capacity that was retired at Miami Fort 6, the net of these are included in the PSM. The capacity calculation of the PSM will also include additional capacity costs and credits as further discussed in the direct testimony of Duke Energy Kentucky witness John A. Verderame.

Q. PLEASE EXPLAIN WHY THESE BLIS IDENTIFIED FOR RIDER PSM RECOVERY ARE REASONABLE AND APPROPRIATE.

A. These BLIs are generally divided into two groups; the non-native portion of fuel-related BLIs and non-fuel related PJM BLIs. The non-native portion of the fuel related BLIs are reasonable and appropriate for the same reasons the native portion of these BLIs is includable in the FAC. These BLIs are directly related to a generators operation, consuming fuel, to allow for the non-native sale. For example, the non-native portion of BLI 1200 through 1225 would be included since these charges and credits make up the revenues received from PJM for operation of the generating unit that was used for the non-native sale. The non-native portion of fuel related ASM BLIs, such as Regulation and Frequency Response Service, Synchronized Reserve, Synchronous Condensing, and Reactive Services are included since these ancillary services require the use of an on-line generating unit that is consuming fuel. The other group, non-fuel related BLIs including ancillary services that the companies generators provide, such as Reactive Supply, Non-Synchronized Reserve, Day-Ahead Scheduling Reserve, and Black Start Service, don't require the use of fuel and represent typically both a charge and credit related to supply of this service. These non-fuel BLIs are appropriate to include in the PSM because it is a mechanism that the ratepayer will receive most of the value created from the generating stations and gives the Company a small incentive to maximize the value of this generation.

Q. CAN YOU EXPLAIN HOW THE CUSTOMER WILL RECEIVE VALUE AND THE COMPANY WILL BE INCENTIVIZED BY THE PSM?

A. As Mr. Wathen discusses in his testimony, the PSM is a mechanism to flow through to customers most of the profits the Company receives from owning and operating its generation. The customer will share in the Off-System Sales margin and the non-fuel net charges and credits associated with the generation assets and the capacity market.

VI. FERC TRANSMISSION COST RECONCILIATION RIDER

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO CREATE RIDER FTR.

A. As more fully explained by Duke Energy Kentucky witness Mr. Wathen, Rider FTR is intended to track the actual costs of FERC-jurisdictional transmission services that are incremental to (or decremented from) what is reflected in base rates. Rider FTR would track and reconcile transmission-related charges and credits such as network integration transmission service (NITS), both firm and non-firm point-to-point transmission service, transmission owner scheduling, system control and dispatch service, market administration fees, PJM's Regional Transmission Expansion Plan (RTEP) costs, and any other transmission related cost or credit that may be billed in the future by PJM that is used to supply retail load. The proposed Rider FTR allows Duke Energy Kentucky to recover its actual costs of providing transmission service to its native-load customers. As I previously stated, those types of charges are comparable to costs that could be assessed to Duke Energy Kentucky pursuant to other FERC-approved tariffs, or other agreements administered by a FERC-approved RTO or some other balancing authority if it were not in an RTO. Because Rider FTR would track both above and below (costs and credits) what is reflected in the Company's base rates, it will operate very similar to the Company's FAC.

Q. WHY IS IT APPROPRIATE TO IMPLEMENT RIDER FTR?

A. The Company has no control over these charges and credits which are assessed pursuant to tariffs that are approved by FERC and in accordance with processes administered by PJM, under the jurisdiction of FERC. Duke Energy Kentucky is a transmission dependent utility. Also, these costs are volatile insofar that they can change greatly from year to year. Absent the ability to track and reconcile the costs, the Company could be over or under recovering based upon levels contained in its base rates.

Simply put, the justification for tracking these expenses is the same for the tracking of fuel through the FAC. Rider FTR, if approved, will ensure that the Company recovers, and customers pay, no more or no less than the exact cost incurred to provide transmission service to its customers. Finally, tracking these costs independently and incrementally to base rates will provide the Commission with greater levels of transparency for these items on a more frequent basis than the current model that is limited to when the Company files a base rate case.

Q. PLEASE LIST THE PJM BLIS THAT WILL BE INCLUDED IN THE RECONCILIATION OF RIDER FTR.

A. The BLIs proposed to be included the reconciliation of Rider FTR are:

- Network Integration Transmission Service – billing line items 1100 and 2100;
- Transmission Enhancement (RTEP) – billing line items 1108 and 2108;
- Firm Point-to-Point Transmission Service – billing line items 1130 and 2130;
- Non-Firm Point-to-Point Transmission Service – billing line items 1140 and 2140;
- Market Administration Fees – billing line items 1301 through 1319 and 1440, 1441, 1442, 1444, 1445, 1446, 1447, 1448; and
- Transmission Owner Scheduling, System Control and Dispatch Service – billing line items 1320, 2320 and 1450.

Q. ARE THESE THE ONLY TRANSMISSION BLIs THE COMPANY IS REQUESTING RECOVERY FOR IN THE FTR?

A. No, the Company is requesting to include any other transmission related cost or credit that may be billed in the future by PJM to supply retail load. Attachment JDS-4 is a comprehensive list of all of the current transmission related PJM BLIs that PJM market participants could be charged or credited. However, many of these PJM charge types have never been billed to the Company.

Q. ARE THERE ANY TRANSMISSION BLIs THE COMPANY IS NOT REQUESTING RECOVERY FOR IN THE FTR?

A. Yes, the Company is not requesting to include BLI 1109 – MTEP Project Cost Recovery. Mr. Wathen discusses the reasons why the Company is not requesting to include MTEP in Rider FTR or any other recovery mechanism.

Q. DO YOU BELIEVE THE COMPANY'S PROPOSAL FOR RECOVERY OF PJM BLI CHARGES AND CREDITS IS REASONABLE?

A. Yes. All of PJM's BLIs (charges and credits) are pursuant to FERC-approved tariffs and are costs and credits that Duke Energy Kentucky experiences as a member of PJM and should be recoverable. I believe the Company's proposal appropriately groups together related PJM BLI (credits and charges) for the recovery of such costs appropriately based upon whether the costs and credits are fuel–related BLIs that are derived from serving Duke Energy Kentucky's customers (*i.e.* native load), off-system sales (non-native), or are other non-fuel related PJM costs and credits incurred to serve Duke Energy Kentucky's customers. Attachment JDS-4 includes a summary chart of all the BLIs depicting the category of costs in terms of rate recovery.

VII. CONCLUSION

Q. WERE ATTACHMENTS JDS-1, JDS-2, JDS-3, JDS-4, AND JDS-5 PREPARED BY YOU OR AT YOUR DIRECTION?

A. Yes.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

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

The undersigned, John D. Swez, Director, Generation Dispatch and Operations, 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.

John D. Swez

John D. Swez Affiant

Subscribed and sworn to before me by John D. Swez on this 27 day of July, 2017.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

Katie Jamieson

NOTARY PUBLIC

My Commission Expires: June 14, 2021

PJM Billing Statement Line Items			
ID #	CHARGES	ID #	CREDITS
1000	Amount Due for Interest on Past Due Charges		
1100	Network Integration Transmission Service	2100	Network Integration Transmission Service
1101	Network Integration Transmission Service (ATSI Low Voltage)	2101	Network Integration Transmission Service (ATSI Low Voltage)
1104	Network Integration Transmission Service Offset	2104	Network Integration Transmission Service Offset
		2106	Non-Zone Network Integration Transmission Service
1108	Transmission Enhancement	2108	Transmission Enhancement
1109	MTEP Project Cost Recovery	2109	MTEP Project Cost Recovery
1110	Direct Assignment Facilities	2110	Direct Assignment Facilities
1120	Other Supporting Facilities	2120	Other Supporting Facilities
1130	Firm Point-to-Point Transmission Service	2130	Firm Point-to-Point Transmission Service
		2132	Internal Firm Point-to-Point Transmission Service
1133	Firm Point-to-Point Transmission Service Resale	2133	Firm Point-to-Point Transmission Service Resale
1135	Neptune Voluntary Released Transmission Service (Firm)	2135	Neptune Voluntary Released Transmission Service (Firm)
1138	Linden Voluntary Released Transmission Service (Firm)	2138	Linden Voluntary Released Transmission Service (Firm)
1140	Non-Firm Point-to-Point Transmission Service	2140	Non-Firm Point-to-Point Transmission Service
		2142	Internal Non-Firm Point-to-Point Transmission Service
1143	Non-Firm Point-to-Point Transmission Service Resale	2143	Non-Firm Point-to-Point Transmission Service Resale
1145	Neptune Voluntary Released Transmission Service (Non-Firm)	2145	Neptune Voluntary Released Transmission Service (Non-Firm)
1146	Neptune Default Released Transmission Service (Non-Firm)	2146	Neptune Default Released Transmission Service (Non-Firm)
1147	Neptune Unscheduled Usage Billing Allocation		
1155	Linden Voluntary Released Transmission Service (Non-Firm)	2155	Linden Voluntary Released Transmission Service (Non-Firm)
1156	Linden Default Released Transmission Service (Non-Firm)	2156	Linden Default Released Transmission Service (Non-Firm)
1157	Linden Unscheduled Usage Billing Allocation		
1200	Day-ahead Spot Market Energy		
1205	Balancing Spot Market Energy		
1210	Day-ahead Transmission Congestion	2210	Transmission Congestion
		2211	Day-ahead Transmission Congestion
1215	Balancing Transmission Congestion	2215	Balancing Transmission Congestion
		2217	Planning Period Excess Congestion
1218	Planning Period Congestion Uplift	2218	Planning Period Congestion Uplift
1220	Day-ahead Transmission Losses	2220	Transmission Losses
1225	Balancing Transmission Losses		
1230	Inadvertent Interchange		
1240	Day-ahead Economic Load Response	2240	Day-ahead Economic Load Response
1241	Real-time Economic Load Response	2241	Real-time Economic Load Response
1242	Day-Ahead Load Response Charge Allocation		
1243	Real-Time Load Response Charge Allocation		
1245	Emergency Load Response	2245	Emergency Load Response
1250	Meter Error Correction		
1260	Emergency Energy	2260	Emergency Energy
1301	PJM Scheduling, System Control and Dispatch Service - Control Area Administration		
1302	PJM Scheduling, System Control and Dispatch Service - FTR Administration		
1303	PJM Scheduling, System Control and Dispatch Service - Market Support		
1304	PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration		
1305	PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.		
1306	PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center		
1307	PJM Scheduling, System Control and Dispatch Service - Market Support Offset		
1308	PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration		
1309	PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration		
1310	PJM Scheduling, System Control and Dispatch Service Refund - Market Support		
1311	PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration		
1312	Mgmt.		
1313	PJM Settlement, Inc.		
1314	Market Monitoring Unit (MMU) Funding		
1315	FERC Annual Charge Recovery		
1316	Organization of PJM States, Inc. (OPSI) Funding		
1317	North American Electric Reliability Corporation (NERC)		
1318	Reliability First Corporation (RFC)		
1319	Consumer Advocates of PJM States, Inc. (CAPS)		
1320	Transmission Owner Scheduling, System Control and Dispatch Service	2320	Transmission Owner Scheduling, System Control and Dispatch Service
1330	Reactive Supply and Voltage Control from Generation and Other Sources Service	2330	Reactive Supply and Voltage Control from Generation and Other Sources
1340	Regulation and Frequency Response Service	2340	Regulation and Frequency Response Service
1350	Energy Imbalance Service	2350	Energy Imbalance Service
1360	Synchronized Reserve	2360	Synchronized Reserve
1362	Non-Synchronized Reserve	2362	Non-Synchronized Reserve
1365	Day-ahead Scheduling Reserve	2365	Day-ahead Scheduling Reserve
1370	Day-ahead Operating Reserve	2370	Day-ahead Operating Reserve
1371	Day-ahead Operating Reserve for Load Response	2371	Day-ahead Operating Reserve for Load Response
1375	Balancing Operating Reserve	2375	Balancing Operating Reserve
1376	Balancing Operating Reserve for Load Response	2376	Balancing Operating Reserve for Load Response
1377	Synchronous Condensing	2377	Synchronous Condensing
1378	Reactive Services	2378	Reactive Services
1380	Black Start Service	2380	Black Start Service

PJM Billing Statement Line Items			
ID #	CHARGES	ID #	CREDITS
1390	Fuel Cost Policy Penalty	2390	Fuel Cost Policy Penalty
1400	Load Reconciliation for Spot Market Energy		
1410	Load Reconciliation for Transmission Congestion		
		2415	Balancing Transmission Congestion Load Reconciliation
1420	Load Reconciliation for Transmission Losses	2420	Load Reconciliation for Transmission Losses
1430	Load Reconciliation for Inadvertent Interchange		
1440	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service		
1441	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund		
1442	Load Reconciliation for Schedule 9-6 - Advanced Second Control Center		
1444	Load Reconciliation for Market Monitoring Unit (MMU) Funding		
1445	Load Reconciliation for FERC Annual Charge Recovery		
1446	Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding		
1447	Load Reconciliation for North American Electric Reliability Corporation (NERC)		
1448	Load Reconciliation for Reliability First Corporation (RFC)		
1450	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service		
1460	Load Reconciliation for Regulation and Frequency Response Service		
1470	Load Reconciliation for Synchronized Reserve		
1472	Load Reconciliation for Non-Synchronized Reserve		
1475	Load Reconciliation for Day-ahead Scheduling Reserve		
1478	Load Reconciliation for Balancing Operating Reserve		
1480	Load Reconciliation for Synchronous Condensing		
1490	Load Reconciliation for Reactive Services		
1500	Financial Transmission Rights Auction	2500	Financial Transmission Rights Auction
		2510	Auction Revenue Rights
1600	RPM Auction	2600	RPM Auction
1610	Locational Reliability		
		2620	Interruptible Load for Reliability
		2630	Capacity Transfer Rights
		2640	Incremental Capacity Transfer Rights
1650	Auction Specific MW Capacity Transaction	2650	Auction Specific MW Capacity Transaction
1660	Load Management Compliance Penalty	2660	Load Management Compliance Penalty
1661	Capacity Resource Deficiency	2661	Capacity Resource Deficiency
1662	Generation Resource Rating Test Failure	2662	Generation Resource Rating Test Failure
1663	Qualifying Transmission Upgrade Compliance Penalty	2663	Qualifying Transmission Upgrade Compliance Penalty
1664	Peak Season Maintenance Compliance Penalty	2664	Peak Season Maintenance Compliance Penalty
1665	Peak-Hour Period Availability	2665	Peak-Hour Period Availability
1666	Load Management Test Failure	2666	Load Management Test Failure
1667	Non-Performance	2667	Bonus Performance
1670	FRR LSE Reliability	2670	FRR LSE Reliability
1680	FRR LSE Demand Resource and ILR Compliance Penalty	2680	FRR LSE Demand Resource and ILR Compliance Penalty
1681	FRR LSE Capacity Resource Deficiency	2681	FRR LSE Capacity Resource Deficiency
1682	FRR LSE Generation Resource Rating Test Failure	2682	FRR LSE Generation Resource Rating Test Failure
1683	FRR LSE Qualifying Transmission Upgrade Compliance Penalty	2683	FRR LSE Qualifying Transmission Upgrade Compliance Penalty
1684	FRR LSE Peak Season Maintenance Compliance Penalty	2684	FRR LSE Peak Season Maintenance Compliance Penalty
1685	FRR LSE Peak-Hour Period Availability	2685	FRR LSE Peak-Hour Period Availability
1686	FRR LSE Load Management Test Failure	2686	FRR LSE Load Management Test Failure
1687	FRR LSE Schedule 9-5	2687	FRR LSE Schedule 9-5
1688	FRR LSE Schedule 9-6	2688	FRR LSE Schedule 9-6
1710	PJM/MISO Seams Elimination Cost Assignment	2710	PJM/MISO Seams Elimination Cost Assignment
1712	Intra-PJM Seams Elimination Cost Assignment	2712	Intra-PJM Seams Elimination Cost Assignment
1720	RTO Start-up Cost Recovery	2720	RTO Start-up Cost Recovery
1730	Expansion Cost Recovery	2730	Expansion Cost Recovery
1900	Unscheduled Transmission Service		
1910	Ramapo Phase Angle Regulators	2910	Ramapo Phase Angle Regulators
1911	Michigan - Ontario Interface Phase Angle Regulators		
		2912	CT Lost Opportunity Cost Allocation
1920	Station Power		
1930	Generation Deactivation	2930	Generation Deactivation
1932	Generation Deactivation Refund	2932	Generation Deactivation Refund
1950	Virginia Retail Administrative Fee	2950	Virginia Retail Administrative Fee
1952	Deferred Tax Adjustment	2952	Deferred Tax Adjustment
1955	Deferral Recovery	2955	Deferral Recovery
1980	Miscellaneous Bilateral	2980	Miscellaneous Bilateral
1995	PJM Annual Membership Fee		
		2996	Annual PJM Cell Tower
		2997	Annual PJM Building Rent
1999	PJM Customer Payment Default		

CUSTOMER GUIDE TO PJM BILLING

- Billing Line Items include PJM Open Access Transmission Tariff (OATT) references, PJM Operating Agreement (OpAgr) references, and PJM Manual references.
- Reports are available for viewing, printing, and downloading from PJM's Market Settlement Reporting System (MSRS).

Billing Line Item	Description	Reports
Network Integration Transmission Service (OATT Section 34, Attachments H-1 through H-17, Attachment H-A, and TOA Section 7.8 Manual 27, Section 5)	Network customers pay daily demand charges to PJM transmission owners using the applicable zonal or non-zone Network Integration Transmission Service rates. All network customers in the AP zone receive rebates to hold them harmless from the network rate conversion upon PJM integration. For transmission owners (except those in ATSI, PPL, ComEd, Dayton, Duke, and Duquesne zones), the charges for their own transmission facilities are not actually paid (i.e., exempted with an equal amount credits) and are shown only to identify their cost responsibility as ordered by FERC. ***Charges:*** Daily demand charges calculated as network customers' daily network service peak load contribution times 1/365th of the applicable zonal rate(s) for the zone(s) in which the network load is located. Monthly negative offset charges are rebated to AP zone network customers based on the applicable rates in PJM tariff Attachment H-11, section 4. Non-zone network service peak load contributions are coincident with the PJM Region peak. ***Credits:*** PJM zonal network transmission service revenues allocated to the applicable zone's transmission owners on a transmission revenue requirement basis. PJM non-zone network revenues allocated to transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	*NITS Charge Summary* *NITS Credit Summary* *NITS Offset Charge Summary* *Non-Zone NITS Credit Summary*
Firm Point-to-Point Transmission Service (OATT Section 13.7, Schedule 7, and TOA Section 7.8 Manual 27, Section 6)	Firm point-to-point transmission customers pay demand charges for reserved capacity at the applicable tariff rates based on the term of the reservations. There is no charge for reserved capacity with a MISO point of delivery. ***Charges:*** Monthly demand charges for daily, weekly, monthly, and yearly delivery calculated based on the transmission customer's reserved capacity times the applicable tariff rate. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the weekly delivery rate times the highest amount of reserved capacity in any day during such week. ***Credits:*** Total firm transmission service revenues allocated to PJM transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	*Firm PTP Charges* *Firm PTP Credit Summary*
Non-Firm Point-to-Point Transmission Service (OATT Sections 14.5 & 27A, Schedule 8 Manual 27, Section 6)	Non-firm point-to-point transmission customers pay demand charges for reserved capacity at the discounted rate. There is no charge for reserved capacity with a MISO point of delivery. ***Charges:*** Monthly demand charges for hourly, daily, weekly, and monthly delivery calculated based on the transmission customer's reserved capacity (in MWh) times the discounted rate of $0.67/MWh. Rebates are provided for transaction MWh curtailed by PJM and for transmission congestion charges. ***Credits:*** Total non-firm transmission service revenues allocated to PJM network and firm point-to-point transmission customers in proportion to their monthly demand charges.	*Non-Firm PTP Charges* *Non-Firm PTP Credit Summary*
Transmission Enhancement (OATT Schedule 12)	All network customers and merchant transmission owners pay transmission owners for required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates. ***Charges:*** All network customers serving load in a responsible zone pay for that zone's applicable projects' revenue requirements in proportion to their network service peak load share in that zone, and responsible merchant transmission owners also pay their share of applicable revenue requirements. Note that several EDCs bear these charges for the default suppliers in their territory. ***Credits:*** Total revenues allocated to the applicable transmission enhancement project owners, or the applicable transmission zone network customers for zonal TOs that include these project costs in their network rates.	*Transmission Enhancement Charge Summary* *Transmission Enhancement Credit Summary*

Billing Line Item	Description	Reports
Spot Market Energy (OpAgr Schedules 1-3.2.1 & 3.3.1 and OATT Schedule 4 Manual 28, Section 3)	Day-ahead energy market net hourly PJM Interchange MWh are calculated for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Real-time energy market net hourly PJM Interchange MWh are calculated for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. ***Day-ahead Charges:*** Net day-ahead PJM Interchange is charged hourly at the PJM-wide day-ahead system energy price. Charges are positive for net buyers and negative for net sellers of day-ahead spot market energy. ***Balancing Charges:*** Net real-time deviations from day-ahead PJM Interchange is charged hourly at the PJM-wide real-time system energy price. Charges may be positive or negative depending on the direction of the real-time deviation from day-ahead interchange. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	***DA Daily Energy Transactions*** ***RT Daily Energy Transactions*** for customer review and verification ***Spot Market Energy Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary***
Transmission Congestion (OpAgr Schedules 1-3.2.4, 3.4.1, & 5.1-5.2 Manual 28, Section 8)	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders. ***Day-ahead Charges:*** A day-ahead Net Congestion Bill is calculated hourly as the sum of day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead congestion prices) minus the sum of day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead congestion prices). Hourly day-ahead implicit congestion charges equal the day-ahead Net Congestion Bill. Hourly explicit congestion charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source congestion prices and are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Balancing Charges:*** A balancing Net Congestion Bill is calculated hourly as the sum of balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time congestion prices) minus the sum of balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time congestion prices). Hourly balancing implicit congestion charges equal the balancing Net Congestion Bill. Hourly explicit congestion charges for balancing energy transactions equal any real-time deviations from the transaction MWh cleared day-ahead times the difference between real-time sink and source congestion prices and assessed to the buyer (or point-to-point transmission customer, if applicable). ***Credits:*** Total congestion revenues allocated as hourly credits based on FTR target allocations (FTR MW times the difference between day-ahead FTR sink and source congestion prices). Excess hourly congestion credits (including NYISO Unscheduled Transmission Service revenues, net MISO and NYISO congestion adjustment, inadvertent interchange congestion contribution, and ARR and FTR Auction net revenues remaining after initial distribution to any ARR deficiencies) are used to proportionately eliminate target deficiencies in other hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period with any excess at the end of the planning period allocated proportionately to FTR holders with net positive FTR target allocations for that planning period. Any deficiencies remaining at the end of a planning period are eliminated by reallocating all planning period FTR congestion revenues among FTR holders to yield a uniform ratio of deficiency. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	***Transmission Congestion Charge Summary*** ***Explicit Congestion Charges*** ***Implicit Congestion and Loss Charge Details*** ***FTR Target Credits*** ***Hourly Transmission Congestion Credits*** ***Congestion and Loss Load Recon Charges*** ***Congestion Uplift Charge Summary*** ***Network ARR Target Credit Summary*** ***Cross-Monthly Congestion Credit Summary***

Planning Period Congestion Uplift (OpAgr Schedules 5.2.5 & 5.2.6 Manual 28, Section 8)	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. The "Planning Period Congestion Uplift credit" is a "make-whole" congestion credit to FTR holders to satisfy any previously unfulfilled FTR Target Credits that remain at the end of the planning year. A summary of FTR Targets and all applicable Congestion Credits broken down by month can be viewed in the "Cross-Monthly Congestion Credit Summary" report in MSRS. Select the "All Billed" option for the period from 6/1/12 through 5/31/13 to see the complete set of details. The "Planning Period Congestion Uplift charge" is the participant's share of the allocated costs of providing the Uplift credits. Charges are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year. Details of this charge allocation can be viewed in the "Congestion Uplift Charge Summary" report in MSRS. The calculation for the Uplift charge is: (positive FTR Target credit / Total PJM Positive FTR Target Credit) * PJM Total FTR and ARR Uplift Credit. The uplift process is also outlined in Manual 28, sections 8.1 and 8.4.4	***Congestion Uplift Charge Summary*** ***Cross-Monthly Congestion Credit Summary***
Planning Period Excess Congestion (OpAgr Schedule 5.2.6 Manual 28, Section 8.4.4)	For planning years in which the sum of total PJM congestion revenues collected during the planning year was greater than the sum of FTR holders' total net FTR Targets, Planning Period Excess Congestion credits are awarded to the FTR holders at the end of the planning year (May) to distribute those remaining excess congestion revenues. Planning Period Excess Congestion credits can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. Planning Period Excess Congestion credits are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year.	***Cross-Monthly Congestion Credit Summary***

Billing Line Item	Description	Reports
Transmission Losses (OpAgr Schedules 1-3.2.5, 3.4.2, & 5.4-5.5 Manual 28, Section 9)	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). ***Day-ahead Charges:*** An hourly day-ahead Net Loss Bill is calculated as day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead loss prices) minus day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead loss prices). Hourly day-ahead implicit loss charges equal the day-ahead Net Loss Bill. Hourly explicit loss charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable). ***Balancing Charges:*** An hourly balancing Net Loss Bill is calculated as balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time loss prices) minus balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time loss prices). Hourly balancing implicit loss charges equal the balancing Net Loss Bill. Hourly explicit loss charges for balancing energy transactions equal any real-time deviations from day-ahead transaction MWh times the difference between real-time sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable). ***Credits:*** Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving 31% of their allocation). ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag. ***Reconciliation Credits:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving 31% of their allocation) on a two-month billing lag.	***Transmission Loss Charge Summary*** ***Explicit Loss Charges*** ***Implicit Congestion and Loss Charge Details*** ***Transmission Loss Credit Summary*** ***Congestion and Loss Load Recon Charges*** ***Transmission Loss Load Recon Credit Summary***
Inadvertent Interchange (OpAgr Schedule 1-3.7 Manual 28, Section 18)	***Charges:*** PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	***Inadvertent Interchange Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary***
Load Response (OpAgr, just prior to Schedule 2 Manual 28, Section 11)	***Credits:*** Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWh times LMP . ***Charges:*** For day-ahead and real-time economic load response, the charges are allocated to all real-time load where load is served in a zone that has benefitted from load reductions plus real-time exports. For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	***Load Response Summary*** ***Econ Load Response Zonal Charge Allocations*** ***Emergency Load Response Allocation Summary*** ***Emergency Load Response Allocation Credits***
Meter Error Correction (OpAgr Schedule 1-3.6 Manual 28, Section 12)	***Charges:*** Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	***Meter Correction Charge Summary*** ***Meter Correction Allocation Charge Summary***
Emergency Energy (OpAgr Schedules 1-3.2.6, 3.3.4, 3.5.1, & 4.3 Manual 28, Section 10)	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. ***Charges:*** Hourly net costs of emergency energy purchased by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position, except for purchases for external control areas' MinGen Emergencies where costs are allocated to deviations that create a longer position. ***Credits:*** Hourly net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	***Emergency Energy Charge and Credit Allocation Summary*** ***Emergency Energy Transactions***

Billing Line Item	Description	Reports
PJM Scheduling, System Control & Dispatch Service (OATT Schedules 1 and 9-1 through 9-6 Manual 27, Section 2)	***Charges:*** PJM's monthly operating expenses for the following service categories are allocated to PJM members on an unbundled basis. Charge refunds are provided in the year following any year in which there is an over collection of PJM's monthly operating expenses. Control Area Administration – 2017 rate of $0.2100/MWh (with $0.0 refund rate for 2Q2017) charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use (in MWh) includes network customers' real-time load and point-to-point customers' real-time energy use. Financial Transmission Rights Administration – 2017 rate of $0.0028/FTR MWh (with $0.0/FTR MWh refund for 2Q2017) charged to FTR holders based on FTR MW and hours each FTR is in effect (regardless of congested hours and dollar value of FTR). 2017 rate of $0.0019/bid-hour (with $0.0 refund rate for 2Q2017) charged to FTR Auction participants based on the number of hours associated with each FTR obligation bid submitted in an FTR Auction (this rate is multiplied by 5 for FTR options). Market Support – 2017 rate of $0.0463/MWh (with $0.0 refund rate for 2Q2017) charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2017 rate of $0.0693 (with $0.0 refund rate for 2Q2017) is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Regulation and Frequency Response Administration – 2017 rate of $0.2819/Regulation MWh (with $0.0 refund rate for 2Q2017) charged to customers based on regulation obligation and regulation provided. Capacity Resource and Obligation Management – 2017 rate of $0.1073/MW-day (with $0.0 refund rate for 2Q2017) charged to LSEs based on their daily unforced capacity obligations and to capacity resource owners based on their daily unforced capacity (including FRRs). Costs of Advanced Second Control Center (AC^2) – This rate has been terminated. Market Support Offset –2Q2017 rate of $0.0035/MWh refunded to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids to reflect the reimbursement made to offset the PJM Settlement, Inc. charges. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the Control Area Administration Service Rate plus the Market Support Service Rate for transmission customers on a two-month billing lag. Charge refund amounts are also reconciled using the applicable refund rate billing determinants.	***Schedule 9 and 10 Charge Details*** ***Advanced Second Control Center Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
PJM Settlement, Inc. (OATT Schedule 9-PJMSettlement Manual 27, Section 2.2)	***Charges:*** 2Q2017 rate of $0.0035/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. This charge funds the administration of PJM Settlement, Inc. who acts as the contractual counterparty to PJM market transactions and performs the billing collection and credit management services for PJM members.	***Schedule 9 and 10 Charge Details***
MMU Funding (OATT Schedule 9-MMU Manual 27, Section 2)	***Charges:*** 2017 rate of $0.0059/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2017 rate of $0.0053 is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the MMU rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
FERC Annual Recovery (OATT Schedule 9-FERC Manual 27, Section 2)	***Charges:*** 2017 rate of $0.0759/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the FERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Organization of PJM States, Inc. (OPSI) Funding (OATT Schedule 9-OPSI Manual 27, Section 2)	***Charges:*** 2017 rate of $0.0007/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the OPSI rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***

Consumer Advocates of PJM States, Inc. (CAPS) Funding (OATT Schedule 9-CAPS Manual 27, Section 2)	***Charges:*** PJM will charge each customer using Network Integration and Point-to-Point Transmission Service each month a charge equal to the CAPS Funding Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region during such month. It is currently anticipated that CAPS Funding will not be collected until 2018. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the CAPS rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
North American Electric Reliability Corp. (NERC) (OATT Schedule 10-NERC Manual 27, Section 2)	***Charges:*** 2017 rate of $0.0126/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of NERC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the NERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Reliability First Corp. (RFC) (OATT Schedule 10-RFC Manual 27, Section 2)	***Charges:*** 2017 rate of $0.0202/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of RFC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the RFC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Transmission Owner Scheduling, System Control and Dispatch Service (OATT Schedule 1A Manual 27, Section 2)	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. ***Charges:*** Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of $0.0912/MWh based on their energy deliveries including losses and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve. ***Credits:*** The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal $/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	***Sched 1A Charge Summary*** ***Sched 1A Credit Summary*** ***Sched 1A Load Recon Charge Summary***
Reactive Supply and Voltage Control from Generation and Other Sources Service (OATT Schedule 2 Manual 27, Section 3)	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. ***Credits:*** Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements. ***Charges:*** Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	***Reactive Charge Summary***

Regulation and Frequency Response Service (OpAgr Schedules 1-3.2.2, 3.2.2A, 3.3.2, & 3.3.2A and OATT Schedule 3 Manual 28, Section 4)	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. ***Credits:*** Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance) priced at the regulation market capability clearing price. Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance and the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio)) priced at the regulation market performance clearing prices. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost. ***Charges:*** PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). PJM LSEs also have an hourly regulation mileage obligation equal to their adjusted obligation ratio share of the mileage component of the requlation supplied. Hourly charges calculated as adjusted obligations times the regulation market capability and performance clearing prices and the regulation mileage obligation times the regulation market performance clearing price. Additional charges are assessed for any unrecovered cost payments that PJM provides to regulation suppliers and allocated to regulation market purchasers based on their share of any portion of their adjusted obligation in excess of their self-scheduled regulation. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	***Regulation Summary*** ***Regulation Credits*** ***Load Response Regulation Credits*** ***Reg Load Recon Charge Summary***
Synchronized Reserve (OpAgr Schedules 1-3.2.3A & 3.3.5 and OATT Schedule 5 Manual 28, Section 6)	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. ***Credits:*** Generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event when non-synchronized reserve clearing prices are zero receive Tier 1 credits equal to response MWh times synchronized reserve energy premium less its hourly LMP. During hours when the non-synchronized reserve clearing price is non-zero resources receive Tier 1 credits equal to the lesser of the response MWh or the Tier 1 estimate times the applicable reserve zone's Synchronized Reserve Market Clearing Price. Resources receive Tier 2 hourly credits for pool- and self-scheduled synchronized reserve priced at the applicable reserve zone's Tier 2 clearing price. Additional credits provided to pool-scheduled synchronized reserve resources for any portion of synchronized reserve offer plus opportunity cost, energy use cost, and start-up cost not recovered via Synchronized Reserve Market Clearing Price revenues. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total assignments (adjusted for any bilateral synchronized reserve transactions). Tier 1 charges for each participant equal their ratio share of the total Tier 1 credits based on the amount of Tier 1 synchronized reserve applied to their obligation. Tier 2 hourly charges for each participant equal their reserve market's hourly Tier 2 clearing price times the MWh of Tier 2 synchronized reserve self-scheduled that hour toward their obligation plus that which was purchased from that synchronized reserve market, plus their share of any unrecovered costs incurred by assigned Tier 2 resources above the Tier 2 clearing price, plus their share of costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	***Synchronized Reserve Credit Summary*** ***Synchronized Reserve Tier 1 Credits*** ***Synchronized Reserve Tier 2 Credits*** ***Synchronized Reserve Obligation Details*** ***Synchronized Reserve Tier 1 Charge Summary*** ***Synchronized Reserve Tier 2 Charge Summary*** ***Load Response Tier 1 Credits*** ***Load Response Tier 2 Credits*** ***Synchronized Reserve Load Recon Charge Summary***

Non-Synchronized Reserve (OpAgr Schedules 1-3.2.3A.001 & 3.3.5A Manual 28, Section 7)	PJM conducts non-synchronized reserve markets to ensure the capability of generation off-line and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. ***Credits:*** Hourly credits provided to generation resources supplying non-synchronized reserve at the Non-Synchronized Reserve Clearing Price. Additional credits provided to non-synchronized reserve resources for any portion of non-synchronized reserve opportunity costs not recovered via Non-Synchronized Reserve Market Clearing Price revenues. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly non-synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total non-synchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). Hourly charges calculated as adjusted obligations times the Non-Synchronized Reserve Market Clearing Price. Additional charges are assessed for any unrecovered cost payments that PJM provides to non-synchronized reserve suppliers based on adjusted obligation ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	***Non-Synchronized Reserve Summary*** ***Non-Synchronized Reserve Credits*** ***Non-Synchronized Reserve Load Recon Charge Summary***

Day-ahead Scheduling Reserve (OpAgr Schedules 1-3.2.3A.01 and OATT Schedule 6 Manual 28, Section 19)	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. ***Credits:*** Daily credits provided to eligible generator and demand response resources cleared day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price. ***Charges:*** PJM LSEs have an hourly day-ahead scheduling reserve obligation equal to their real-time load (without losses) ratio share of the market's total assignments (adjusted for any bilateral day-ahead scheduling reserve transactions). Total hourly cost of day-ahead scheduling reserve is allocated based on obligation ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	*Day-ahead Scheduling Reserve Summary* *Day-ahead Scheduling Reserve Credits* *Day-ahead Scheduling Reserve Load Recon Charge Summary*

Billing Line Item	Description	Reports
Operating Reserve (OpAgr Schedules 1-3.2.3 & 3.3.3 and OATT Schedule 6 Manual 28, Section 5 and Section 11)	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. ***Day-ahead Credits:*** Daily credits provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP. ***Balancing Credits:*** Daily credits for specified operating period segments provided to eligible pool-scheduled generators, demand response, and import transactions in real-time for any portion of their offer amount in excess of: (1) scheduled MWh times day-ahead bus LMP; (2) MWh deviation from day-ahead schedule times real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any day-ahead scheduling reserve market revenues in excess of offer plus opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs and (7) any applicable reactive services credits. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also provided to generators reduced or suspended by PJM for reliability purposes. ***Day-ahead Charges:*** Total daily cost of operating reserve in the day-ahead market excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares. ***Balancing Charges:*** Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWh); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an daily basis using a $/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	*Operating Reserve Charge Summary* *Operating Reserve Generator Credit Details* *Operating Reserve Lost Opportunity Cost Credits* *Operating Reserve Transaction Credits* *Operating Reserve Generator Deviations* *Operating Reserve Deviation Summary* *Operating Reserve Transaction Credits* *Operating Reserve for Load Response Credit Details* *Operating Reserve for Load Response Deviation Charge Summary* *Operating Reserve for Load Response Charge Allocations* *Regional Balancing Operating Reserve Charge Summary* *Balancing Operating Reserve Load Recon Charge Summary* *CT Lost Opportunity Cost Forfeiture*
Synchronous Condensing (OpAgr Schedule 1-3.2.3 Manual 28, Section 5)	***Credits:*** Daily credits for condensing and energy use costs are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services. ***Charges:*** Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	*Synchronous Condensing Credits* *Synchronous Condensing Charge Summary* *Synchronous Condensing Load Recon Charge Summary*

Billing Line Item	Description	Reports
Reactive Services (OpAgr Schedule 1-3.2.3B Manual 28, Section 5)	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. ***Credits:*** Daily credits are calculated for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services. ***Charges:*** Total daily cost of reactive services and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control is allocated separately for each PJM transmission zone based on real-time load (without losses) ratio shares in the applicable transmission zone. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's $/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	*Reactive Services Credits* *Synchronous Condensing Credits* *Reactive Services Charge Summary* *Reactive Svcs Load Recon Charge Summary*
Black Start Service (OATT Schedule 6A Manual 27, Section 7)	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. ***Credits:*** Monthly credits provided to generators with approved black start revenue requirements. ***Charges:*** Monthly pool-wide black start revenue requirements and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining black start revenue requirements nominated by each zonal Transmission Owner and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing not recovered from point-to-point customers are allocated to the network customers serving load in that transmission zone based on their monthly network service peak load contributions.	*Black Start Charge Summary*
Financial Transmission Rights Auction (OpAgr Schedule 1-7.3.8 Manual 28, Section 16)	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. ***Charges:*** Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price. ***Credits:*** Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	*FTR Auction Charges and Credits*
Auction Revenue Rights (OpAgr Schedule 1-7.4 Manual 28, Section 17)	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. ***Credits:*** Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	*ARR Target Credits*

Billing Line Item	Description	Reports
RPM Auction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	***Credits:*** Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity. ***Charges:*** Each buy bid MW cleared in an incremental auction adjusted by cleared buy bid transactions pays the applicable LDA's resource clearing price. Resource make-whole payments for an incremental auction are also allocated as charges to Market Buyers based on the MW shares of cleared buy bids adjusted by cleared buy bid transactions for the incremental auction. Resource make-whole payments for the base residual auction and the portion of the resource make-whole payment for an incremental auction that would be based on PJM cleared buy bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal Capacity Price.	***RPM Auction Charges and Credits*** ***RPM Auction Make-Whole Charge Summary*** ***RPM Auction Charges*** ***RPM Auction Credits***
Locational Reliability (OATT Att. DD, Section 5.14 Manual 18, Section 9.2)	***Charges:*** Each LSE is charged for their daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.	***Locational Reliability Charge Summary***
Capacity Transfer Rights (OATT Att. DD, Section 5.15 Manual 18, Section 9.3)	To recognize the value of import capability to constrained LDAs, Capacity Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher load charges. ***Credits:*** CTRs equal to the unforced capacity imported into the LDA (less any incremental CTRs) are allocated to LSEs in that LDA based on daily unforced capacity obligations. These MW allocations are priced at the difference between the LDA's clearing price and the unconstrained price.	***CTR Credit Summary***
Incremental Capacity Transfer Rights (OATT Att. DD, Section 5.16, OATT Schedule 12A (b) Manual 18, Section 9.3)	Incremental CTRs are provided to fund for transmission upgrades (not including qualifying transmission upgrades cleared in the Base Residual Auction) that increase import capability into a constrained LDA. Incremental CTRs for Incremental-Rights Eligible Required Transmission Enhancements are determined and allocated as defined in Schedule 12A of the Tariff. ***Credits:*** Incremental CTR MW are priced at the sum of: 1) locational price adder of the sink LDA minus that of the Source LDA from the Base Residual Auction; and 2) locational price adder of the sink LDA minus that of the source LDA from the Second Incremental Auction multiplied by the increase in unforced capacity imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the base unforced capacity imported into the sink LDA. Incremental CTR credits determined for an Incremental-Rights Eligible Required Transmission Enhancement are allocated to the responsible customers that are assigned cost responsibility for the transmission enhancements in accordance with the cost allocations in the appendix to Schedule 12. Responsible customers include Network customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners. Network customers serving load in a responsible zone receive credits in proportion to their network service peak load share in that zone.	***Incremental CTR Credits*** ***Incremental CTR for Required Transmission Enhancement Credits***
Auction Specific MW Transaction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets. ***Charges:*** Sellers are charged for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect. ***Credits:*** Buyers are credited for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect.	***Auction Specific MW Transaction Charges and Credits***

Load Management Compliance Penalty (OATT Att. DD, Section 11 Manual 18, Section 9.1)	Sellers with zonal aggregate committed Demand Resources that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource providers and, potentially, LSEs. This billing is performed on a three-month lag. ***Charges:*** For each non-compliant reduction event, under-compliance MW (on an unforced capacity basis) are charged at the lesser of one divided by the actual number of events during the year or 0.50 of the Weighted Annual Revenue Rate. The Weighted Annual Revenue Rate equals the average rate for all cleared Demand Resources, weighted by the MWs cleared at each price, multiplied by the number of days in the Delivery Year. The total Compliance Penalty Charge for the Delivery Year is capped at the annual revenue received for such resources. ***Credits:*** Revenues from events in a given month are allocated to Demand Resources that reduced in excess of their commitment. Any resource credit by event is capped at their excess MW times $1/5^{th}$ of their Annual Revenue Rate. Revenues above that cap are allocated to LSEs based on their average daily unforced capacity obligations during the month of the event.	*Load Management Compliance Penalty Charges* *Load Management Compliance Penalty Credits* *Load Management Compliance Penalty Residual Credits*
Capacity Resource Deficiency (OATT Att. DD, Section 8 Manual 18, Section 9.1)	Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. ***Charges:*** Each capacity resource's deficiency MW for each day it is deficient pays the daily deficiency rate. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	*Non-Compliance Charge Summary* *Deficiency Credit Summary*
Generation Resource Rating Test Failure (OATT Att. DD, Section 7 Manual 18, Section 9.1)	Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each capacity resource's installed capacity minus its highest rating in the relevant testing period (on an unforced capacity basis) pays a daily deficiency rate which is the weighted average capacity resource clearing price plus the higher of: 1) 0.2 times the weighted average capacity resource clearing price or 2) $20/MW-day; ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	*Non-Compliance Charge Summary* *Deficiency Credit Summary*
Qualifying Transmission Upgrade Compliance Penalty (OATT Att. DD, Section 12 Manual 18, Section 9.1)	Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. ***Charges:*** Capacity market sellers with import capability cleared in a base residual auction based on a qualifying transmission upgrade are charged each day that the upgrade is not in service during the applicable delivery year and the seller does not obtain replacement capacity resources. The import capability MW are charged at the higher of the following rates: 1) two times the locational price adder of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable LDA. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	*Non-Compliance Charge Summary* *Deficiency Credit Summary*
Peak Season Maintenance Compliance Penalty (OATT Att. DD, Section 9 Manual 18, Section 9.1)	Each generation capacity resource must have available unforced capacity during the peak season to satisfy its cleared MW. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each generation capacity resource's cleared MW for each day of the peak season that is out-of-service on a maintenance outage not authorized by PJM pays the daily deficiency rate times (1-EFORd). ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	*Non-Compliance Charge Summary* *Deficiency Credit Summary*
Peak-Hour Period Availability (OATT Att. DD, Section 10 Manual 18, Section 9.1)	To ensure capacity resource availability during critical peak hours, incentives are provided to resources that exceed expected availability and penalties are assessed to those who fall short. This billing is performed in the August billing cycle after the conclusion of the delivery year. ***Charges:*** Net peak period capacity shortfall MW are charged at the weighted average resource clearing price for the applicable LDA (except for FRR capacity that are charged at the LDA's Net CONE). ***Credits:*** Total revenues for the delivery year for each LDA are allocated to resources with peak period excesses based on their excess MW. Since these allocations are capped, any remaining credits are allocated to LSEs that paid a Locational Reliability charge based on their daily unforced capacity obligations.	

Load Management Test Failure (OATT Att. DD, Section 11A Manual 18, Section 9.1)	Sellers with committed Demand Resources that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the December billing cycle for June-December, then it is performed monthly for January-May. ***Charges:*** Net capability testing shortfall MW are charged daily at the weighted annual revenue rate for the applicable zone plus the greater of 0.2 times that weighted annual revenue rate or $20/MW-day. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Load Management Test Failure Charge Summary*** ***Load Management Test Failure Credit Summary***

Billing Line Item	Description	Reports
RTO Start-up Cost Recovery (OATT Attachments H-13 and H-14)	All network customers in the AEP Zone pay AEP (expected to end May 2020). ***Charges:*** Monthly charges to AEP zonal network customers are calculated based on network service peak load contributions at a 2017 rate of $105.0835/MW/year.	*RTO Startup Cost Recovery Charge Summary*
Unscheduled Transmission Service (OpAgr Sch1-5.3a Manual 28, Section 14)	***Charges:*** Hourly charges to NYISO for any costs incurred due to unscheduled use of the PJM transmission system in accordance with the PJM-NYPP Interconnection Agreement Schedule 6.02. ***Credits:*** Total hourly charges are allocated as credits with monthly excess congestion credits.	*Hourly Transmission Congestion Credits*
Ramapo Phase Angle Regulators (OpAgr Schedule 1-5.3b Manual 28, Section 15)	***Credits:*** PJM's share of monthly carrying charges for Ramapo Phase Angle Regulators (PARs) are credited to NYISO in accordance with the NYPP-PJM PARs Facilities Agreement. ***Charges:*** Charges are allocated to PJM Mid-Atlantic transmission owners based on transmission revenue requirement shares.	*Ramapo PAR Charge Summary*
Michigan-Ontario Interface Phase Angle Regulators (OATT Schedule 10)	Schedule 10 recovers the costs allocated to PJM from MISO for a portion of the revenue requirement associated with the ITC Transmission's Phase Angle Regulators (PARs) on the Michigan-Ontario Interface. ***Charges:*** PJM charges each customer using Network Integration and Point-to-Point Transmission Service under this Tariff each month a charge equal to the ITC PARs Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region for the month in which the ITC PARs Rate is being calculated.	*Schedule 10 Michigan-Ontario PAR Charges*
Generation Deactivation (OATT Part V)	Revenues are collected for generators requesting retirement where PJM studies find reliability issues that require the generation to continue operating. Cost allocations to zonal load and firm withdrawal rights are determined by PJM based on the beneficiaries. These responsible customers pay the generation owners a share of the Deactivation Avoidable Cost Rate or the FERC-approved Cost of Service Recovery Rate. Any time that the zonal cost allocations change, notice is provided to the Markets and Reliability Committee, Market Implementation Committee, and Market Settlements Subcommittee prior to the change being implemented. ***Charges:*** Charges are being collected for Dominion Generation resources Yorktown 1 and Yorktown 2 based on a Cost of Service Recovery Rate that is expected to end on September 14, 2017. The monthly charges are allocated on a one month lag in accordance with the following study results: http://www.pjm.com/~/media/planning/gen-retire/zonal-cost-allocation-for-retaining-yorktown-1-and-2-generators.ashx Note that the zonal charges are further allocated based on network service peak load contributions within the applicable zone. Charges are also being collected for RC Cape May Holdings, LLC BL England 2 and 3 generators based on a Reliability Must-Run Rate Schedule that is expected to end April 30, 2019. The monthly charges are allocated on a one month lag in accordance with the following study results: http://www.pjm.com/~/media/planning/gen-retire/2017-2018-zonal-cost-allocation-for-retaining-bl-england-2-and-3-generators.ashx Note that the zonal charges are further allocated based on network service peak load contributions within the applicable zone.	*Generation Deactivation Charge Summary* *Generation Deactivation Refund Charge Summary*
Deferred Tax Adjustment (OATT Attachments H-8A and H-17C)	***Charges:*** Each Network Customer that serves one or more end-use customers taking distribution service from PPL Electric Utilities Corporation or from Duquesne Light Company under its applicable retail tariff on file with the Pennsylvania Public Utility Commission ("PPL Electric Distribution Customers" and/or "Duquesne Electric Distribution Customers") shall pay a Monthly Deferred Tax Adjustment Charge. This charge permits PPL Electric and Duquesne Light to recover a deferred income tax liability that is currently unfunded due to a Pennsylvania Public Utility decision to flow-through to customers certain income tax benefits.	*Deferred Tax Adjustment Charge Summary*

PJM Billing Statement Line Items - Current Recovery in FAC / PSM

ID #	CHARGES	FAC	PSM	ID #	CREDITS	FAC	PSM
Transmission							
1000	Amount Due for Interest on Past Due Charges						
1100	Network Integration Transmission Service			2100	Network Integration Transmission Service		
1101	Network Integration Transmission Service (ATSI Low Voltage)			2101	Network Integration Transmission Service (ATSI Low Voltage)		
1104	Network Integration Transmission Service Offset			2104	Network Integration Transmission Service Offset		
				2106	Non-Zone Network Integration Transmission Service		
1108	Transmission Enhancement			2108	Transmission Enhancement		
1109	MTEP Project Cost Recovery			2109	MTEP Project Cost Recovery		
1110	Direct Assignment Facilities			2110	Direct Assignment Facilities		
1120	Other Supporting Facilities			2120	Other Supporting Facilities		
1130	Firm Point-to-Point Transmission Service			2130	Firm Point-to-Point Transmission Service		
				2132	Internal Firm Point-to-Point Transmission Service		
1133	Firm Point-to-Point Transmission Service Resale			2133	Firm Point-to-Point Transmission Service Resale		
1135	Neptune Voluntary Released Transmission Service (Firm)			2135	Neptune Voluntary Released Transmission Service (Firm)		
1138	Linden Voluntary Released Transmission Service (Firm)			2138	Linden Voluntary Released Transmission Service (Firm)		
1140	Non-Firm Point-to-Point Transmission Service			2140	Non-Firm Point-to-Point Transmission Service		
				2142	Internal Non-Firm Point-to-Point Transmission Service		
1143	Non-Firm Point-to-Point Transmission Service Resale			2143	Non-Firm Point-to-Point Transmission Service Resale		
1145	Neptune Voluntary Released Transmission Service (Non-Firm)			2145	Neptune Voluntary Released Transmission Service (Non-Firm)		
1146	Neptune Default Released Transmission Service (Non-Firm)			2146	Neptune Default Released Transmission Service (Non-Firm)		
1147	Neptune Unscheduled Usage Billing Allocation						
1155	Linden Voluntary Released Transmission Service (Non-Firm)			2155	Linden Voluntary Released Transmission Service (Non-Firm)		
1156	Linden Default Released Transmission Service (Non-Firm)			2156	Linden Default Released Transmission Service (Non-Firm)		
1157	Linden Unscheduled Usage Billing Allocation						
Energy							
1200	Day-ahead Spot Market Energy	X[1]	X[1]				
1205	Balancing Spot Market Energy	X[1]	X[1]				
1210	Day-ahead Transmission Congestion	X[1]	X[1]	2210	Transmission Congestion[4]		
				2211	Day-ahead Transmission Congestion[4]		
1215	Balancing Transmission Congestion	X[1]	X[1]	2215	Balancing Transmission Congestion[4]		
				2217	Planning Period Excess Congestion		
1218	Planning Period Congestion Uplift			2218	Planning Period Congestion Uplift		
1220	Day-ahead Transmission Losses	X[1]	X[1]	2220	Transmission Losses		
1225	Balancing Transmission Losses	X[1]	X[1]				
1230	Inadvertent Interchange						
1240	Day-ahead Economic Load Response			2240	Day-ahead Economic Load Response		
1241	Real-time Economic Load Response			2241	Real-time Economic Load Response		
1242	Day-Ahead Load Response Charge Allocation		X[3]				
1243	Real-Time Load Response Charge Allocation		X[3]				
1245	Emergency Load Response		X[3]	2245	Emergency Load Response		X[3]
1250	Meter Error Correction						
1260	Emergency Energy			2260	Emergency Energy		
Market Administration Costs							
1301	PJM Scheduling, System Control and Dispatch Service - Control Area Administration						
1302	PJM Scheduling, System Control and Dispatch Service - FTR Administration						
1303	PJM Scheduling, System Control and Dispatch Service - Market Support						
1304	PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration						
1305	PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.						
1306	PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center						
1307	PJM Scheduling, System Control and Dispatch Service - Market Support Offset						
1308	PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration						
1309	PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration						
1310	PJM Scheduling, System Control and Dispatch Service Refund - Market Support						
1311	PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration						
1312	PJM Scheduling, System Control and Dispatch Service Refund - Capacity Resource/Obligation Mgmt.						
1313	PJM Settlement, Inc.						
1314	Market Monitoring Unit (MMU) Funding						
1315	FERC Annual Charge Recovery						
1316	Organization of PJM States, Inc. (OPSI) Funding						
1317	North American Electric Reliability Corporation (NERC)						
1318	Reliability First Corporation (RFC)						
1319	Consumer Advocates of PJM States, Inc. (CAPS)						
Ancillary Services							
1320	Transmission Owner Scheduling, System Control and Dispatch Service			2320	Transmission Owner Scheduling, System Control and Dispatch Service		
1330	Reactive Supply and Voltage Control from Generation and Other Sources Service		X[3]	2330	Reactive Supply and Voltage Control from Generation and Other Sources Service		X[3]
1340	Regulation and Frequency Response Service		X[3]	2340	Regulation and Frequency Response Service		X[3]
1350	Energy Imbalance Service			2350	Energy Imbalance Service		
1360	Synchronized Reserve		X[3]	2360	Synchronized Reserve		X[3]

PJM Billing Statement Line Items - Current Recovery in FAC / PSM

ID #	CHARGES	FAC	PSM	ID #	CREDITS	FAC	PSM
1362	Non-Synchronized Reserve		X^3	2362	Non-Synchronized Reserve		X^3
1365	Day-ahead Scheduling Reserve		X^3	2365	Day-ahead Scheduling Reserve		X^3
1370	Day-ahead Operating Reserve			2370	Day-ahead Operating Reserve	X^2	X^2
1371	Day-ahead Operating Reserve for Load Response			2371	Day-ahead Operating Reserve for Load Response		
1375	Balancing Operating Reserve			2375	Balancing Operating Reserve	X^2	X^2
1376	Balancing Operating Reserve for Load Response			2376	Balancing Operating Reserve for Load Response		
1377	Synchronous Condensing		X^3	2377	Synchronous Condensing		X^3
1378	Reactive Services		X^3	2378	Reactive Services		X^3
1380	Black Start Service		X^3	2380	Black Start Service		X^3
1390	Fuel Cost Policy Penalty			2390	Fuel Cost Policy Penalty		
Reconciliations							
1400	Load Reconciliation for Spot Market Energy						
1410	Load Reconciliation for Transmission Congestion						
1420	Load Reconciliation for Transmission Losses			2420	Load Reconciliation for Transmission Losses		
1430	Load Reconciliation for Inadvertent Interchange						
1440	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service						
1441	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund						
1442	Load Reconciliation for Schedule 9-6 - Advanced Second Control Center						
1444	Load Reconciliation for Market Monitoring Unit (MMU) Funding						
1445	Load Reconciliation for FERC Annual Charge Recovery						
1446	Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding						
1447	Load Reconciliation for North American Electric Reliability Corporation (NERC)						
1448	Load Reconciliation for Reliability First Corporation (RFC)						
1450	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service						
1460	Load Reconciliation for Regulation and Frequency Response Service		X^3				
1470	Load Reconciliation for Synchronized Reserve		X^3				
1472	Load Reconciliation for Non-Synchronized Reserve		X^3				
1475	Load Reconciliation for Day-ahead Scheduling Reserve		X^3				
1478	Load Reconciliation for Balancing Operating Reserve						
1480	Load Reconciliation for Synchronous Condensing		X^3				
1490	Load Reconciliation for Reactive Services		X^3				
Financial Transmission Rights							
1500	Financial Transmission Rights Auction			2500	Financial Transmission Rights Auction		
				2510	Auction Revenue Rights		
Capacity							
1600	RPM Auction		X^5	2600	RPM Auction		X^5
1610	Locational Reliability						
				2620	Interruptible Load for Reliability		
				2630	Capacity Transfer Rights		
				2640	Incremental Capacity Transfer Rights		
1650	Auction Specific MW Capacity Transaction			2650	Auction Specific MW Capacity Transaction		
1660	Load Management Compliance Penalty			2660	Load Management Compliance Penalty		
1661	Capacity Resource Deficiency			2661	Capacity Resource Deficiency		
1662	Generation Resource Rating Test Failure			2662	Generation Resource Rating Test Failure		
1663	Qualifying Transmission Upgrade Compliance Penalty			2663	Qualifying Transmission Upgrade Compliance Penalty		
1664	Peak Season Maintenance Compliance Penalty			2664	Peak Season Maintenance Compliance Penalty		
1665	Peak-Hour Period Availability			2665	Peak-Hour Period Availability		
1666	Load Management Test Failure			2666	Load Management Test Failure		
1667	Non-Performance			2667	Bonus Performance		
1670	FRR LSE Reliability			2670	FRR LSE Reliability		
1680	FRR LSE Demand Resource and ILR Compliance Penalty			2680	FRR LSE Demand Resource and ILR Compliance Penalty		
1681	FRR LSE Capacity Resource Deficiency			2681	FRR LSE Capacity Resource Deficiency		
1682	FRR LSE Generation Resource Rating Test Failure			2682	FRR LSE Generation Resource Rating Test Failure		
1683	FRR LSE Qualifying Transmission Upgrade Compliance Penalty			2683	FRR LSE Qualifying Transmission Upgrade Compliance Penalty		
1684	FRR LSE Peak Season Maintenance Compliance Penalty			2684	FRR LSE Peak Season Maintenance Compliance Penalty		
1685	FRR LSE Peak-Hour Period Availability			2685	FRR LSE Peak-Hour Period Availability		
1686	FRR LSE Load Management Test Failure			2686	FRR LSE Load Management Test Failure		
1687	FRR LSE Schedule 9-5			2687	FRR LSE Schedule 9-5		
1688	FRR LSE Schedule 9-6			2688	FRR LSE Schedule 9-6		
1710	PJM/MISO Seams Elimination Cost Assignment			2710	PJM/MISO Seams Elimination Cost Assignment		
1712	Intra-PJM Seams Elimination Cost Assignment			2712	Intra-PJM Seams Elimination Cost Assignment		
1720	RTO Start-up Cost Recovery			2720	RTO Start-up Cost Recovery		
1730	Expansion Cost Recovery			2730	Expansion Cost Recovery		
Miscellaneous							
1900	Unscheduled Transmission Service						
1910	Ramapo Phase Angle Regulators			2910	Ramapo Phase Angle Regulators		
1911	Michigan - Ontario Interface Phase Angle Regulators						
				2912	CT Lost Opportunity Cost Allocation		
1920	Station Power						
1930	Generation Deactivation			2930	Generation Deactivation		

PJM Billing Statement Line Items - Current Recovery in FAC / PSM

ID #	CHARGES	FAC	PSM	ID #	CREDITS	FAC	PSM
1932	Generation Deactivation Refund			2932	Generation Deactivation Refund		
1950	Virginia Retail Administrative Fee			2950	Virginia Retail Administrative Fee		
1952	Deferred Tax Adjustment			2952	Deferred Tax Adjustment		
1955	Deferral Recovery			2955	Deferral Recovery		
1980	Miscellaneous Bilateral			2980	Miscellaneous Bilateral		
1995	PJM Annual Membership Fee						
				2996	Annual PJM Cell Tower		
				2997	Annual PJM Building Rent		
1999	PJM Customer Payment Default						

1 FAC includes allocated amounts from purchase power allocation only; PSM includes allocated amounts from units assigned to non-native sales only.
2 Allocation follows generating unit; if unit is assigned to native load, credit flows to FAC; if unit is assigned to non-native, credit flows to PSM.
3 Per Case No. 2008-00489, total of all ASM charges/credits summed together. If negative, no charge flows to PSM; if positive, net proceed flows thru PSM.
4 Charge type 2210 was transitioned to 2211 and 2215.
5 Per Case No. 2014-00201, net of charge types 1600 and 2600 for East Bend related capacity transation charges/credits flows through PSM.

PJM Billing Statement Line Items - Proposed Recovery in FAC / PSM / and Rider FTR

ID #	CHARGES	FAC	PSM	RIDER FTR	ID #	CREDITS	FAC	PSM	RIDER FTR
Transmission									
1000	Amount Due for Interest on Past Due Charges			X					
1100	Network Integration Transmission Service			X	2100	Network Integration Transmission Service			X
1101	Network Integration Transmission Service (ATSI Low Voltage)			X	2101	Network Integration Transmission Service (ATSI Low Voltage)			X
1104	Network Integration Transmission Service Offset			X	2104	Network Integration Transmission Service Offset			X
					2106	Non-Zone Network Integration Transmission Service			X
1108	Transmission Enhancement			X	2108	Transmission Enhancement			X
1109	MTEP Project Cost Recovery				2109	MTEP Project Cost Recovery			
1110	Direct Assignment Facilities			X	2110	Direct Assignment Facilities			X
1120	Other Supporting Facilities			X	2120	Other Supporting Facilities			X
1130	Firm Point-to-Point Transmission Service			X	2130	Firm Point-to-Point Transmission Service			X
					2132	Internal Firm Point-to-Point Transmission Service			X
1133	Firm Point-to-Point Transmission Service Resale			X	2133	Firm Point-to-Point Transmission Service Resale			X
1135	Neptune Voluntary Released Transmission Service (Firm)			X	2135	Neptune Voluntary Released Transmission Service (Firm)			X
1138	Linden Voluntary Released Transmission Service (Firm)			X	2138	Linden Voluntary Released Transmission Service (Firm)			X
1140	Non-Firm Point-to-Point Transmission Service			X	2140	Non-Firm Point-to-Point Transmission Service			X
					2142	Internal Non-Firm Point-to-Point Transmission Service			X
1143	Non-Firm Point-to-Point Transmission Service Resale			X	2143	Non-Firm Point-to-Point Transmission Service Resale			X
1145	Neptune Voluntary Released Transmission Service (Non-Firm)			X	2145	Neptune Voluntary Released Transmission Service (Non-Firm)			X
1146	Neptune Default Released Transmission Service (Non-Firm)			X	2146	Neptune Default Released Transmission Service (Non-Firm)			X
1147	Neptune Unscheduled Usage Billing Allocation			X					
1155	Linden Voluntary Released Transmission Service (Non-Firm)			X	2155	Linden Voluntary Released Transmission Service (Non-Firm)			X
1156	Linden Default Released Transmission Service (Non-Firm)			X	2156	Linden Default Released Transmission Service (Non-Firm)			X
1157	Linden Unscheduled Usage Billing Allocation			X					
Energy									
1200	Day-ahead Spot Market Energy	X	X						
1205	Balancing Spot Market Energy	X	X						
1210	Day-ahead Transmission Congestion	X	X		2210	Transmission Congestion[5]	X	X	
					2211	Day-ahead Transmission Congestion[5]	X	X	
1215	Balancing Transmission Congestion	X	X		2215	Balancing Transmission Congestion[5]	X	X	
					2217	Planning Period Excess Congestion	X	X	
1218	Planning Period Congestion Uplift	X	X		2218	Planning Period Congestion Uplift	X	X	
1220	Day-ahead Transmission Losses	X	X		2220	Transmission Losses	X	X	
1225	Balancing Transmission Losses	X	X						
1230	Inadvertent Interchange	X	X						
1240	Day-ahead Economic Load Response		X		2240	Day-ahead Economic Load Response		X	
1241	Real-time Economic Load Response		X		2241	Real-time Economic Load Response		X	
1242	Day-Ahead Load Response Charge Allocation		X						
1243	Real-Time Load Response Charge Allocation		X						
1245	Emergency Load Response		X		2245	Emergency Load Response		X	
1250	Meter Error Correction	X	X						
1260	Emergency Energy	X	X		2260	Emergency Energy	X	X	
Market Administration Costs									
1301	PJM Scheduling, System Control and Dispatch Service - Control Area Administration			X					
1302	PJM Scheduling, System Control and Dispatch Service - FTR Administration			X					
1303	PJM Scheduling, System Control and Dispatch Service - Market Support			X					
1304	PJM Scheduling, System Control and Dispatch Service - Regulation Market Administration			X					
1305	PJM Scheduling, System Control and Dispatch Service - Capacity Resource/Obligation Mgmt.			X					
1306	PJM Scheduling, System Control and Dispatch Service - Advanced Second Control Center			X					
1307	PJM Scheduling, System Control and Dispatch Service - Market Support Offset			X					
1308	PJM Scheduling, System Control and Dispatch Service Refund - Control Area Administration			X					
1309	PJM Scheduling, System Control and Dispatch Service Refund - FTR Administration			X					
1310	PJM Scheduling, System Control and Dispatch Service Refund - Market Support			X					
1311	PJM Scheduling, System Control and Dispatch Service Refund - Regulation Market Administration			X					
1312	Mgmt.			X					
1313	PJM Settlement, Inc.			X					
1314	Market Monitoring Unit (MMU) Funding			X					
1315	FERC Annual Charge Recovery			X					
1316	Organization of PJM States, Inc. (OPSI) Funding			X					
1317	North American Electric Reliability Corporation (NERC)			X					
1318	Reliability First Corporation (RFC)			X					
1319	Consumer Advocates of PJM States, Inc. (CAPS)			X					
Ancillary Services									
1320	Transmission Owner Scheduling, System Control and Dispatch Service			X	2320	Transmission Owner Scheduling, System Control and Dispatch Service			X
1330	Reactive Supply and Voltage Control from Generation and Other Sources Service		X		2330	Reactive Supply and Voltage Control from Generation and Other Sources Service		X	
1340	Regulation and Frequency Response Service	X	X		2340	Regulation and Frequency Response Service	X	X	
1350	Energy Imbalance Service	X	X		2350	Energy Imbalance Service	X	X	
1360	Synchronized Reserve	X	X		2360	Synchronized Reserve	X	X	
1362	Non-Synchronized Reserve		X		2362	Non-Synchronized Reserve		X	
1365	Day-ahead Scheduling Reserve		X		2365	Day-ahead Scheduling Reserve		X	
1370	Day-ahead Operating Reserve	X	X		2370	Day-ahead Operating Reserve	X	X	
1371	Day-ahead Operating Reserve for Load Response		X		2371	Day-ahead Operating Reserve for Load Response		X	
1375	Balancing Operating Reserve	X	X		2375	Balancing Operating Reserve	X	X	
1376	Balancing Operating Reserve for Load Response		X		2376	Balancing Operating Reserve for Load Response		X	
1377	Synchronous Condensing	X	X		2377	Synchronous Condensing	X	X	
1378	Reactive Services	X	X		2378	Reactive Services	X	X	
1380	Black Start Service		X		2380	Black Start Service		X	
1390	Fuel Cost Policy Penalty				2390	Fuel Cost Policy Penalty			

Reconciliations									
1400	Load Reconciliation for Spot Market Energy	X	X						
1410	Load Reconciliation for Transmission Congestion	X	X						
					2415	Balancing Transmission Congestion Load Reconciliation	X	X	
1420	Load Reconciliation for Transmission Losses	X	X		2420	Load Reconciliation for Transmission Losses	X	X	
1430	Load Reconciliation for Inadvertent Interchange	X	X						
1440	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service			X					
1441	Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund			X					
1442	Load Reconciliation for Schedule 9-6 - Advanced Second Control Center			X					
1444	Load Reconciliation for Market Monitoring Unit (MMU) Funding			X					
1445	Load Reconciliation for FERC Annual Charge Recovery			X					
1446	Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding			X					
1447	Load Reconciliation for North American Electric Reliability Corporation (NERC)			X					
1448	Load Reconciliation for Reliability First Corporation (RFC)			X					
1450	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service			X					
1460	Load Reconciliation for Regulation and Frequency Response Service	X	X						
1470	Load Reconciliation for Synchronized Reserve	X	X						
1472	Load Reconciliation for Non-Synchronized Reserve		X						
1475	Load Reconciliation for Day-ahead Scheduling Reserve		X						
1478	Load Reconciliation for Balancing Operating Reserve	X	X						
1480	Load Reconciliation for Synchronous Condensing	X	X						
1490	Load Reconciliation for Reactive Services	X	X						
Financial Transmission Rights									
1500	Financial Transmission Rights Auction	X	X		2500	Financial Transmission Rights Auction	X	X	
					2510	Auction Revenue Rights	X	X	
Capacity									
1600	RPM Auction		X		2600	RPM Auction		X	
1610	Locational Reliability								
					2620	Interruptible Load for Reliability			
					2630	Capacity Transfer Rights			
					2640	Incremental Capacity Transfer Rights			
1650	Auction Specific MW Capacity Transaction				2650	Auction Specific MW Capacity Transaction			
1660	Load Management Compliance Penalty				2660	Load Management Compliance Penalty			
1661	Capacity Resource Deficiency				2661	Capacity Resource Deficiency			
1662	Generation Resource Rating Test Failure				2662	Generation Resource Rating Test Failure			
1663	Qualifying Transmission Upgrade Compliance Penalty				2663	Qualifying Transmission Upgrade Compliance Penalty			
1664	Peak Season Maintenance Compliance Penalty				2664	Peak Season Maintenance Compliance Penalty			
1665	Peak-Hour Period Availability				2665	Peak-Hour Period Availability			
1666	Load Management Test Failure				2666	Load Management Test Failure			
1667	Non-Performance				2667	Bonus Performance			
1670	FRR LSE Reliability				2670	FRR LSE Reliability			
1680	FRR LSE Demand Resource and ILR Compliance Penalty				2680	FRR LSE Demand Resource and ILR Compliance Penalty			
1681	FRR LSE Capacity Resource Deficiency				2681	FRR LSE Capacity Resource Deficiency			
1682	FRR LSE Generation Resource Rating Test Failure				2682	FRR LSE Generation Resource Rating Test Failure			
1683	FRR LSE Qualifying Transmission Upgrade Compliance Penalty				2683	FRR LSE Qualifying Transmission Upgrade Compliance Penalty			
1684	FRR LSE Peak Season Maintenance Compliance Penalty				2684	FRR LSE Peak Season Maintenance Compliance Penalty			
1685	FRR LSE Peak-Hour Period Availability				2685	FRR LSE Peak-Hour Period Availability			
1686	FRR LSE Load Management Test Failure				2686	FRR LSE Load Management Test Failure			
1687	FRR LSE Schedule 9-5				2687	FRR LSE Schedule 9-5			
1688	FRR LSE Schedule 9-6				2688	FRR LSE Schedule 9-6			
1710	PJM/MISO Seams Elimination Cost Assignment				2710	PJM/MISO Seams Elimination Cost Assignment			
1712	Intra-PJM Seams Elimination Cost Assignment				2712	Intra-PJM Seams Elimination Cost Assignment			
1720	RTO Start-up Cost Recovery				2720	RTO Start-up Cost Recovery			
1730	Expansion Cost Recovery				2730	Expansion Cost Recovery			
Miscellaneous									
1900	Unscheduled Transmission Service								
1910	Ramapo Phase Angle Regulators				2910	Ramapo Phase Angle Regulators			
1911	Michigan - Ontario Interface Phase Angle Regulators								
					2912	CT Lost Opportunity Cost Allocation			
1920	Station Power								
1930	Generation Deactivation	X	X		2930	Generation Deactivation	X	X	
1932	Generation Deactivation Refund				2932	Generation Deactivation Refund			
1950	Virginia Retail Administrative Fee				2950	Virginia Retail Administrative Fee			
1952	Deferred Tax Adjustment				2952	Deferred Tax Adjustment			
1955	Deferral Recovery				2955	Deferral Recovery			
1980	Miscellaneous Bilateral	X[1]	X[1]	X[1]	2980	Miscellaneous Bilateral	X[1]	X[1]	X[1]
1995	PJM Annual Membership Fee								
					2996	Annual PJM Cell Tower			
					2997	Annual PJM Building Rent			
1999	PJM Customer Payment Default								

1 Misc Bilateral is an agreement between parties regarding discrepancies - This will depend on the detail of the settlement by PJM BLI and recovery will follow the PJM BLI

PJM BILLING LINE ITEMS CURRENTLY RECOVERED UNIFORMLY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	Included In FAC By KY Power Co (2014-00450)	Included In FAC By East KY Power Coop (2014-00451)	Included in FAC By Duke KY (2014-00454)	PSC Allow Recovery through FAC?
1	1200	Day-ahead Spot Market Energy	Day-ahead energy market net hourly PJM Interchange MWh are calculated for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Day-ahead Charges: Net day-ahead PJM Interchange is charged hourly at the PJM-wide day-ahead system energy price. Charges are positive for net buyers and negative for net sellers of day-ahead spot market energy.	Yes	Yes[1]	Yes[3]	Approved
2	1205	Balancing Spot Market Energy	Real-time energy market net hourly PJM Interchange MWh are calculated for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. Balancing Charges: Net real-time deviations from day-ahead PJM Interchange is charged hourly at the PJM-wide real-time system energy price. Charges may be positive or negative depending on the direction of the real-time deviation from day-ahead interchange.	Yes	Yes[1]	Yes[3]	Approved
3	1220	Day-ahead Transmission Losses	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). An hourly day-ahead Net Loss Bill is calculated as day-ahead withdrawal charges (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at applicable buses' day-ahead loss prices) minus day-ahead injection credits (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at applicable buses' day-ahead loss prices). Hourly day-ahead implicit loss charges equal the day-ahead Net Loss Bill. Hourly explicit loss charges for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable).	Yes[4]	Yes[2]	Yes[3]	Approved
4	1225	Balancing Transmission Losses	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). An hourly balancing Net Loss Bill is calculated as balancing withdrawal charges (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead and real-time load, without losses, and sale transactions priced at the applicable buses' real-time loss prices) minus balancing injection credits (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead and real-time generation and purchase transactions priced at the applicable buses' real-time loss prices). Hourly balancing implicit loss charges equal the balancing Net Loss Bill. Hourly explicit loss charges for balancing energy transactions equal any real-time deviations from day-ahead transaction MWh times the difference between real-time sink and source loss prices and assessed to the buyer (or point-to-point transmission customer, if applicable).	Yes[4]	Yes[2]	Yes[3]	Approved

Please note that any Charge that is recovered / passed through the FAC necessitates that the corresponding Credit and Reconciliation be recovered / passed through the FAC.

1. EKPC uses the PJM MSRS hourly data reports (Charge Codes 1200 and 1205) to determine the purchase and sales mw and includes the portion applicable to purchases in the FAC.
2. EKPC takes the amount from the invoice for charge codes 1210, 1215, 1220, 1225 and allocates it between purchases & sales and includes the balancing on generation portion in the FAC.
3. DEK uses the PJM hourly data to determine the hourly purchases and hourly sales MWhrs and multiplies it by the hourly LMP which includes the energy price, marginal loss price, and transmission marginal congestion price.
   Therefore, none of the BLIs are taken directly from the invoice.
4. Approved in Case 2007-00522. The PSC found that the recovery of the charges and credits related to marginal line losses are the same types of costs that were previously included in KPCo's FAC calculations.

PJM BILLING LINE ITEMS CURRENTLY RECOVERED NON-UNIFORMLY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	Included In FAC By KY Power Co (2014-00450)	Included In FAC By East KY Power Coop (2014-00451)	Included in FAC By Duke KY (2014-00454)	PSC Allow Recovery through FAC?
1	1210	Day-ahead Transmission Congestion	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders.	No	Yes[1]	Yes[2]	Approved
2	2210	Transmission Congestion Credit	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders.	No	Yes	No	Approved
3	1215	Balancing Transmission Congestion	The increased energy costs due to redispatch during hours when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs, and the revenues collected are allocated to FTR holders.	No	Yes[1]	Yes[2]	Approved
4	1218	Planning Period Congestion Uplift	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements.	No	Yes	No	Approved
5	2217	Planning Period Excess Congestion Credit	Total congestion revenues allocated as hourly credits based on FTR target allocations. Excess hourly congestion credits are used to proportionately eliminate target deficiencies in other hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period with any excess at the end of the planning period allocated proportionately to FTR holders with net positive FTR target allocations for that planning period. Any deficiencies remaining at the end of a planning period are eliminated by reallocating all planning period FTR congestion revenues among FTR holders to yeild a uniform ratio of deficiency.	No	Yes	No	Approved
6	2218	Planning Period Congestion Uplift Credit	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements.	No	Yes	No	Approved
7	1230	Inadvertent Interchange	Charges: PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares.	No	Yes	No	Approved
8	1250	Meter Error Correction	Charges: Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	No	Yes	No	Approved
9	1260	Emergency Energy	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas.	No	Yes	No	Approved

PJM BILLING LINE ITEMS CURRENTLY RECOVERED NON-UNIFORMLY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	Included In FAC By KY Power Co (2014-00450)	Included In FAC By East KY Power Coop (2014-00451)	Included in FAC By Duke KY (2014-00454)	PSC Allow Recovery through FAC?
10	2260	Emergency Energy Credit	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. Credits: Hourly net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	No	Yes	No	Approved
11	1420	Load Reconciliation for Transmission Losses	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag.	Yes	Yes	No	Approved
12	2220	Transmission Losses Credit	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving 31% of their allocation).	Yes	Yes	No	Approved
13	2420	Load Reconciliation for Transmission Losses	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving 31% of their allocation) on a two-month billing lag.	Yes	Yes	No	Approved
14	1370	Day-ahead Operating Reserve Charge	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Total daily cost of operating reserve in the day-ahead market excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares.	No	Yes	No	Approved
15	2370	Day-ahead Operating Reserve Credit	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Daily credits provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP.	No	Yes	Yes	Approved
16	1375	Balancing Operating Reserve	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWh); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports.	No	Yes	No	Approved

PJM BILLING LINE ITEMS CURRENTLY RECOVERED NON-UNIFORMLY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	Included In FAC By KY Power Co (2014-00450)	Included In FAC By East KY Power Coop (2014-00451)	Included in FAC By Duke KY (2014-00454)	PSC Allow Recovery through FAC?
17	2375	Balancing Operating Reserve Credit	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources and that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. Daily credits for specified operating period segments provided to eligible pool-scheduled generators, demand response, and import transactions in real-time for any portion of their offer amount in excess of: (1) scheduled MWh times day-ahead bus LMP; (2) MWh deviation from day-ahead schedule times real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any day-ahead scheduling reserve market revenues in excess of offer plus opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs and (7) any applicable reactive services credits. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also provided to generators reduced or suspended by PJM for reliability purposes.	No	Yes	Yes	Approved
		Please note that any Charge that is recovered / passed through the FAC necessitates that the corresponding Credit and Reconciliation be recovered / passed through the FAC.					
		1. EKPC takes the amount from the invoice for charge codes 1210, 1215, 1220, 1225 and allocates it between purchases & sales and includes the balancing on generation portion in the FAC.					
		2. DEK uses the PJM hourly data to determine the hourly purchases and hourly sales MWhrs and multiplies it by the hourly LMP which includes the energy price, marginal loss price, and transmission marginal congestion price.					
		Therefore, none of the BLIs are taken directly from the invoice.					

ADDITIONAL ELIGIBLE PJM BILLING LINE ITEMS NOT CURRENTLY RECOVERED THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
	RECONCILIATION BLIs FOR ITEMS CURRENTLY RECOVERED THROUGH THE FAC			
1	1400	Load Reconciliation for Spot Market Energy	Retail load schedules with reconciliation data (in kWh) provided by the applicable electric distribution company (EDC) are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the Balancing Spot Market Energy charge (1205). The Balancing Spot Market Energy charge trues up the Day ahead Sport Market Energy charge (1200). Both 1200 and 1205 are recovered through the FAC currently.
2	1410	Load Reconciliation for Transmission Congestion	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the Balancing Transmission Congestion charge (1215) recovered through FAC currently. Balancing Transmission Congestion (1215) trues up Day Ahead Transmission Congestion (1210).
3	1430	Load Reconciliation for Inadvertent Interchange	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the inadvertent Interchange charge (1230) recovered through FAC currently.
4	1478	Load Reconciliation for Balancing Operating Reserve	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an daily basis using a $/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	The reconciliation process is a required component of PJM participation. On a two month lag, this charge is a true up and corresponds to the Balancing Operating Reserve (1375) recovered through FAC currently.
	ANCILIARY SERVICE BLIs*			
5	1340	Regulation and Frequency Response Service Charge	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. Charges: PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). PJM LSEs also have an hourly regulation mileage obligation equal to their adjusted obligation ratio share of the mileage component of the regulation supplied. Hourly charges calculated as adjusted obligations times the regulation market capability and performance clearing prices and the regulation mileage obligation times the regulation market performance clearing price. Additional charges are assessed for any unrecovered cost payments that PJM provides to regulation suppliers and allocated to regulation market purchasers based on their share of any portion of their adjusted obligation in excess of their self-scheduled regulation.	Regulation refers to a specific resource (generator) with appropriate telecommunications, control and response capability to increase or decrease its energy output in response to a regulating control signal to control for frequency deviations. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide regulating and frequency response services unless it is online and consuming fuel.

ADDITIONAL ELIGIBLE PJM BILLING LINE ITEMS NOT CURRENTLY RECOVERED THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
6	2340	Regulation and Frequency Response Service Credit	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. Credits: Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance) priced at the regulation market capability clearing price. Generators and demand resources receive hourly credits for pool- and self-scheduled regulation (with consideration of the resource's performance and the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio)) priced at the regulation market performance clearing prices. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost.	This is the same type of credit that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide regulating reserves unless it is online and consuming fuel.
7	1460	Load Reconciliation for Regulation and Frequency Response Service	Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable electric distribution company (EDC) are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	The reconciliation process is a required component of PJM participation. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide regulating and frequency response services unless it is online and consuming fuel. Corresponds to 1340.
8	1350	Energy Imbalance Service Charge	Each Transmission Customer must purchase Energy Imbalance service through PJM. For each Network Customer and Point-to-Point Transmission Customers. Energy Imbalance service is considered PJM Interchange and is therefore accounted for as Spot Market energy using hourly Locational Marginal Prices (LMP).	Billing based on real-time LMP which is an energy based cost type that consumes fuel.
9	2350	Energy Imbalance Service Credit	Energy Imbalance service is provided when a difference occurs between the scheduled and the actual delivery of energy over a single hour to a load that is located within PJM. PJM must offer this service when Transmission Service is used to serve load located with PJM. Currently PJM has none of these types of transmission customers.	Billing based on real-time LMP which is an energy based cost type that consumes fuel.
10	1360	Synchronized Reserve Charge	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total assignments (adjusted for any bilateral synchronized reserve transactions). Tier 1 charges for each participant equal their ratio share of the total Tier 1 credits based on the amount of Tier 1 synchronized reserve applied to their obligation. Tier 2 hourly charges for each participant equal their reserve market's hourly Tier 2 clearing price times the MWh of Tier 2 synchronized reserve self-scheduled that hour toward their obligation plus that which was purchased from that synchronized reserve market, plus their share of any unrecovered costs incurred by assigned Tier 2 resources above the Tier 2 clearing price, plus their share of costs of those Tier 2 resources assigned in addition to that which was estimated prior to a given hour.	Synchronized reserve is the reserve capability required to enable an area to restore its tie lines to the pre-contingency state within 10 minutes of a contingency that causes an imbalance between load and generation. During normal operation, these reserves must be provided by increasing energy output on electrically synchronized equipment, by reducing load on pumped storage hydroelectric facilities or reducing demand. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide synchronized reserves unless it is online and consuming fuel.

ADDITIONAL ELIGIBLE PJM BILLING LINE ITEMS NOT CURRENTLY RECOVERED THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
11	2360	Synchronized Reserve Credit	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. Generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event when non-synchronized reserve clearing prices are zero receive Tier 1 credits equal to response MWh times synchronized reserve energy premium less its hourly LMP. During hours when the non-synchronized reserve clearing price is non-zero resources receive Tier 1 credits equal to the lesser of the response MWh or the Tier 1 estimate times the applicable reserve zone's Synchronized Reserve Market Clearing Price. Resources receive Tier 2 hourly credits for pool and self-scheduled synchronized reserve priced at the applicable reserve zone's Tier 2 clearing price. Additional credits provided to pool-scheduled synchronized reserve resources for any portion of synchronized reserve offer plus opportunity cost, energy use cost, and start-up cost not recovered via Synchronized Reserve Market Clearing Price revenues.	This is the same type of credit that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide synchronized reserves unless it is online and consuming fuel.
12	1470	Load Reconciliation for Synchronized Reserve	Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	Corresponds to 1360. The reconciliation process is a required component of PJM participation. This is the same type of cost that was included in a utility's FAC filings prior to joining an RTO. A fossil fuel generator cannot provide synchronized reserves unless it is online and consuming fuel.
13	1377	Synchronous Condensing Charge	Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares.	This service / function was self supplied prior to participation in PJM. This payment is appropriate to recover through the FAC because energy (fuel) is required to operate a synchronous condenser. A synchronous condenser is a machine that operates without mechanical load whose purpose is to supply or absorb reactive power on the transmission system for voltage control purposes.
14	2377	Synchronous Condensing Credit	Daily credits for condensing and energy use costs are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services.	Corresponds to 1377. This is the same type of credit that was included in a utility's FAC filings prior to joining an RTO. Energy (fuel) is required to operate a synchronous condenser. A synchronous condenser is a machine that operates without mechanical load whose purpose is to supply or absorb reactive power on the transmission system for voltage control purposes.
15	1480	Load Reconciliation for Synchronous Condensing	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	Corresponds to 1377. On a two month lag, this is a true up for actual synchronous condenser performance.
16	1378	Reactive Services Charge	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Charges: Total daily cost of reactive services and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control is allocated separately for each PJM transmission zone based on real time load (without losses) ratio shares in the applicable transmission zone.	Reactive power is the product of voltage and the out-of-phase component of alternating current. It's measured in VARs and is produced by capacitors and overexcited generators and absorbed by reactors and other inductive devices. Energy (fuel) is required to run these machines.

ADDITIONAL ELIGIBLE PJM BILLING LINE ITEMS NOT CURRENTLY RECOVERED THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
17	2378	Reactive Services Credit	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Credits: Daily credits are calculated for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services.	Reactive power is the product of voltage and the out-of-phase component of alternating current. It's measured in VARs and is produced by capacitors and overexcited generators and absorbed by reactors and other inductive devices. Energy (fuel) is required to run these machines.
18	1490	Load Reconciliation for Reactive Services	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or compensated for their lost opportunity costs. Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's $/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	Corresponds to 1378. The reconciliation process is a required component of PJM participation.
	CONGESTION HEDGING RELATED BLIs			
19	1500	Financial Transmission Rights Auction	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price.	Related to congestion charges. Generators are redispatched out of economic order to relieve congestion. This results in additional fuel cost.
20	2500	Financial Transmission Rights Auction	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	Related to congestion charges. Generators are redispatched out of economic order to relieve congestion. This results in additional fuel cost.
21	2510	Auction Revenue Rights	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers. Credits: Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	Related to congestion charges. Generators are redispatched out of economic order to relieve congestion. This results in additional fuel cost.
		* See Anciliary Services Handout		
		Please note that any Charge that is recovered / passed through the FAC necessitates that the corresponding Credit and Reconciliation be recovered / passed through the FAC.		

ADDITIONAL PJM BILLING LINE ITEMS NOT ELIGIBLE FOR RECOVERY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
1	1240	Day-Ahead Economic Load Response Charge	For day-ahead and real-time economic load response, the Curtailment Service Provider's (CSP's) Load Serving Entity (LSE) is charged the difference between LMP and the retail rate, as applicable, times the MWh reduction.	Load response; not includable in FAC
2	2240	Day Ahead Economic Load Response Credit	Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWh times LMP (minus retail rate, as applicable).	Load response; not includable in FAC
3	1241	Real Time Economic Load Response Charge	For day-ahead and real-time economic load response, the CSP's LSE is charged the difference between LMP and the retail rate, as applicable, times the MWh reduction.	Load response; not includable in FAC
4	2241	Real-Time Economic Load Response Credit	Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWh times LMP (minus retail rate, as applicable).	Load response; not includable in FAC
5	1242	Day-Ahead Load Response Charge Allocation Charge	This is a socialized piece of the load response, like emergency energy purchases	Load response; not includable in FAC
6	1243	Real Time Load Response Charge Allocation Charge	This is a socialized piece of the load response, like emergency energy purchases	Load response; not includable in FAC
7	1245	Pre-Emergency and Emergency Load Response Charge	For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	Load response; not includable in FAC : Denied in EKPC Case
8	2245	Emergency Load Response Credit	Emergency load response credits are provided to Curtailment Service Providers (CSPs) equal to the reduced MWh times LMP (minus retail rate, as applicable).	Load response; not includable in FAC : Denied in EKPC Case
9	1371	Day-Ahead Operating Reserve for Load Response	The daily total cost of Day-ahead Operating Reserve which includes Day-ahead Load Response Operating Reserve payments are allocated and charged to PJM Members in proportion to their cleared day-ahead demand and decrement bids plus their cleared day-ahead exports.	Load response; not includable in FAC
10	2371	Day-Ahead Operating Reserve for Load Response	Total payments to Economic Load Response Participants for cleared day-ahead demand reduction bids with an offer price equal to or greater than the threshold price established under the Net Benefits Test that follow the dispatch instructions of the Office of the Interconnection will not be less than the total value of the demand reduction bid.	Load response; not includable in FAC
11	1376	Balancing Operating Reserve for Load Response	The daily total cost of Balancing Load Response Operating Reserve Payments is allocated and charged to PJM Members in proportion to their real-time deviations from day-ahead schedules and generator deviations.	Load response; not includable in FAC
12	2376	Balancing Operating Reserve for Load Response	In cases where the demand reduction follows dispatch as instructed by the Office of the Interconnection, and the demand reduction offer price is equal to or greater than the threshold price established under the Net Benefits Test, payment will not be less than the total value of the demand reduction bid, including any submitted shut-down costs.	Load response; not includable in FAC

ADDITIONAL PJM BILLING LINE ITEMS NOT ELIGIBLE FOR RECOVERY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
13	1320	Transmission Owner Scheduling, System Control and Dispatch Service	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. Charges: Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of $0.0912/MWh based on their energy deliveries including losses and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve.	Not fuel related. Charges for operation of Transmission Operator's control centers.
14	2320	Transmission Owner Scheduling, System Control and Dispatch Service	Credits: The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff.	Not fuel related. Revenues for operation of a control center.
15	1450	Load Reconciliation for Transmission Owner Scheduling, System Control and Dispatch Service	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal $/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	Not fuel related. Revenues for operation of a control center.
16	1330	Reactive Supply and Voltage Control from Generation and Other Sources Service Charge	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. Charges: Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	Not fuel related. Charges for reactive power.
17	2330	Reactive Supply and Voltage Control from Generation and Other Sources Service Credit	Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements.	Not fuel related. FERC Formula Driven revenue for reactive power.
18	1380	Black Start Services Charge	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. Monthly pool-wide black start revenue requirements and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system.	Not fuel related. Charges for Black Start Capability.
19	2380	Black Start Service Credit	Monthly credits provided to generators with approved black start revenue requirements.	Not fuel related. Revenues for possessing Black Start Capability.
20	1362	Non-Synchronized Reserve Charge	PJM conducts non-synchronized reserve markets to ensure the capability of **generation off-line** and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly nonsynchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total nonsynchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). Hourly charges calculated as adjusted obligations times the Non-Synchronized Reserve Market Clearing Price. Additional charges are assessed for any unrecovered cost payments that PJM provides to non-synchronized reserve suppliers based on adjusted obligation ratio shares.	Not fuel related. This service is provided by an off-line generator that is not consuming fuel. There can, but not always, be an energy market opportunity cost to a generator providing non-synchronized reserve.
21	2362	Non-Synchronized Reserve Credit	PJM conducts non-synchronized reserve markets to ensure the capability of **generation off-line** and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. Hourly credits provided to generation resources supplying non-synchronized reserve at the Non-Synchronized Reserve Clearing Price. Additional credits provided to non-synchronized reserve resources for any portion of nonsynchronized reserve opportunity costs not recovered via Non-Synchronized Reserve Market Clearing Price revenues.	Not fuel related. This service is provided by an off-line generator that is not consuming fuel. There can, but not always, be an energy market opportunity cost to a generator providing non-synchronized reserve.

ADDITIONAL PJM BILLING LINE ITEMS NOT ELIGIBLE FOR RECOVERY THROUGH THE FAC

	PJM Billing Line Item	PJM Billing Line Item Description	Detailed PJM Billing Line Item Description	FAC Approval Justification
22	1472	Load Reconciliation for Non-Synchronized Reserve	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	Not fuel related. This service is provided by an off-line generator that is not consuming fuel. There can, but not always, be an energy market opportunity cost to a generator providing non-synchronized reserve.
23	1365	Day-Ahead Scheduling Reserve Charge	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. Charges: PJM LSEs have an hourly day-ahead scheduling reserve obligation equal to their real-time load (without losses) ratio share of the market's total assignments (adjusted for any bilateral day-ahead scheduling reserve transactions). Total hourly cost of day-ahead scheduling reserve is allocated based on obligation ratio shares.	Not fuel related. Generators providing this service may or may not run in the real-time. If the unit does not run then there is no fuel consumed. If a unit provides this service and also runs in the real-time then the cost of fuel consumed will be compensated via the Balancing Spot Market Energy (1205) and other charge types.
24	2365	Day-Ahead Scheduling Reserve Credit	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. Credits: Daily credits provided to eligible generator and demand response resources cleared day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price.	Not fuel related. Generators providing this service may or may not run in the real-time. If the unit does not run then there is no fuel consumed. If a unit provides this service and also runs in the real-time then the cost of fuel consumed will be compensated via the Balancing Spot Market Energy (1205) and other charge types.
25	1475	Load Reconciliation for Day-Ahead Scheduling Reserve	Reconciliation Charges: Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	Not fuel related. Generators providing this service may or may not run in the real-time. If the unit does not run then there is no fuel consumed. If a unit provides this service and also runs in the real-time then the cost of fuel consumed will be compensated via the Balancing Spot Market Energy (1205) and other charge types.
	PJM Market Administration Fees:			
26	1301 through 1318	Charges	The charges for PJM scheduling, system control, and dispatch service are allocated on an unbundled basis in accordance with Schedule 9: "PJM Interconnection, L.L.C. Administrative Services" of the PJM Open Access Transmission Tariff. The PJM scheduling, system control and dispatch service charge in any month to any PJM Member is the sum of the charges calculated for that Member under the Service Categories defined in Schedule 9	Not fuel related.
27	1440 through 1448	Reconciliation Charges	Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis.	Not fuel related.

Direct Testimony of
John A. Verderame

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

JOHN A. VERDERAME

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John A. Verderame, and my business address is 526 S. South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Progress, Inc. (Duke Energy Progress) as Managing Director, Power Trading and Dispatch. Duke Energy Progress is the utility formerly known as Progress Energy Inc., (Progress Energy) located in North and South Carolina. As part of the merger integration process, Duke Energy Progress now provides various administrative and other services to the regulated affiliated companies within Duke Energy Corporation (Duke Energy Corp.), including Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company).

Q. PLEASE DESCRIBE BRIEFLY YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Arts degree in Economics from the University of Rochester in 1983, and a Master's in Business Administration in Finance from Rutgers University in 1985. I have worked in the energy industry for 16 years. Prior to that, from 1986 to 2001, I was a Vice President in the United States (US) Government Bond Trading Groups at the Chase Manhattan Bank and Cantor Fitzgerald. My responsibilities as a US Government Securities Trader included acting as the Firm's market maker in US Government Treasury securities. I joined Progress Energy, in 2001, as a Real-Time Energy Trader. My responsibilities as a Real-Time Energy Trader included managing the real-time energy position of the

Progress Energy regulated utilities. In 2005, I was promoted to Manager of the Power Trading group. My role as manager included responsibility for the short-term capacity and energy position of the Progress Energy regulated utilities in the Carolinas and Florida.

In 2012, upon consummation of the merger between Duke Energy Corp. and Progress Energy, Progress Energy became Duke Energy Progress and I was promoted to my current position.

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

A. Yes. I have previously testified in the Company's Fuel Adjustment Clause (FAC) proceedings as well as other cases that have involved the Company's participation in energy and capacity markets.

Q. PLEASE SUMMARIZE YOUR DUTIES AS MANAGING DIRECTOR, POWER TRADING AND DISPATCH.

A. As Managing Director, Power Trading and Dispatch of Duke Energy Progress, I am responsible for Power Trading and Generation Dispatch on behalf of the Duke Energy's regulated utilities in the Carolinas, Florida, Indiana, Ohio, and Kentucky. I am primarily responsible for Duke Energy Kentucky's generation dispatch, unit commitment, 24-hour real-time operations, and plant communications related to short-term generating maintenance planning. I lead the team responsible for managing the Company's capacity position with respect to meeting its Fixed Resource Requirement (FRR) obligation as a member of PJM Interconnection, L.L.C. (PJM), for the submission of the Company's supply offers and demand bids in PJM's day-ahead and real-time electric energy (collectively Energy Markets) and ancillary services markets (ASM), as well as managing the Company's short-term and long-term supply position to ensure that the Company has adequate economic resources committed to serve its retail customers' electricity needs. In that respect, my teams are also responsible for any financial hedging done to mitigate exposure to short-term energy prices and congestion risks.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. I provide an overview of the Company's generating resources to meet its customer load obligations and provide safe, reliable and adequate service. I briefly describe Duke Energy Kentucky's resource planning process that is used to ensure it continues to meet its Kentucky customer's load requirements. I then discuss the Company's participation in PJM as it pertains to the capacity markets and discuss the customer benefits that the Company's PJM membership provides. I then describe the recent changes in PJM and those proposals currently under consideration by PJM and the Federal Energy Regulatory Commission (FERC) that will impact both the Company and Duke Energy Kentucky's customers going forward and how the Company is addressing those changes. I support the Company's proposal to update and streamline its Profit Sharing Mechanism, Rider PSM. Finally, I sponsor Filing Requirement (FR) 16(7)(h)(7) and certain forecasted financial data that I provided to Duke Energy Kentucky witness Mr. Robert "Beau" Pratt for his use in preparing the Company's forecast.

II. OVERVIEW OF DUKE ENERGY'S CURRENT GENERATING RESOURCES

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF HOW DUKE ENERGY KENTUCKY MEETS ITS KENTUCKY LOAD OBLIGATIONS.

A. Duke Energy Kentucky currently owns and operates approximately 1,062 net installed megawatts (MW) of generating capacity, provided by two assets. Base load requirements are met by the East Bend Unit 2 Generating Station (East Bend). East Bend is an approximate 600 megawatt (MW) (net rating) coal-fired base load unit located along the Ohio River in Boone County, Kentucky. The Company's peaking requirements are met with the Woodsdale Generating Station (Woodsdale). Woodsdale is a six-unit natural gas-fired combustion turbine (CT) with approximately 462 MW (net summer rating) located in Trenton, Ohio. The net ratings represent the amount of power that the Company can dispatch from the plants after some portion of the gross power output is used to power the plant machinery. These assets are dispatched into PJM, which maintains functional control of the transmission system within its footprint including the Duke Energy Ohio/Kentucky system.

Q. ARE YOU FAMILIAR WITH THE INTEGRATED RESOURCE PLANNING PROCESS FOR DUKE ENERGY KENTUCKY?

A. Yes. Duke Energy Kentucky files its integrated resource plan (IRP) approximately every three years. The Company filed its last IRP with the Commission in Case No. 2014-00273, and the Commission issued an Order on September 23, 2015, accepting the IRP. Although this IRP provided a snapshot of Duke Energy

Kentucky's resource planning at that point in time, IRP planning is a dynamic process that is periodically updated. Duke Energy Kentucky's next IRP is scheduled to be filed with the Commission in June 2018.

Q. PLEASE GENERALLY DESCRIBE THE IRP PLANNING PROCESS.

A. The IRP planning process assesses various supply-side, demand-side and emission compliance alternatives to develop a long-term, cost-effective portfolio to provide customers with reliable service at reasonable costs. The IRP planning process involves various assumptions such as future energy prices, future environmental compliance requirements and reliability constraints.

The Duke Energy's load forecasting group develops the load forecast by: (1) obtaining service area economic forecasts primarily from Moody's Analytics; (2) preparing an energy forecast by applying statistical analysis to certain variables such as number of customers, economic measures, energy prices, weather conditions, *etc.;* and (3) developing monthly peak demand forecasts by statistically analyzing weather data. The Company updates the load forecasts on a regular basis and the updated load forecasts are used for all modeling analysis. It is important to note that while Duke Energy Kentucky develops internal load forecasts for system planning purposes, the actual load forecast and the Duke Energy Kentucky PJM load obligation, which includes peak coincidence factors and system reserve requirements is calculated by PJM, and can differ slightly from the Company's internal forecast.

Q. PLEASE EXPLAIN HOW THE COMPANY MODELS THE DISPATCH OF ITS GENERATING STATIONS.

A. The Company utilizes a commercially available production cost model (GenTrader) to develop the forecast utilized in the Company's semi-annual FAC filings, as well as its position management in PJM. 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. Other inputs include projected fuel costs for each unit, planned outages, forced outage rates, the market value for emission allowances, the market price for power, and the Company's load forecast for native load customers. The GenTrader model simulates the economic dispatch of the Company's generating fleet and projects market dispatch generation sales to PJM and power purchases from PJM to meet the forecasted load for future periods. For the time periods forecasted, the model provides projections of how generating units are expected to operate, including projections of fuel consumption and emissions. The model also allocates the generation between native and non-native load and projects energy purchases when economical.

Q. WHAT RELIABILITY CONSTRAINT ASSUMPTIONS ARE NECESSARY TO DEVELOP AN IRP?

A. The Company must determine a minimum reserve margin, an annual estimate of the number of loss of load hours and an annual estimate of the expected unserved energy. For planning purposes, Duke Energy Kentucky estimates the number and expected timing of forced outages, using the definition of forced outages contained in the Commission's FAC regulation, 807 KAR 5:056, as follows: nonscheduled losses of generation or transmission that (1) require substitute power for a continuous period in excess of six hours; and (2) result from faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance.

The Company also factors the current known scheduled outages for future PJM delivery years in order to determine what, if any, reserves are needed.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PLANNING RESERVE MARGIN AND HOW IT IS CALCULATED.

A. The planning reserve margin used for 2017 resource planning is 14.5 percent. The IRP models utilize the full capacity of the unit ratings to perform dispatch, so the reserve margin needs to be developed on an installed capacity rating, calculated as follows:

1. The PJM Forecast Pool Requirement (FPR_{UCAP}) is calculated using the PJM equivalent demand forced outage rate ($EFOR_d^{PJM}$) and the PJM installed reserve margin (RM_{ICAP}^{PJM}). The FPR_{UCAP} is 8.92 percent.
2. FPR_{UCAP} is translated to a Duke Energy Kentucky (DEK) installed-capacity-basis reserve margin ($RM_{ICAP}^{COINCIDENT}$) using the 5-year average $EFOR_d^{DEK}$ (8.92 percent). Based on this calculation, $RM_{ICAP}^{COINCIDENT}$ is 19.6 percent.
3. For long range planning, PJM's forecast assumes that the Duke Energy Ohio-Kentucky zone is 95.8 percent coincident with the PJM peak. Applying this coincidence factor to Duke Energy Kentucky's 19.6

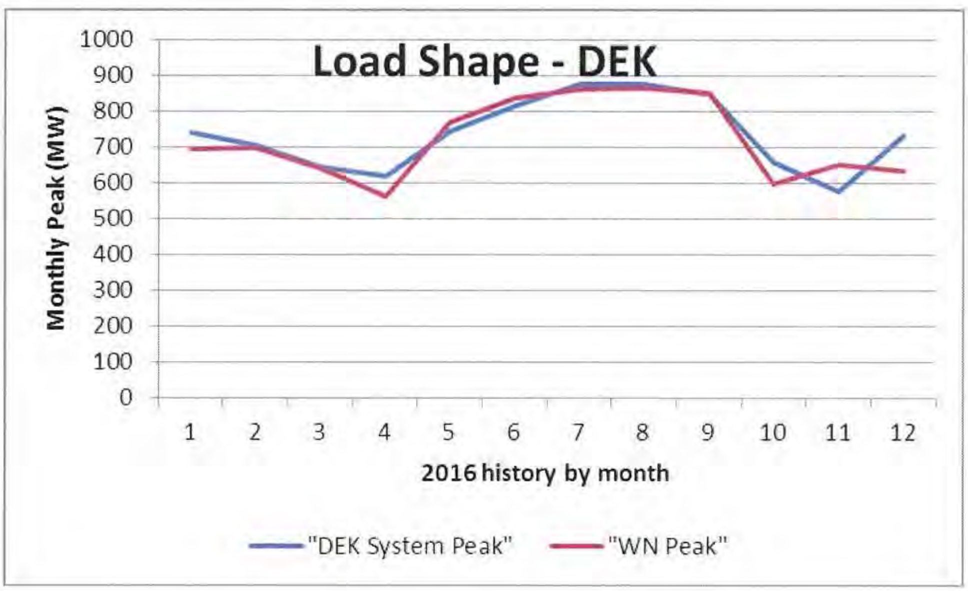
percent $RM_{ICAP}^{COINCIDENT}$ results in a planning reserve margin of 14.5 percent.[1]

The projected reserve margins for Duke Energy Kentucky are shown below:

Year	Projected Reserves (MW)	Projected Reserve Margin (percent)
2017	250	31
2018	247	30
2019	246	30
2020	240	29
2021	243	30

Q. WHAT ARE THE COMPANY'S LOAD REQUIREMENTS?

A. The chart below depicts the shape of the Company's monthly load obligations for the twelve months ended December 2016.



[1] Acronyms and PJM specific terms are defined in the PJM Glossary available at http://www.pjm.com/Glossary#index_R . (Last visited on August 21, 2017).

Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts and high case demand and energy forecasts for the current year and the next four years are projected as follows:

Duke Energy Kentucky – Native Load Forecast				
	Demand – MW		Energy - MWH	
	Base	High	Base	High
2017	845	930	4,056,669	4,388,994
2018	842	926	4,077,811	4,435,970
2019	843	927	4,087,481	4,463,377
2020	843	927	4,081,266	4,464,419
2021	842	926	4,063,929	4,451,687

Q. DOES DUKE ENERGY KENTUCKY CURRENTLY HAVE SUFFICIENT CAPACITY TO MEET ITS KENTUCKY CUSTOMER LOAD OBLIGATIONS?

A. Duke Energy Kentucky currently has sufficient capacity to meet its load obligations, however, short-term capacity purchases may be necessary in order to maintain sufficient reserves and meet its capacity obligations in PJM. Ahead in my testimony, I describe how Duke Energy Kentucky proposes to address any short-term capacity shortfalls and how those costs are proposed to be recovered. Currently, there are no planned base load or peaking capacity additions needed to meet native load requirements over the next ten years. Likewise, there are no planned unit retirements to occur in next ten years.

III. DUKE ENERGY KENTUCKY'S PARTICIPATION IN PJM

Q. PLEASE DESCRIBE THE PJM CAPACITY MARKET.

A. PJM's capacity market is called RPM, which is an acronym for Reliability Pricing Model. The purpose of RPM is to provide a market construct that enables PJM to secure adequate generation resources to meet the reliability needs of the regional transmission organization (RTO). The RPM construct and the associated rules regarding how PJM members participate in the PJM capacity market is described within the PJM Open Access Transmission Tariff (OATT) and Reliability Assurance Agreement (RAA). The PJM capacity market operates on a planning period that spans twelve months beginning June 1st and ending May 31st of each subsequent year (Delivery Year). In PJM, the capacity market structure is intended to provide transparent forward market signals that support generation and infrastructure investment. There are two ways for a PJM member to participate in the RPM capacity structure: 1) through the RPM baseline procurement auctions; or 2) as a self-supply FRR entity. The baseline procurement auction is called a base residual auction (BRA). BRAs are conducted three years in advance of the actual Delivery Year in order to allow bidders to complete construction of projects that clear the BRA. The PJM capacity market is designed to provide incentives for the development of generation, demand response, energy efficiency, and transmission solutions through capacity market payments.

Another important component of RPM is that price signals are locational, and designed to recognize and quantify the geographical value of capacity. PJM divides the RTO into multiple sub-regions called locational delivery areas (LDAs) in order to model the locational value of generation.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY CURRENTLY PARTICIPATES IN THE PJM CAPACITY CONSTRUCT.

A. Consistent with the Commission's Order in Case No. 2010-00203, Duke Energy Kentucky is an FRR Entity in PJM. As a condition of Duke Energy Kentucky becoming a member of PJM, the Commission required the Company to participate in PJM as an FRR entity until such time as it received Commission approval to participate in the PJM capacity auctions. To date, the Company has not requested such permission, but continues to evaluate the merits of exiting the FRR obligation and becoming a full RPM auction participant.

Q. PLEASE BREIFLY EXPLAIN PJM'S FRR PROCESS.

A. The PJM OATT and RAA specify the obligations and compensation to load serving entities (LSE) for supplying capacity. The FRR process is an alternative means for a PJM LSE such as Duke Energy Kentucky to satisfy its customer capacity obligation under the PJM RAA. Under the FRR construct, an LSE must annually submit a preliminary three-year forward, and a final current year FRR capacity plan that meets a PJM defined customer capacity obligation (FRR Plan). The FRR Plan must identify the unit-specific generating or demand response resources that will be providing the MWs of capacity that will fulfill the LSE's customer obligation. FRR allows the LSE to match its customer reliability requirement to its own generation, demand response, energy efficiency and/or transmission resources, while still being permitted to sell some or all of its excess supply into RPM. Duke Energy Kentucky would face severe penalties and limitations on its ability to choose the FRR option if PJM were to deem either its initial or final FRR plans to be insufficient or it's generation otherwise non-compliant with PJM requirements.

Q. PLEASE EXPLAIN WHAT BEING AN FRR ENTITY MEANS FOR DUKE ENERGY KENTUCKY.

A. As an FRR entity, Duke Energy Kentucky must secure and commit unit-specific generation resources to meet the full load capacity requirements for all of its customers in advance of the PJM BRA through its FRR Plan. The FRR Plan is forward-looking in that it covers the Delivery Year three years into the future. For example, as part of its most recent FRR plan submitted in 2017, Duke Energy Kentucky must own or contract and commit the unit specific generation resources to satisfy its forecasted load requirements for the period from June 1, 2020, through May 31, 2021. Presently, the load requirements include both the forecasted load of Duke Energy Kentucky's customers, as well as the reserve requirement mandated by PJM.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE PHRASE UNIT-SPECIFIC GENERATION RESOURCES.

A. A unit-specific generation resource, as the phrase implies, simply means a specific generating resource that meets the eligibility requirements defined by PJM. PJM eligible resources include both physical and demand-side management resources. Duke Energy Kentucky must identify the specific generation resources it owns or has contracted for to provide capacity to meet its entire Delivery Year FRR obligation. Unit-specific capacity is distinguishable from the more "generic" buy-bid capacity that may be purchased through the BRA or incremental auctions of PJM. The capacity product available for purchase in those auctions is not directly tied to a specific generator, so it cannot, in itself, be used to satisfy an FRR plan obligation. While sellers in the BRA identify the generation resource offered into the auction, the end product is not so specific. The entire generator performance obligation in the BRA is to PJM, not the purchaser of the buy-bid capacity. From the purchaser's perspective, buy-bid capacity has guaranteed deliverability and performance by PJM. This is distinguishable from the FRR entity where the performance obligation of generation committed to FRR plans is the responsibility of the FRR entity.

As such, Duke Energy Kentucky has similar performance risk to RPM entities, but less flexibility to adjust its plan to account for changes in its resource requirements between the BRA and the Delivery Year than an RPM participant who can simply buy and sell capacity to meet its needs through the BRA.

Q. HAVE THERE BEEN ANY RECENT SHIFTS IN DUKE ENERGY KENTUCKY'S ACCESS TO UNIT-SPECIFIC GENERATION RESOURCES?

A. Yes. In the most recently conducted PJM Base Residual Auction, for the 2020/2021 Delivery Year, capacity in the Duke Energy Ohio Kentucky (DEOK) zone cleared with a LDA adder of $53.47/ MW-day to the $76.53/ MW-day general clearing price known as "Rest of RTO." The total clearing price for the DEOK zone was $130/ MW-day. While there is no guarantee that DEOK zone capacity will continue to clear at a premium to the more generic capacity in the RTO, this zonal separation does create the potential that Duke Energy Kentucky's access to unit-specific capacity could be constrained and even priced at a premium. This loss of liquidity exists regardless of whether Duke Energy Kentucky remains an FRR entity or moves at some point to full RPM participation for as long as the zonal separation exists. Because Duke Energy Kentucky's resources generally match expected load obligation for the planning period, continued investment in the Company's existing generating assets for dedicated use in its FRR plan is a crucial piece of the Company's strategy to serve customers. As such, deviations from the plan driven by either change to load requirements, resource capability or resource unforced capacity could impact costs, and potentially drive deficiencies in FRR Plans.

Q. HAVE THERE BEEN ANY RECENT AND SIGNIFICANT DEVELOPMENTS SINCE THE COMPANY'S LAST BASE RATE CASE THAT HAS CHANGED DUKE ENERGY KENTUCKY'S POWER PROCUREMENT PRACTICES AS IT PERTAINS TO ITS OPERATION IN PJM?

A. Yes. Since the Company's last base electric rate case, the Company moved from the Midwest Independent System Operator, now known as the Midcontinent Independent System Operator, (MISO) to PJM, became the sole owner of East Bend, retired its Miami Fort Unit 6 generating station, and has seen PJM adopt new rules pertaining to capacity that is permitted to be included in its wholesale markets.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY EXITING MISO AND JOINING PJM.

A. At the time of the last rate case, Duke Energy Kentucky was a member of MISO. Effective January 1, 2012, and with Commission authorization, Duke Energy Kentucky, along with its parent company, Duke Energy Ohio, left MISO and became a member of PJM.[2]

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S BECOMING THE SOLE OWNER OF EAST BEND AND EXPLAIN WHY THIS WAS SIGNIFICANT.

A. Effective December 30, 2014, Duke Energy Kentucky became the sole owner of East Bend, having completed its purchase of the remaining 31 percent interest from Dayton Power and Light (DP&L). The purchase of East Bend was primarily driven by the Company's need to retire its Miami Fort Unit 6 Generating Station due to the Mercury and Air Toxics Standard (MATS). Miami Fort Unit 6 was an unscrubbed, coal-fired generating station that could not be retrofitted to meet MATS in a cost-effective manner. The station was retired effective June 1, 2105.

The acquisition of DP&L's share of East Bend represents additional capacity and energy that is being dedicated to Duke Energy Kentucky's customers.

[2] *In the Matter of the Application of Duke Energy Kentucky, Inc., for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment,* Case No. 2010-00203, (Ky.P.S.C. Dec. 22, 2010).

However, it also represents a significant change to the Company's generation portfolio profile. The significance of this purchase and retirement is that, together, the two transactions result in a shift in the Company's base load generation portfolio. Once MF6 was retired, East Bend became the Company's only source of base load generation and its only coal-fired station. While East Bend is a reliable and reasonable cost unit, the increased reliance of this unit and the consequent decrease in resource diversity translated into a different exposure to short-term power prices when the station is not operating due to either forced or scheduled maintenance outages. This portfolio change potentially impacts the Company's strategies in both the PJM capacity and energy markets.

Q. HOW DOES DUKE ENERGY KENTUCKY MANAGE THE RISKS OF THIS EXPOSURE FOR ITS CUSTOMERS?

A. Duke Energy Kentucky operates under a Commission–approved Back-Up Power Supply Plan. The Commission approved the Company's most recent Back-Up Power Supply Plan on May 31, 2017 in Case No. 2017-00117.

Q. PLEASE BRIEFLY SUMMARIZE THE COMPANY'S BACK-UP SUPPLY PLAN.

A. Duke Energy Kentucky conducted a thorough analysis of back-up supply opportunities that were available to select what the Company believes appropriately balances the competing interests of finding the most reasonable and reliable solution for customers that is at the lowest possible cost, to obtain back-up power. The Company's strategy is to continue to manage the risks through the PJM daily energy market during forced outages and use fixed forward contract purchases during scheduled outages. This mitigates the risk of price spikes during scheduled outages because the price for back-up power would be fixed.

The Company's strategy provides the flexibility to optimize the actual outage schedule under changing power market and unit availability conditions through the liquid energy markets. Duke Energy Kentucky can make its forward contract purchase a few months in advance of the scheduled outages, without paying a premium to lock in the prices for a three-year time period. If prices appear to be increasing, the plan provides the flexibility to make the forward contract purchases for long-term periods. If prices are flat or falling, the Company can postpone these purchases. The Company's plan provides flexibility to modify executed forward contract positions if scheduled outage dates are modified, by utilizing the liquidity of the Intercontinental Exchange (ICE) to unwind existing contracts and purchase new contract to match new scheduled outage dates. The Company continues to examine business interruption insurance products to complement its risk management strategy. Duke Energy Kentucky has been using this strategy to successfully manage risks in the energy markets since approximately 2006. History has shown that the Company has been capable of managing these energy risks for its customers.

Q. PLEASE EXPLAIN THE RECENT CHANGES TO THE CAPACITY MARKET CONSTRUCT THAT PJM HAS IMPLEMENTED.

A. In a stated effort to improve the reliability of generating resources in the PJM footprint, PJM has redesigned the RPM construct with the newly coined "Capacity Performance" construct. In doing so, PJM is redefining its capacity products and proposing new performance-based incentives and assessments for non-performance. With Capacity Performance, PJM is adopting a "no-excuses" policy in order to improve reliability.[3] Specifically, PJM established two classes of capacity, "Capacity Performance" Capacity and, for a limited transitional period, "Base Capacity." Also during the transitional period the current annual capacity product will continue to exist for FRR participants.

Q. WHAT IS THE DISTINCTION THAT PJM HAS CREATED FOR CAPACITY PERFORMANCE RESOURCES VERSUS THE PRE-CAPACITY PERFORMANCE ANNUAL CAPACITY PRODUCT?

A. Complying capacity performance resources must be capable of sustained, predictable operation that provides energy and reserves during performance assessment hours throughout the Delivery Year. Performance assessment hours will be determined in real-time based on system conditions. They are not pre-determined, but are anticipated to occur during seasonal peak periods. Capacity performance resources are subject to non-performance assessments during emergency conditions throughout the entire Delivery Year. Base Capacity resources are required to meet the Capacity Performance standard from June through September. Base Capacity will no longer be a Capacity Market product after the transition period. Capacity Performance resources will be required to be available to PJM during periods of high load demand or system emergency, or

[3] *See e.g.,* PJM Press release, May 24, 2016; describing Capacity Performance "the new no excuses" standard. *Available at* http://www.pjm.com/~/media/about-pjm/newsroom/2016-releases/20160524-rpm-auction-results-for-2019-20-news-release.ashx (Last visited August 15, 2017).

face substantial non-performance assessments. Conversely, over-performance will be rewarded with performance-based bonuses.

Q. WHEN WILL THE CAPACITY PERFORMANCE MODEL BECOME FULLY IMPLEMENTED IN PJM?

A. In this new construct, PJM established the goal of transitioning all capacity in the PJM footprint to Capacity Performance by the 2020-2021 Delivery Year. In other words, by June 1, 2020, all capacity purchased on behalf of load through RPM or eligible for inclusion in FRR capacity plans must meet the Capacity Performance criteria.

When PJM achieves full transition to Capacity Performance for the 2020-2021 Delivery Year, every resource in the PJM footprint that is not on a PJM-approved planned outage will be obligated to be available for PJM dispatch. The obligation extends during any hour that PJM determines there to be a compliance hour throughout the entire delivery year. Compliance hours are generally set during periods of capacity or operational stress on the PJM system; and are expected by PJM to average approximately thirty hours per year over time.

Q. WHY DID PJM TAKE THIS ACTION TO IMPLEMENT A CAPACITY PERFORMANCE CONSTRUCT?

A. During the winter months of 2013 through 2014, much of the country experienced a severe cold weather event known as the Polar Vortex where temperatures dropped to historically low levels. This weather event also saw demands, and subsequently prices for energy rise due to constrained availability of resources and fuel. PJM alone experienced forced outage rates exceeding 20 percent. PJM determined the drivers behind these outage rates to be mechanical outages due to extreme cold and demand or weather driven fuel unavailability.

In a concerted effort to avoid a repeat of resource scarcity and reliability concerns, PJM filed with FERC, and was approved to implement, the Capacity Performance construct. The Capacity Performance construct is a substantial rewrite to the existing PJM capacity market design. PJM's intent was to drive generation owners to make investments to fortify reliability of their capacity and to enhance energy market supply by both increasing the financial rewards for compliant capacity value and the risk exposure to non-performance.

Q. WHEN DID THE CAPACITY PERFORMANCE RULES GO INTO EFFECT?

A. PJM described a transitional period to achieve 100 percent Capacity Performance over four years, some years for which it had already conducted the three-year forward base auctions under the old construct. PJM has conducted transitional auctions at increasing percentages of Capacity Performance for the 2016-2017 Delivery Year through the 2019-2020 Delivery Years. Generation included in FRR Plans must eventually meet Capacity Performance requirements, and be eligible for the same performance bonuses and subject to the same non-performance assessments. FERC granted a limited Capacity Performance transition period for FRR entities like Duke Energy Kentucky that includes an exemption and step-up towards 100 percent Capacity Performance compliance for all FRR Plan resources in the 2018-2019 Delivery Year. Following the transitional percentages applied to the general market, Duke Energy Kentucky has since filed a preliminary FRR Plan for the 2019-2020 Delivery Year that includes 80 percent of its obligation as Capacity Performance capacity. The preliminary FRR Plan that Duke Energy Kentucky filed this year, for the 2020-2021 Delivery Year required 100 percent Capacity Performance capacity.

Q. HOW WOULD YOU CLASSIFY THE CURRENT DUKE ENERGY KENTUCKY RESOURCES IN TERMS OF PJM CAPACITY PERFORMANCE COMPLIANCE AND RESPONSE?

A. PJM Capacity Performance compliance does not have a strict or bright line set of guidelines to determine whether or not it complies. The best a utility can do is manage the risks and make appropriate and prudent investments to maintain and if possible, enhance the reliability of its assets to reduce the likelihood of the asset not being able to perform when called upon during a PJM-determined event. That said, there are some minimum strategies that Duke Energy Kentucky can take in terms of ensuring there is a reliable source of fuel, and maintaining regular and proactive maintenance schedules and activities.

In my opinion, East Bend currently meets the minimum requirements of a Capacity Performance resource in that it is a coal-fired facility that maintains a significant reserve of fuel stored on-site. The Company is taking proactive steps to invest in the maintenance of East Bend through "asset hardening" strategies designed to reduce the possibility and likelihood of forced outages.

In my opinion, the Woodsdale facility does not currently meet minimum Capacity Performance requirements due to its lack of fuel certainty. Fuel certainty is a minimum requirement to meet Capacity Performance expectations. The primary fuel at Woodsdale is natural gas delivered under a non-firm delivery contract. In the event that natural gas was unavailable at the site, due to delivery limitations such as operational flow orders on the natural gas pipeline, the station would not be able to meet an immediate demand for energy from PJM. Due to its low capacity factor, Woodsdale does not have contracted firm natural gas transportation. It is simply uneconomic to maintain a firm transportation contract for natural gas at a peaking facility that only was intended and designed to operate during system peaks. While there is very limited propane storage capability at the site, this capacity is insufficient to sustain Woodsdale's continuous operation for more than a few hours, and it is not operationally feasible to expand or replenish propane supplies. Thus, propane is no longer a viable solution for Woodsdale to prudently meet Capacity Performance expectations and the Company must take action to ensure there is a reliable, yet cost-effective fuel supply for the station. The Company has proposed the construction of a new dual fuel oil system for Woodsdale that is currently before the Commission in Case No. 2017-00186. The Company is anticipating completing the dual fuel oil system construction and in-service for several of the Woodsdale units during the rate case test year.

Q. PLEASE EXPLAIN POTENTIAL IMPACTS TO THE COMPANY AND CUSTOMERS OF CAPACITY PERFORMANCE.

A. The generation assets that the Company has invested in are sound and dependable. Duke Energy Kentucky continues to invest in and maintain these assets so that they remain reliable resources and continue to provide benefits to Duke Energy Kentucky's customers. Because fuel certainty is an integral component of meeting

Capacity Performance requirements, these expenses will include capital expenditures in dual fuel capability or other costs to ensure generation unit availability, as well as potential upgrades at generation stations designed to mitigate, to the greatest extent possible, exposure to the significant assessments for non-performance. Other anticipated responses to Capacity Performance risks could include the onsite maintenance of critical long lead time replacement part inventories that could reduce exposure to prolonged outages during periods where PJM is likely to initiate a Capacity Performance event.

Q. DO YOU BELIEVE THE CHANGES THAT PJM HAS MADE ARE BENEFICIAL TO DUKE ENERGY KENTUCKY AND ITS CUSTOMERS?

A. PJM has recognized a reliability issue in its footprint, and is acting in good faith to improve reliability of electric supply. The Capacity Performance changes are intended to incentivize investment in generating resources through enhancing the value of capacity meeting the performance guidelines and through the implementation of severe consequences for non-performance. To the extent that these changes improve reliability and cost efficiency in the PJM footprint, Duke Energy Kentucky's customers certainly benefit.

Q. PLEASE DESCRIBE ANY CHANGES TO THE WHOLESALE ELECTRIC POWER MARKETS THAT ARE ANTICIPATED TO OCCUR WITHIN THE NEXT TWO YEARS THAT COULD AFFECT DUKE ENERGY KENTUCKY'S POWER PROCUREMENT PRACTICES.

A. From a macro level perspective, the Company believes that the energy and electricity sector continues to go through an extraordinary period of change. This change is primarily driven by shifts in load growth patterns, commodity price relationships, the move towards sustainable generation, and increasing regulatory uncertainty. Continued low price natural gas is driving a transition in the traditional concept of "base load generation." As coal-fired generation continues to retire, the natural gas and intermittent resources connecting to the grid, both in front of and behind the meter, drive potential impacts on how grid operators will reliably meet demands, and the investments that will be required in energy resources and grid infrastructure and modernization. It remains to be seen what extent the Trump administration will have on the arc of environmental regulation; but that uncertainty itself will be a challenge to utilities such as Duke Energy Kentucky.

There are several FERC or PJM initiatives under way that have the potential to impact Duke Energy Kentucky customers directly over the next two years. Briefly, examples of these initiatives include: 1) Potential changes to PJM energy offer price caps and offer flexibility; 2) changes to applicability and exemptions to the PJM Minimum Offer Price Rule; 3) changes to how fast start and intermittent resources such as batteries and demand response are accounted for and compensated in the capacity and energy markets; and 4) impacts of potential changes to the Capacity Performance construct as PJM evaluates the effectiveness of capacity performance credits and non-performance assessments in achieving stated goals as Capacity Performance reaches full transition.

The Company believes that the PJM energy markets will continue to function as they do today; however, wholesale energy and capacity price volatility will likely experience upward pressure. Drivers behind this increased volatility include pricing impacts from new environmental regulations as they become effective, trends towards a more renewable and efficient generation mix, and structural market changes implemented by PJM.

Q. CONSIDERING THE CHANGES IN THE WHOLESALE PJM MARKETS, INCLUDING BOTH POTENTIAL RISKS AND REWARDS, DO YOU BELIEVE DUKE ENERGY KENTUCKY'S CUSTOMERS STILL BENEFIT FROM THE COMPANY'S MEMBERSHIP IN PJM?

A. Yes. Duke Energy Kentucky's customers benefit significantly from PJM's centrally dispatched RTO construct. PJM dispatches generation in broad consideration of total RTO cost minimization, the benefits of which are directly passed to customers in the form of energy alternatives to owned generation. The approximately 180,000 MWs of generating capacity in PJM's footprint provides a significant benefit in terms of reliability and provides Duke Energy Kentucky with access to the most efficient generation providing energy. Further, these markets maximize the opportunity for non-native sales from the Company's generation, the majority proceeds of which flow back to Duke Energy Kentucky's customers through a credit on their bills. PJM's focus is on maintaining and improving reliability across its entire system, which directly translates to more efficient and reliable access to electric resources to serve Kentucky demand. With that said, the Company is proposing some changes in this case to adapt to the changes in the wholesale markets related to both opportunities for rewards and potential for risks for customers through the Company's continued ownership and operation of coal and natural gas-fired generating assets dedicated to serving its customers.

IV. <u>CHANGES TO THE PROFIT SHARING MECHANISM</u>

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO ADAPT ITS PROFIT SHARING MECHANISM, RIDER PSM.

A. Duke Energy Kentucky witness, William Don Wathen Jr., explains the Company's proposal in greater detail. In summary, the Company is proposing to expand the mechanism to include all eligible net revenues (costs and credits) available through the wholesale electricity markets, as well as, all net revenues for renewable energy credits (RECs) sales that are attributed to the Company's ownership and dedication of generating resources towards its Kentucky customers. The Company is also proposing to simplify the sharing calculation process for ease of administration and adjust the sharing allocations between customers and the Company. Finally, the Company is proposing to include short-term capacity purchases necessary to meet its FRR plan obligations as well as any tariffed capacity co-generation purchases including from qualified facilities as is required under the Public Utilities Regulatory Policy Act (PURPA).

Q. PLEASE DESCRIBE THE CATEGORIES OF NET PROCEEDS FROM OFF-SYSTEM SALES THAT CURRENTLY INCLUDED IN THE RIDER PSM.

A. Today, the PSM includes sharing of profits on off-system,(*i.e.,* non-native) power sales and ancillary services, the net profits on sales of emission allowances (EAs) and net margins on capacity transactions related to the acquisition of 100 percent of East Bend. The off-system power sales include all the net proceeds for non-native energy sales into the day-ahead and real-time PJM wholesale energy markets.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO EXPAND THE RIDER PSM TO INCLUDE ALL NET PROCEEDS FROM THE WHOLESALE ELECTRICITY MARKETS ATTRIBUTABLE TO THE COMPANY'S OWNERSHIP AND DEDICATION OF GENERATING RESOURCES TO KENTUCKY CUSTOMERS.

A. The Company is proposing to expand the categories of eligible net proceeds to include any net sales (costs and credits) available through wholesale markets that are attributable to the Company's ownership and dedication of generating assets to serve its Kentucky customers. This would include PJM's capacity, energy, ancillary services, or any future markets.

The Company is proposing to include any necessary short-term (one year or less in duration) capacity purchases undertaken to meet its FRR obligation in PJM or sales made during the three-year planning horizon. The Company will continue to follow the existing IRP process as well as the Commission's Certificate of Public Convenience and Necessity rules and regulations for any construction of major generating capacity. Cost recovery through Rider PSM is merely a stop-gap or bridge to allow the Company to meet its FRR capacity requirements through short-term (one-year in length or less duration) capacity products during the three-year planning horizon, more efficiently or cost effectively than through construction of or long term contracting for generation.

The Company is also expanding Rider PSM to include any RECs that the Company is able to monetize in the REC markets. Duke Energy Kentucky has proposed to construct three small solar facilities in Case No. 2017-00155. The Company proposes to expand the PSM to include any net proceeds for REC sales. If the Commonwealth of Kentucky were to ever adopt a renewable portfolio standard, any RECs that had to be purchased would also clear through Rider PSM until such time as the Company proposed and the Commission approved another mechanism. However, for now, with the Company anticipating approximately 7 MWs of solar coming on line in late-2017, these resources will be generating RECs that the Company would be able to sell. The net proceeds would then flow through the sharing percentages in Rider PSM. The Company is proposing to use Rider PSM to net out all off-system sales in a fair and transparent manner.

The Company is proposing to move the net proceeds from sales of any EAs from Rider PSM to the Company's Environmental Surcharge Mechanism (ESM). Currently, customers receive 100 percent of the net sales of EAs. That arrangement will continue through the ESM.

Q. EXPLAIN THE BASIS FOR PROPOSING TO INCLUDE SHORT-TERM CAPACITY PURCHASES IN RIDER PSM

A. As stated earlier in my testimony, Duke Energy Kentucky owns or controls generation resources that generally just meet customer load and reserve requirements. In other words, the Company has not over- or under-invested in generation assets. Currently, there is no provision for recovery of short-term capacity costs incurred during periods where available resources do not meet forecasted customer obligations. The Company has in the past occasionally made capacity purchases in the bilateral market to meet customer obligations, and proposes going forward, to pass those short-term costs (and revenues from sales) through the Rider PSM. The short-term capacity market can be an invaluable resource to customers by providing a low cost, incremental, short-term commitment alternative to either building additional generation resources or entering into long-term capacity agreements with other market participants. Short-term capacity purchases that either bridge gaps or delay longer term future generation investments should be a full and equal part of the planning calculus.

Q. PLEASE DESCRIBE THE BASIS FOR DUKE ENERGY KENTUCKY TO INCLUDE ANY CAPACITY PURCHASES TO OR FROM QUALIFIED FACILITIES UNDER PURPA THROUGH THE PSM.

A. I am aware that Duke Energy Kentucky currently has two tariffed rates for customers that have co-generation facilities including qualified facilities (QFs) as defined by Kentucky Administrative Regulation KAR 807 KAR 5:054 Section 1 and in accordance with PURPA, that set forth the terms and conditions where the Company would purchase energy from those customer-owned facilities. Duke Energy Kentucky witness Mr. Bruce Sailers supports these two tariffs in his testimony.

To date, the Company has had no customers taking service under either of these rates. In recent months, the Company has seen increased customer interest in making co-generation/QF investments. As such, the Company needs to ensure that if any such purchases are made the costs are recovered, such purchases could be used to either satisfy native load obligations, including as part of the Company's FRR Plan in the future, or to offset other Company-owned generation used to serve native load, which could potentially make such generation capacity available for off-system sales. Accordingly, the Company believes it is appropriate for any capacity-related purchases under the two co-generation tariffs be netted against the PSM. Energy purchases from co-generation will flow through the Company's FAC as a purchased power expense. However, capacity costs are not generally recoverable through the FAC. There is a direct nexus between the amount of non-native sales that are possible and any QF purchases that are made that "free" any Company-owned generation not otherwise dedicated to serve customers directly. Since customers share in the net revenues of such off-system sales, it stands to reason that the costs incurred should be netted against any such sales thereby enabled under the PSM.

Q. DO THE PROPOSED CHANGES TO RIDER PSM INCLUDE THE PERFORMANCE BONUSES AND NON-PERFORMANCE ASSESSMENTS ASSOCIATED WITH PJM'S CAPACITY PERFORMANCE STANDARDS?

A. Yes. To the extent Duke Energy Kentucky receives any performance incentives/bonuses from the PJM Capacity Performance market, the Company would share those through the PSM. Similarly, to the extent the Company receives any Capacity Performance non-performance assessments, those too would flow through the PSM.

The non-performance assessments and performance bonuses are two sides of the same Capacity Performance coin. A resource with actual performance above its committed or expected performance is considered to have provided bonus performance; and will be assigned a share of the collected non-performance charge revenues (collected from non-performing units) based on the ratio of its bonus performance quantity to the total bonus performance quantity from all resources for the same performance assessment hour.

Q. WILL DUKE ENERGY KENTUCKY UNITS BE ELIGIBLE FOR BONUS PAYMENTS?

A. Yes. An FRR entity like Duke Energy Kentucky will be eligible for bonus payments beginning in June 2019, when it becomes subject to Capacity Performance requirements.

Q. DO YOU EXPECT THAT DUKE ENERGY KENTUCKY PLANTS WILL HAVE AN OPPORTUNITY TO RECEIVE BONUS PAYMENTS?

A. Yes. Duke Energy Kentucky resources will likely be available for dispatch during a performance event. The extent of that likelihood can generally be described by the historical forced outage rate of any particular generator. As example, assuming an equal distribution of event hours across the year, a resource with a 10 percent historical forced outage rate can be expected to be available during 9 out of 10 event hours, and unavailable 1 out of 10 events. Since that forced outage rate is also utilized by PJM to determine the megawatt amount that PJM credits Duke Energy Kentucky for in the capacity market, it can also be used to determine the likely megawatts of generation available for bonus. If a fully committed 77 MW

Woodsdale unit had a 10 percent forced outage rate, 69 megawatts would be committed to PJM and 8 megawatts would likely be available to receive a performance bonus.

Additionally, since the Woodsdale capacity ratings are measured during summer temperatures to meet summer peak loads, Duke Energy Kentucky can expect additional megawatts available for bonuses during winter months during which ambient temperatures produce conditions that allow outputs well in excess of 77 megawatts, nearing 100 megawatts. These additional megawatts would all be eligible for bonus. While Duke Energy Kentucky cannot be certain whether units will perform better or worse than their historical average, and it cannot predict whether or not performance hours will fall in an equal distribution across the forced outage distribution, the Company's expectation is that, assuming Woodsdale is able to meet the fuel certainty requirements under Capacity Performance, the opportunity and likelihood for bonuses will exceed the potential for non-performance penalties.

Q. HOW WILL CAPACITY PERFORMANCE COMPLIANCE AND ANY POTENTIAL ASSESSMENTS AND BONUS PAYMENTS IMPACT CUSTOMERS?

A. Duke Energy Kentucky's generating assets are used and dedicated to serving its Kentucky load requirements. Our customers enjoy the benefit of having some of the lowest rates in the Commonwealth, not to mention as compared to those across the country. Our costs of operation are reflected in the rates we charge. At this juncture, Duke Energy Kentucky is focusing on making reasonable and prudent investments to "harden" its assets to reduce the risk of forced outages and in bringing Woodsdale into compliance in the least cost, most effective manner. Duke Energy Kentucky's customers are not yet exposed to any Capacity Performance bonus payments or non-compliance assessments. Nor will they be for at least the next two years. The goal of the Company's PSM proposal is to define a mechanism that shares risks and opportunities fairly, and maintains the alignment of interests between Duke Energy Kentucky and the customers it serves.

Q. IS THE COMPANY EXPLORING ANY ADDITIONAL PJM CAPACITY PERFORMANCE RISK MITIGATION STRATEGIES?

A. While outside of the scope of this rate case, Duke Energy Kentucky is evaluating alternative insurance products as secondary risk mitigation. It is worth restating that insurance alone does not obviate the significant risk of Woodsdale not being accepted as a Capacity Performance compliant resource by PJM. It would act merely as a potential hedge against a non-performance assessment if an event occurs and one of the Company's assets fails to perform.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING TO ADJUST THE RIDER PSM SHARING PERCENTAGES?

A. Duke Energy Kentucky witness William Don Wathen Jr., explains and supports the Company's proposed changes to the PSM in his testimony. In short the Company is proposing to simplify the calculation to eliminate the initial $1 million threshold, and adjust the sharing percentages to provide customers with 90 percent of all net revenues/costs and the Company retaining 10 percent. The reason for changing the sharing percentage is threefold. First, the change streamlines the calculation of all elements to the PSM in a fair and transparent manner. The second reason is to align the revenues and costs of ownership and dedication of the Company's generating assets to customers. Finally, moving the sharing calculation to a pure percentage-based sharing model ensures symmetry between the costs and benefits of participation in the wholesale markets.

V. INFORMATION SPONSORED BY WITNESS

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

A. FR 16(7)(h)(7) provides Duke Energy Kentucky's generation mix, which for the test year is projected to be approximately 99 percent coal and 1 percent gas/oil.

Q. DID YOU PROVIDE ANY INFORMATION TO MR. PRATT FOR HIS USE IN DEVELOPING THE FORECASTED FINANCIAL DATA?

A. Yes. I supplied Mr. Pratt with the following information for the forecasted portion of the base period, consisting of the six months ending November 30, 2017, and for the forecasted test period, consisting of the twelve months ending March 31, 2019.

I provided Mr. Pratt with certain production costs and revenues such as fuel costs, emission allowances costs and purchased power costs, and revenue derived from off-system sales, after applying the off-system sales sharing mechanism.

I also provided Mr. Pratt with the projected account balances, for his use in preparing the balance sheet, as of December 31, 2017, and for the forecasted test period for the following items: emission allowances, coal, oil, gas and materials and supplies. I obtained this information from historic trends and adjustments for expected changes forecasted within the GenTrader® Model run.

VI. CONCLUSION

Q. WAS FR 16(7)(h)(7), THE INFORMATION SUPPLIED TO MR. PRATT 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, John A. Verderame Managing Director, Power Trading and Dispatch, 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.

John A. Verderame Affiant

Subscribed and sworn to before me by John A. Verderame on this 27 day of July, 2017.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

Katie Jamieson
NOTARY PUBLIC

My Commission Expires: June 14, 2021

Direct Testimony of
William Don Wathen, Jr.

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

WILLIAM DON WATHEN JR.

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

September 1, 2017

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Don Wathen Jr., 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 of Rates and Regulatory Strategy for Ohio and Kentucky. 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 received Bachelor Degrees in Business and Chemical Engineering, and a Master of Business Administration Degree, all from the University of Kentucky. After completing graduate studies, I was employed by Kentucky Utilities Company as a planning analyst. In 1989, I began employment with the Indiana Utility Regulatory Commission as a senior engineer. From 1992 until mid-1998, I was employed by SVBK Consulting Group, where I held several positions as a consultant, focusing principally on utility rate matters. I was hired by Duke Energy (then Cinergy Services, Inc.), in 1998, as an Economic and Financial Specialist in the Budgets and Forecasts Department. In 1999, I was promoted to the position of Manager, Financial Forecasts. In August 2003, I was named to the position of Director - Rates. On December 1, 2009, I took the position of General Manager and Vice President of

Rates, Ohio and Kentucky. On July 3, 2012, as a result of the merger between Duke Energy and Progress Energy Corp., my title changed to Director of Rates and Regulatory Strategy for Ohio and Kentucky.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF RATES AND REGULATORY STRATEGY FOR OHIO AND KENTUCKY.

A. As Director of Rates and Regulatory Strategy for Ohio and Kentucky, I am responsible for all state and federal rate matters involving Duke Energy Kentucky and its parent, Duke Energy Ohio, Inc.

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

A. Yes. I have previously testified in a number of cases before the Kentucky Public Service Commission (Commission) and other regulatory commissions.

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

A. On behalf of Duke Energy Kentucky, I provide some background for its request to increase base electric revenues and the drivers behind the Company's application. I also support other requests including: (1) proposed changes to the riders for fuel cost recovery and profit sharing of off-system sales; (2) creation of a new rider to address gaps in recovery of unavoidable transmission costs incurred by Duke Energy Kentucky from its participation in PJM Interconnection, LLC. (PJM); (3) creation of a new rider to recover incremental capital costs associated with specific programs to modernize and improve the Company's electric distribution grid; and (4) implementation of an environmental surcharge mechanism (ESM) authorized under KRS 278.183. I will also provide testimony supporting the Company's proposals relating to amortizing existing accounting deferrals previously approved by the Commission and the need for additional deferrals. I then discuss the Company's compliance with a number of Commission directives from prior cases. I support the reasonableness of the Company's proposed rate increase and sponsor Filing Requirement (FR) 16(1)(b)(1) to comply with the Commission's filing requirements.

II. BACKGROUND AND DRIVERS FOR REQUESTED RATE INCREASE

Q. WHEN DID THE COMMISSION APPROVE DUKE ENERGY KENTUCKY'S CURRENT ELECTRIC DISTRIBUTION RATES?

A. The Company's current base rates for electric service were approved by the Commission on December 21, 2006, in Case No. 2006-00172 (2006 Rate Case). The test period in that proceeding was the twelve months ended December 31, 2007, and the rate base and capitalization used in that case was the thirteen-month average from December 31, 2006, through December 31, 2007. The current rates went into effect on January 2, 2007.

The last rate case was significant in that it was the first base rate case after Duke Energy Kentucky acquired its own generation to meet its own load obligations. In 2006, Duke Energy Kentucky acquired three generating stations from its parent Duke Energy Ohio. The acquisition of this generating capacity relieved Duke Energy Kentucky of being completely dependent on purchased power for meeting its load obligations.

Q. HAS THERE BEEN ANY CHANGE TO THE COMPANY'S GENERATION PORTFOLIO SINCE THE LAST RATE CASE?

A. Yes. There have been significant changes that impact the Company's generation portfolio since the Company's last electric rate case. At the time of the last rate case, Duke Energy Kentucky was a member of the Midcontinent Independent System Operator, Inc. (MISO). Effective January 1, 2012, and with Commission authorization, Duke Energy Kentucky, along with its parent company, Duke Energy Ohio, left MISO and became a member of PJM.[1] The move to PJM also brought Duke Energy Kentucky into a regional transmission organization (RTO) with more advanced capacity and energy markets.

Another significant event occurred on December 31, 2014. Duke Energy Kentucky rededicated its commitment to Kentucky-sited coal-burning resources by becoming the sole owner of the East Bend Generating Station (East Bend), purchasing the remaining 31 percent interest that was owned by The Dayton Power & Light Company (DP&L).[2] The Commission approved this transaction on December 4, 2014, in Case No. 2014-00201, which added approximately 186 MW of capacity (net installed) for only $12.4 million.

The need for that acquisition was attributable to the retirement of approximately 163 MW of capacity (net installed) at the Company's Miami Fort

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[1] *In the Matter of the Application of Duke Energy Kentucky, Inc., for Approval to Transfer Functional Control of its Transmission Assets from the Midwest Independent Transmission System Operator to the PJM Interconnection Regional Transmission Organization and Request for Expedited Treatment,* Case No 2010-00203, (Ky.P.S.C. Dec. 22, 2010).

[2] *In the Matter of the Application of Duke Energy Kentucky, Inc., for (1) A Certificate of Public Convenience and Necessity Authorizing the Acquisition of the Dayton Power & Light Company's 31% Interest in the East Bend Generating Station; (2) Approval of Duke Energy Kentucky, Inc.'s Assumption of Certain Liabilities in Connection with the Acquisition; (3) Deferral of Costs incurred as Part of the Acquisition; and (4) All Other Necessary Approvals, and Relief,* Case No 2014-00201 (Ky. P.S.C. Order, December 4, 2014.)

Unit 6 (MF6). MF6 was an unscrubbed unit whose retirement became necessary due to an inability to cost-effectively comply with the Mercury Air Toxics Standard (MATS). The acquisition of DP&L's share of East Bend came at an opportune time as it allowed Duke Energy Kentucky to replace the then soon to be retired capacity from MF6 with a resource that was well known to the Company and was determined to be the most economical solution possible at the time. MF6 was retired effective May 31, 2015.

Q. WHAT PERIOD IS DUKE ENERGY KENTUCKY USING FOR ITS FORECASTED TEST PERIOD?

A. The Company's Application in this case requests an increase in overall electric revenues based on a forecasted test period, namely, the twelve-month period beginning April 1, 2018, through March 31, 2019.

Q. WHY IS DUKE ENERGY KENTUCKY FILING A RATE CASE AT THIS TIME?

A. For the forecasted test period, the Company is projecting that the earned return on its investment in the electric system is not providing a fair and reasonable compensation to its investors.

Since the time of the last base rate case, the Company has made significant capital investments. Gross utility plant in the 2006 Rate Case was approximately $1.122 billion. The thirteen-month average of gross plant in this forecasted test period for this case is $1.731 billion, an increase of approximately $600 million in gross utility plant. The depreciation, property taxes, and return on this increased investment are the principal drivers of the need for new rates. Importantly, the

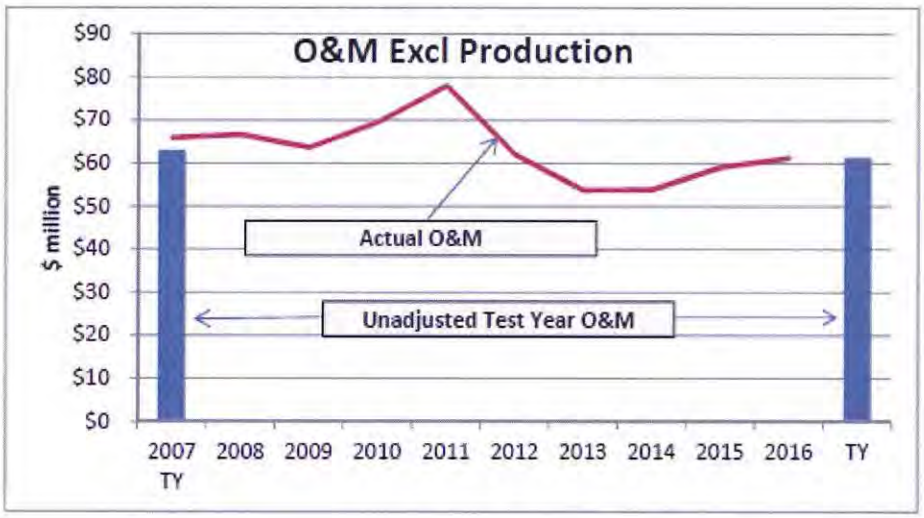
Company has diligently controlled its operation and maintenance (O&M) over that time and, except for an increase in non-fuel production O&M expenses associated with the acquisition of DP&L's share of East Bend, there has been very little change in non-fuel O&M since the time of the last rate case. Compared with the non-fuel O&M associated with the Company's share of MF6, the non-fuel O&M associated with the newly acquired share of East Bend is higher. The test year O&M in this case reflects this increase in O&M associated with owning all of East Bend.

This effort to control costs through efficiency and productivity gains has helped the Company avoid the need for an electric base rate increase for more than eleven years and customers have benefitted having among the lowest rates in the state and the country.

Another significant driver of the need for a rate case is to begin recovery of certain deferrals. The Commission has approved a number of deferrals for Duke Energy Kentucky, including storm costs, costs associated with the East Bend acquisition, and costs associated with environmental compliance. A component of Duke Energy Kentucky's projected revenue requirement includes amortization of these previously approved deferrals.

Q. PLEASE QUANTIFY THE COMPANY'S SUCCESS IN CONTROLLING ITS NON-PRODUCTION O&M EXPENSE SINCE ITS LAST BASE ELECTRIC RATE CASE.

A. The chart below best demonstrates the fact that the Company has successfully controlled its non-production O&M costs over the last ten years. The bars to the left and right represent the Company's test year non-production O&M expense in its 2006 Rate Case and that projected in this current case, respectfully. The horizontal line shows the Company's non-production O&M, as reported in its FERC Form 1 Annual Reports, for each of the last ten years. As this chart shows, the Company's non-production O&M expense has remained relatively flat for the last decade.



The Company's efforts at managing its costs have enabled it to maintain electric rates that are, on average, the lowest in the Commonwealth of Kentucky for most rate classes.

Q. HAS LOAD GROWTH OFFSET THE NEED FOR THE PROPOSED INCREASE?

A. Not very much. Since the time of the 2006 Rate Case, load growth has been stagnant. Although the Company has added customers, albeit at a very slow rate, overall sales have essentially been flat due to energy efficiency and customers being more sophisticated and mindful about controlling their energy consumption. Total retail sales for the test period in the last rate case were 4,021,971 MWh. For the forecasted test period in this proceeding, Duke Energy Kentucky is projecting total retail sales of 4,087,791 MWh, an increase of only 1.6 percent over the nearly eleven-year period (approximately 0.15 percent average annual growth). Inasmuch as the Company's customer charge is relatively low, particularly for residential customers, the growth in customer count has not been enough to offset the factors reducing customers' average usage.

Q. IS THE COST OF CAPITAL CONTRIBUTING TO OVERALL INCREASE?

A. No. Actually, since the time of the last rate case, the cost of capital has decreased. Although the last case was settled without specifying a return on equity, the return on equity of 10.3 percent being proposed in this case is significantly lower than the rate proposed in the 2006 Rate Case, which was 11.5 percent as filed. Additionally, the cost of debt has also decreased over that period. The Company's application in 2006-00172 included a long-term debt interest rate of 5.707 percent. The long-term debt interest rate for the forecasted test period in this case has fallen to 4.243 percent. The significance of the change in cost of capital is that, although the Company's investment has grown since the time of the last rate case, the cost of capital related to the investment has offset a significant portion of that cost of that investment.

Q. THE COMMISSION RECENTLY APPROVED THE COMPANY'S APPLICATION TO IMPLEMENT ADVANCED METERING IN ITS SERVICE TERRITORY. WILL YOU DESCRIBE HOW THAT PROGRAM IS BEING ADDRESSED IN THE RATE CASE?

A. On May 25, 2017, the Commission modified and approved a stipulation reached between the Company and the Attorney General, in Case No. 2016-00152, for a certificate of public convenience and necessity (CPCN) request to implement advanced metering infrastructure (AMI) deployment in its electric and gas service territories (AMI Case). The Commission's May approval of the Company's CPCN was later than what was anticipated in the Company's application in Case No 2016-00152. As a result, the Company's actual AMI deployment is significantly later than the plan submitted in the cost-benefit analysis submitted in that case.

The Company commenced installation of the new metering technology in August 2017 and expects to continue installations through most of 2018 when the deployment is expected to be complete.

As part of the stipulation in that proceeding, the Company agreed to provide customers with a level of projected savings. Company witness Ms. Sarah E. Lawler sponsors a pro forma adjustment to the forecasted test year revenue requirement to reflect an acceleration of the expected savings, above amounts already included in the forecasted test year, from the advanced metering initiative. This adjustment provides customers with the benefit of the anticipated level of savings immediately upon the effective date of the new rates proposed in this case, which should be several months prior to when the Company completes the AMI deployment, and also before the actual savings through reductions in meter reading expense and other O&M are fully achieved, as shown in the Company's cost benefit analysis submitted in the AMI Case.

Q. THE COMMISSION ALSO RECENTLY APPROVED THE COMPANY'S APPLICATION FOR A CPCN RELATED TO ITS ASH POND AT EAST BEND. HOW IS THE COMPANY PROPOSING TO RECOVER THE COSTS RELATED TO THIS PROGRAM?

A. As part of its application in this proceeding, Duke Energy Kentucky is seeking to implement, for the first time, an environmental surcharge mechanism (Rider ESM). I will provide additional details on this proposal but, as it relates to the ash pond at East Bend, the Company is proposing to recover these costs via the new Rider ESM as described in the testimony of Ms. Lawler.

III. <u>ADDITIONAL RELIEF REQUESTED</u>

A. <u>Fuel Adjustment Clause and Profit Sharing Mechanism</u>

Q. WHAT IS DUKE ENERGY KENTUCKY PROPOSING WITH RESPECT TO ITS FUEL ADJUSTMENT CLAUSE?

A. Duke Energy Kentucky is seeking to update its Fuel Adjustment Clause (FAC) to incorporate all of the appropriate PJM billing line items (BLIs) associated with fuel and purchased power-related charges and credits for serving its Kentucky customers. As a member of PJM, all of Duke Energy Kentucky's generation is sold in PJM's wholesale markets. At the same time, Duke Energy Kentucky purchases all of its load requirements from PJM's wholesale markets. This is true for all of the Kentucky utilities that own generation and serve load as members of PJM.

For determining how much fuel and purchased power costs should be assigned to Duke Energy Kentucky's retail customers, the Company uses a well vetted, after-the-fact dispatch methodology to assign the lowest cost generation and lowest cost purchased power to retail load. PJM provides monthly invoices to Duke Energy Kentucky with a number of BLIs that provide a summary of the charges and credits associated with its use of the PJM transmission system and its participation in the wholesale capacity, energy, and ancillary markets. Duke Energy Kentucky witness, Mr. John D. Swez, provides an explanation of all of the BLIs that the Company receives from its membership in PJM and how these BLIs impact Duke Energy Kentucky.

Duke Energy Kentucky's FAC was implemented in 2007 when the Company was a member of MISO. Therefore, the Company's initial FAC included the categories of fuel and purchased power based on MISO's billing format. Around 2009, MISO expanded its role by implementing a market for ancillary services that were not included in base rates or any rider as part of the 2006 Rate Case. As I discuss below, the Company has provided customers with the benefit of incremental revenue received from the ancillary services market since its inception.

In 2011, the Commission approved Duke Energy Kentucky's request to exit from MISO and to join PJM beginning January 1, 2012. Thus, when the Company joined PJM in 2012, the Company began receiving invoices from PJM with different BLIs that substantially mirrored the MISO BLIs that had been included in the FAC. Importantly, the BLIs appearing on PJM's invoices are similar to those on MISO's invoice but they are not identical. For example, PJM's BLIs separate the charges and credits for fuel and purchased power in a manner that is different than the form supplied by MISO.

In an effort to establish some consistency and uniformity for all of the Kentucky jurisdictional utilities in PJM, Duke Energy Kentucky, Kentucky Power Company, and East Kentucky Power, collaborated to examine all of the PJM BLIs to identify a consistent list of BLIs that are appropriate for FAC recovery. Because this case represents the first base electric rate case since the Company first joined PJM, the Company has examined all of the PJM BLIs and has identified all of those costs and credits that are affected by and attributable to serving the Company's native load by way of fuel and purchased power. The Company is proposing changes to ensure that the Company is recovering all of its costs (and flowing through all credits) related to fuel and purchased power that are incurred to serve its Kentucky retail customers. Mr. Swez's testimony discusses the Company's proposed changes.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S PROFIT SHARING MECHANISM (RIDER PSM).

A. The Company's Rider PSM provides a means to flow through to customers most of the profits (or margins) it derives from owning and operating its generation. Beginning in January 2007, Duke Energy Kentucky's customers began paying rates that included the cost of generation owned by Duke Energy Kentucky. The rational *quid pro quo* for this arrangement is that customers should benefit from any opportunity the Company has to derive value from this generation. The sharing mechanism in Rider PSM gives customers most of the value of this generation while giving the Company a small share as an incentive to maximize this value – a "win/win" proposition from a regulatory point of view.

Rider PSM evolved over time as the Company found new opportunities to derive value from its generation resources but, generally, the existing Rider PSM includes the following provisions:

- Off-system sales: as approved in Case No. 2006-00172, the first $1 million in annual margins from off-system sales flow to customers. Margins above $1 million are shared 75 percent to customers and 25 percent to the Company.[3]
- Emission allowances (EAs): as approved in Case No. 2006-00172, 100 percent of the net gains on the sale of EAs flow through to customers.
- Ancillary services markets (ASM): Approved in Case No. 2008-00489, the Company requested, and the Commission authorized the Company to amend its PSM to include net revenues from MISO's newly implemented ASM. The net monthly ASM margins were combined with the off-system sales margins and the first $1 million in annual margins flow to customers. Margins above $1 million are shared 75 percent to customers and 25 percent to the Company.
- Capacity Purchases/Sales: Approved in Case No. 2014-00201. The Company shares the net of (1) revenue acquired from DP&L sale of its share of East Bend into PJM's capacity markets, less (2) the cost

[3] As originally approved, the off-system sales sharing percentages were originally equally shared, 50/50 between customers and the Company. In Case No. 2010-00203, the Commission, as a condition to approving the Company's realignment from MISO to PJM, directed the sharing percentages be adjusted to the current 75/25 ratio.

of purchasing capacity to meet its obligations under PJM's reliability assurance agreement due to the retirement of MF6.

Q. WHAT CHANGES IS DUKE ENERGY KENTUCKY PROPOSING FOR ITS RIDER PSM?

A. The Company is proposing several changes to its Rider PSM to expand the categories of revenues (net of costs) available for inclusion in Rider PSM and to streamline the administration and calculation of Rider PSM. First, consistent with the changes to the FAC, the Company is proposing to make similar adjustments to its Rider PSM to reflect PJM BLIs that are related to credits and charges attributable to the off-system sales shared with customers under the Rider PSM.

Second, the Company is proposing to adjust the categories of eligible net proceeds (credits and charges) that can be flowed through the PSM to include reconciliation of all types of revenues (positive or negative) derived from the Company's ownership and dedication of generating assets to Kentucky customers. Rider PSM will be expanded to include all wholesale energy, capacity, and ancillary services markets (net costs and credits) that are now available or may become available in PJM. This will include net costs and revenues that are derived from the PJM's newly implemented capacity performance market requirements and for short-term (less than one year in duration) capacity purchases necessary to meet the Company's three-year fixed resource requirement (FRR) plan (and any gains/losses on the sale of this capacity). The Company is also proposing to include costs of any capacity payments made to co-generation facilities, including qualifying facilities, under the terms of one of Duke Energy

Kentucky's cogeneration tariffs. The Company is also proposing to include any net proceeds from the sale of renewable energy certificate (RECs) derived from any Company-owned renewable generating resources, including the recently announced 7 MW solar facility scheduled to be completed in late-2017, as well as for any renewable resources that Duke Energy Kentucky may own in the future to the extent that the revenue requirement for such renewable resources are being recovered in base rates.[4]

The current Rider PSM includes a provision for gains on the sale of EAs. As noted above, the Company is proposing to implement an environmental surcharge mechanism and will begin addressing cost recovery and the sharing of any gains/losses on the sale of EAs in the proposed Rider ESM.

Another significant change being proposed is to modify the sharing percentage between customer and shareholders. The Company is proposing to simplify the sharing by modifying the 75/25 split described above such that customers will begin receiving 90 percent of the amounts flowing through Rider PSM and to eliminate the $1 million threshold in the sharing formula. Rather than have a two-stage sharing mechanism for 'some' of the Rider PSM components, applying the 90/10 sharing formula to all components for all amounts will streamline the process.

Q. WILL CHANGING THE $1 MILLION THRESHOLD AND SHARING PERCENTAGES HARM CUSTOMERS?

A. No. Since the establishment of Rider PSM, the Company has consistently had off-

[4] *In the Matter of the Application of Duke Energy Kentucky, Inc., for an Order Declaring the Construction of Solar Facilities is an Ordinary Extension of Existing Systems in the Usual Course of Business* Case No. 2017-00155 (Ky. P.S.C. July 10, 2017).

system sales that exceeded $1 million. Nonetheless, the Company's proposal to increase the sharing percentages should not result in any negative impact to customers with the elimination of this threshold. Also, the elimination of the threshold will make the calculation simpler and will reduce the time and expense in monitoring the Rider PSM calculation and having to restate sales in relation to the threshold on a quarterly basis.

Q. DOES INCLUDING THE PJM CAPACITY PERFORMANCE COMPLIANCE INCENTIVES AND NON-PERFORMANCE ASSESSMENTS UNFAIRLY PUT CUSTOMERS AT RISK FOR COSTS?

A. No. As explained by Duke Energy Kentucky witness John Verderame, the Company is taking prudent and necessary steps to fortify or harden its assets so that the risk of capacity performance costs is minimized and the possibility of performance incentives is maximized. These steps include proactively maintaining the facilities and ensuring certainty of fuel supplies for the Company's two generating stations. While the Company's efforts will minimize the potential for incurring non-performance assessments, it is not a reasonable expectation that such risks can be completely eliminated. The Company's proposal retains a share in the benefits and risks of non-performance through its ten percent share of Rider PSM net revenues. The revenues from the ownership and dedication of the Company's generating assets necessarily include all revenue opportunities in PJM. Fairness dictates sharing of any costs that are or could be incurred by participation in these markets. The Capacity Performance incentives and non-performance assessments are allocated to Duke Energy Kentucky through FERC-approved tariffs. Compliance with PJM's Capacity Performance rules is necessary for the Company and its customers to continue enjoying the benefits of membership in PJM. Therefore, modifying Rider PSM to allow a sharing of both the benefits and the costs of membership in PJM is reasonable and fair, particularly when the Company is proposing to change the model so as to provide customers with an even greater share of net revenues – a greater proportion, I might add, than what the other investor-owned electric utilities share through their similar riders.

Q. IS THE COMPANY PROPOSING ANY OTHER CHANGES TO RIDER PSM?

A. Yes. As I alluded to earlier, there are different categories of costs/benefits that flow through Rider PSM. The methodologies for netting costs and benefits also vary depending on the category of costs. Going forward, Duke Energy Kentucky proposes to adjust the netting mechanism so that netting occurs over the course of the calendar year. In other words, whether the PSM is a charge or a credit in a particular year will be based on the sum of all of the PSM credits in the year at issue compared to all of the PSM charges for the same year, plus any true-up of over- or under-recovery in the prior year.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO THE PROCESS FOR FILING RIDER PSM?

A. Except for the change in the netting methodology, Rider PSM will operate essentially the same as it does today. The Company will make quarterly adjustments to Rider PSM, just as it does now, to reflect updated charges and credits. Although there will likely be some final reconciliations to transition from the existing Rider PSM formula to the proposed Rider PSM formula, the transition will be seamless to customers.

Q. HAS THE COMPANY INCLUDED A TEMPLATE FOR ITS REVISED RIDER PSM IN THIS CASE?

A. Yes. Ms. Lawler includes a template for the revised Rider PSM as an attachment to her testimony.

B. FERC Transmission Cost Reconciliation Rider

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO CREATE A NEW FERC TRANSMISSION COST RECONCILIATION RIDER (RIDER FTR).

A. Duke Energy Kentucky is proposing to implement a new rider, Rider FTR, which is intended to recover or credit specific, and ever changing, PJM transmission costs. The specific costs include network integration transmission service (NITS), both firm and non-firm point-to-point, market administrations fees and potentially other transmission costs that may be billed in the future related to serving retail load that is above or below the level included in the Company's base rates established in this proceeding. Also, the Company is proposing that the rider also track incremental changes in costs associated with PJM's Regional Transmission Expansion Plan (RTEP) costs that are incremental, higher or lower, to what the Company is proposing to include in its base rates.

Q. HOW WILL THIS MECHANISM WORK?

A. Duke Energy Kentucky is charged for NITS and RTEP via invoices from PJM at rates authorized by FERC under PJM's Open Access Transmission Tariff. The magnitude of NITS, RTEP, and many other charges are largely outside of Duke Energy Kentucky's control. The Company's proposal is to implement a new rider that will track such PJM credits and charges invoiced to Duke Energy Kentucky. On a quarterly basis, the Company will adjust Rider FTR based on the most recent actual monthly invoices received from PJM. The Company submits to an annual review of its Rider FTR for Commission of the invoiced costs and the revenue collected under the rider.

The Company will file the rider 30 days before it is scheduled to go into effect, along with supporting details to justify the amount to be collected via the rider and any other information as may be required by the Commission.

Attachment WDW-1 provides an illustration of the quarterly filing. Duke Energy Kentucky witness Sailers supports the proposed new Rider FTR tariff in his testimony.

Q. WILL YOU PROVIDE SOME ADDITIONAL BACKGROUND ON THE PJM COSTS THAT WOULD BE INCLUDED IN THIS RIDER?

A. The most significant charge billed to Duke Energy Kentucky is for NITS. Duke Energy Kentucky has very little transmission investment of its own and primarily relies on the transmission system owned by Duke Energy Ohio and in addition to the overall PJM grid to transmit power to retail customers across its delivery system. As a result, transmission is a significant expense that Duke Energy Kentucky incurs to serve its Kentucky load and has little to no control over such costs. The NITS rates applicable to Duke Energy Kentucky are set each year, under a FERC-approved formula rate, and establish a price based on peak demand applicable to transmission customers on the Duke Energy Ohio and Duke Energy Kentucky (DEOK) transmission system. Duke Energy Kentucky is considered one of those transmission customers for the transmission system. Each month Duke Energy Kentucky is invoiced for its use of the transmission system based on its annual peak demand.

Again, the NITS charges billed to Duke Energy Kentucky are essentially outside the control of the Company, but it is worth noting that the actual rates for NITS service in the DEOK zone are among the lowest of all the NITS rates for transmission owners in PJM, as published on its website.[5]

Another charge to be included in Rider FTR is RTEP. RTEP is PJM's process for identifying transmission system additions and improvements that it deems necessary to keep electricity flowing to the millions of customers throughout PJM's region. All network customers and merchant transmission owners in PJM pay owners of transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12 of PJM's tariffs. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates.[6] All network customers serving load in a geographic zone pay for that zone's applicable projects' revenue requirements in proportion to their network service peak load share in that zone, and responsible merchant transmission owners also pay their share of applicable revenue requirements. Approval of these projects and the incurrence of costs for

[5] http://www.pjm.com/markets-and-operations/billing-settlements-and-credit.aspx. Last visited August, 6, 2017.
[6] Ibid.

these projects are also outside of Duke Energy Kentucky's control.

Q. WHAT IS THE LEVEL OF TRANSMISSION EXPANSION PLAN COSTS CURRENTLY REFLECTED IN THE COMPANY'S BASE RATES?

A. Presently, there are no costs related to transmission expansion planning being recovered in the Company's base rates. As I previously mentioned, Duke Energy Kentucky was a member of MISO at the time of its last base rate case and, at the time of the last base rate case, MISO was not charging Duke Energy Kentucky for any regional transmission expansion plan costs. In fact, MISO did not implement its tariff for MISO Transmission Expansion Plan (MTEP) until 2008, after the test year used in the Company's last base rate case. Consequently, Duke Energy Kentucky is not recovering any MTEP costs in base rates. Additionally, no MTEP costs have been included in any rider currently approved for Duke Energy Kentucky.

Duke Energy Kentucky began incurring RTEP costs when it moved from MISO to PJM beginning January 2012. Here again, the incurrence of these costs began well after the last base rate case. Therefore, the Company has not recovered any of the FERC-approved RTEP costs or FERC-approved MTEP costs incurred to date.

Q. IS COST RECOVERY OF RTEP REASONABLE?

A. Yes. These RTEP investments are necessary to improve the overall transmission grid, upon which Duke Energy Kentucky relies upon and its customers benefit from, for the ready access to low-cost energy. The RTEP transmission projects are vetted through a PJM process to determine improvements needed to cost-effectively serve the customers in its footprint. Costs are allocated to PJM members, at least in part, based upon their proportional share of usage based upon load in the PJM system. As a result, the projects, and costs that are allocable to Duke Energy Kentucky are indeed for the beneficial use of its customers.

Q. IS DUKE ENERGY KENTUCKY STILL INCURRING MTEP CHARGES?

A. Yes.

Q. IS DUKE ENERGY KENTUCKY SEEKING RECOVERY OF MTEP COSTS IN THIS FILING?

A. No. As I discuss below, Duke Energy Kentucky made a commitment in Case No. 2010-00203 that it would not seek to recover both RTEP and MTEP. The Company, therefore, is only seeking recovery of RTEP charges in this proceeding. Furthermore, the Company is only seeking recovery of RTEP charges beginning with charges incurred for periods beginning April 1, 2018, *i.e.*, the first day of the forecasted test period in this case. There was no deferral mechanism created for the Company to recover transmission expansion costs for prior years. As a result, customers have not been paying and will not pay for RTEP costs incurred through March 31, 2018 (assuming the Commission approves new rates as part of this case to be effective April 1, 2018).

Q. WILL YOU PROVIDE SOME ADDITIONAL BACKGROUND ON THE COMMITMENT RELATED TO MTEP AND RTEP?

A. Yes. When Duke Energy Kentucky received the Commission's approval to move from MISO to PJM, it was subject to several conditions. Relevant to the issue of transmission expansion costs from either MISO or PJM, the Commission held:

> "Duke [Energy] Kentucky should not seek to double-recover in a future rate case the transmission expansion fees that it may be charged by the [MISO] and PJM in the same period or overlapping periods, nor should it seek to defer and/or amortize any transmission expansion fees it incurs for [MISO] transmission expansion projects which received approval when it was a member of the [MISO], regardless of whether or not such fees are approved by FERC."

Duke Energy Kentucky agreed to this condition by letter filed with the Commission dated December 28, 2010.

Q. IS DUKE ENERGY KENTUCKY'S PROPOSAL IN THIS PROCEEDING CONSISTENT WITH THAT CONDITION AND COMMITMENT?

A. Yes. The Company continues to receive charges from MISO related to the MTEP projects that were approved during the time the Company was a MISO member and before it left for PJM. Such is the case under MISO's FERC-approved tariffs. As I previously stated, there are no MTEP costs reflected in the Company's current base rates because such costs did not exist at the time of the Company's last electric rate case. And the Company is not proposing to include any MISO-related costs for recovery in its base rates or in any rider request in this proceeding even though it continues to receive such allocations from MISO.

In this proceeding, Duke Energy Kentucky is only seeking to recover the costs of PJM's RTEP by including the amount in base rates and implementing Rider FTR to track changes, along with the requisite deferral accounting for over-and under-recovery, from the base rate amount (similar to the model for tracking fuel costs under 807 KAR 5:056).

Q. GIVEN THE COMMITMENT IN CASE NO. 2010-00203 NOT TO SEEK BOTH RTEP AND MTEP, WHY SEEK RECOVERY OF RTEP INSTEAD OF MTEP?

A. Duke Energy Kentucky is currently a PJM member and its customers benefit from the use of PJM's expansive transmission system with access to the largest wholesale capacity and energy market in the United States, and also benefit from its use of PJM's transmission system for delivery of electricity throughout the Company's service territory. It is reasonable that the Company be able to include such costs incurred to actually serve its retail load in its retail rates. Because only PJM-transmission costs are included in the Company's test year revenue requirement and are being proposed for inclusion in the Rider FTR, the Company is complying with the Commission's prior directive.

On the other hand, Duke Energy Kentucky is not currently a member of MISO and does not use its transmission system, participate in its capacity and energy markets, or participate in its ancillary services market. That the Company is being charged MTEP at all is only the result of terminating a contractual arrangement. Customers receive no value from MTEP charges; therefore, Duke Energy Kentucky will not be seeking recovery of MTEP charges from MISO and will continue to hold its customers harmless for those charges.

Q. IS THE COMPANY PROPOSING TO FLOW THROUGH ALL TRANSMISSION RELATED PJM CREDITS AND CHARGES TO ITS RETAIL CUSTOMERS?

A. No. The Company is only proposing to track and adjust for the FERC-jurisdictional transmission expenses that Duke Energy Kentucky actually incurs through PJM credits and charges BLIs. There will likely be adjustments to invoices from prior periods that will not be included in the proposed rider. Such adjustments to credits and charges for periods prior to the effective date of new rates resulting from this case will not flow through the new rider. RTEP charges, for example, are not currently being recovered from customers; therefore, any adjustments to prior period charges for RTEP, which have not yet been recovered from customers, will be excluded from the rider. For those types of credits and charges, adjustments to prior periods will only be applicable for periods beginning with the effective date of the new rates. Mr. Swez discusses the Company's proposal for assigning cost recovery of all PJM billing line items, including those that would be appropriate for recovery through the Rider FTR in his direct testimony and accompanying attachments.

C. Distribution Reliability and Integrity Performance Improvement Plan

Q. IS DUKE ENERGY KENTUCKY PROPOSING ANY NEW COST RECOVERY MECHANISM RELATED TO ITS DISTRIBUTION SYSTEM INTEGRITY AND RELIABILITY IMPROVEMENT PERFOMANCE PLAN?

A. Yes. Duke Energy Kentucky is proposing to implement a discrete cost recovery mechanism for specific, Commission-approved projects undertaken by the Company outside of its base rate case that are designed to provide customer benefits through system integrity or reliability performance improvements related to the Company's distribution system. Duke Energy Kentucky witness Mr. Anthony Platz provides an overview of the specific program being proposed for Rider DCI by the Company in this case including a projection of the capital spending expected.

The purpose of this new recovery mechanism is to provide a mechanism for the Company to accelerate deployment of programs to improve its electric delivery system integrity or reliability as well as a means for the Company to more timely recover its capital invested for these projects, thereby reducing regulatory lag that would otherwise occur through pure base rate recovery of these types of program costs and that must compete with other projects funded through the Company's base rates. Minimizing regulatory lag also allows the Company and all stakeholders to avoid the expense of multiple rate cases.

The idea behind this mechanism is similar to that of the Company's accelerated service line replacement program (ASRP) for natural gas whereby the Company is able to address reliability and integrity concerns with its delivery system to provide greater levels of service to the Company's customers.

Admittedly, Duke Energy Kentucky has not had frequent rate cases, *i.e.*, this Application represents the first in over eleven years. However, the Company is expecting to significantly ramp up its efforts to modernize the distribution system, following the lead of its regional affiliates, Duke Energy Ohio and Duke

Energy Indiana. The Company's proposal will facilitate its ability to be proactive rather than reactive in investing in such projects while mitigating the negative impacts on its earnings between rate cases.

Q. HOW WILL THIS MECHANISM WORK?

A. Duke Energy Kentucky is proposing a distribution capital investment rider (Rider DCI) that will operate much like the Rider ASRP that was recently approved by this Commission for the Company's gas business. Ms. Lawler includes a template for the Rider DCI filings. Once approved, the Company will make annual applications to establish new rider rates based on the actual incremental investment in eligible plant in service (*i.e.*, incremental rate base) as of the end of each calendar year. The revenue requirement for the rider will include a return on the incremental rate base (*i.e.*, gross plant less accumulated depreciation less accumulated deferred income taxes), income taxes on the equity component of the return, property taxes, and depreciation expense associated with the incremental investment. The rider will only include incremental revenue requirement associated with the capital investment and will not include recovery of incremental O&M expenses. The Company is proposing to allocate the resulting revenue requirement based on the allocation factors used for underground distribution equipment from its cost of service study. The resulting revenue requirement allocated to each class would then be charged to customers on a per bill basis. Mr. Sailers supports the Company's proposed new tariff rate, Rider DCI in his direct testimony.

As part of the annual application to be reviewed by the Commission, the

Company may propose new programs for inclusion in the rider, *i.e.*, programs that are incremental to what was included in base rates. The rate of return established for the rider will be the overall pre-tax rate of return, approved by the Commission in this current case. The revenue requirement for the rider will be rolled into base rates when new base rates are established as a result of a base rate case filing; however, the Company commits that if it has not had another electric base rate proceeding within three years of the implementation of the rider, that it will submit testimony supporting the continuation of the approved rate of return or propose a new rate of return for the Commission to consider for the rider.

Q. ARE YOU AWARE OF ANY OTHER REGULATORY COMMISSIONS APPROVING THE ESTABLISHMENT OF SUCH A DISTRIBUTION CAPTIAL RECOVERY MECHANISM FOR ELECTRIC UTILITIES?

A. Yes. I am personally aware that every investor-owned electric utility in Ohio has an incremental distribution capital recovery rider supported by and approved by the Public Utilities Commission of Ohio.[7] Additionally, the Indiana Utility Regulatory Commission has approved transmission, distribution, and natural gas capital recovery mechanisms for Duke Energy Indiana, Inc., NIPSCO, and

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[7] *See e.g. In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case No. 10-388-EL-SSO, Opinion and Order, at pp. 11-12, 46 (August 25, 2010)(approval of Delivery Capital Recovery Rider); *In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case No. 12-1230-EL-SSO, Opinion and Order, at pp. 10-11, 57 (July 18, 2012)(approval to continue the Delivery Capital Recovery Rider); *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan,* Case No. 11-346-EL-SSO, *et al.*, Opinion and Order, at pp. 46-47 (August 8, 2012)(approval of Distribution Investment Rider).

Vectren.[8] The use of capital recovery mechanisms is not novel or groundbreaking. In fact, these mechanisms are used routinely in the industry for programs that provide both benefits to customers and allow the utilities to timely recover costs to provide service to customers.

I have attached a document, Confidential Attachment WDW-2, produced by Regulatory Research Associates (RRA) that summarizes cost recovery mechanisms for utilities across the country. Confidential Attachment WDW-2 is being filed under seal with the protection of a Petition for Confidential Treatment. As can be observed in that document, many regulators across the country have existing riders that allow their respective regulated utilities to timely recover capital investments.

D. <u>Environmental Surcharge Mechanism</u>

Q. PLEASE EXPLAIN DUKE ENERGY KENTUCKY'S PROPOSAL TO IMPLEMENT AN ENVIRONMENTAL SURCHARGE MECHANISM.

A. Duke Energy Kentucky is proposing to implement Rider ESM, authorized under KRS 278.183, as part of this case. Duke Energy Kentucky witnesses Joseph A. Miller and Tammy Jett further explain the Company's proposal and the projects to be included in its initial compliance plan in greater detail.

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[8] *In Re: Verified Petition of Duke Energy Indiana, Inc. for: (1) Approval of Petitioner's 7-Year Plan for Eligible Transmission Distribution and Storage System Improvements, Pursuant to Ind. Code 8-1-39-10; (2) Approval of a Transmission and Distribution Infrastructure Improvement Cost Rate Adjustment and Deferrals pursuant to Ind. Code 8-1-39-9; (3) Approval of Certain Regulatory Assets; (4) Approval of Voluntary Dynamic Pricing Riders; and (5) Approval of a new Depreciation Rate for Advanced Meters.* Cause No. 44720, Order at 23 (June 29, 2016); and *In Re: Petition of Northern Indiana Public Service Company for Approval of Petitioner's 7-Year Electric TDSIC Plan for Eligible Transmission, Distribution and Storage System Improvements, Pursuant to Ind. Code 8-1-39-10(a), For Authority to Defer Costs for Future Recovery, and Approving Inclusion of NIPSCO's TDSIC Plan Projects In Its Rate Base In Its Next General Rate Proceeding Pursuant to Ind. Code 8-102023.* Cause No. 44733, Order at 62 (July 12, 2016).

Q. WHY DOESN'T DUKE ENERGY KENTUCKY CURRENTLY HAVE AN ESM LIKE THE OTHER UTILITIES THAT OWN GENERATION?

A. Anecdotally, Duke Energy Kentucky did not historically have a need for Rider ESM because it only acquired ownership of generating assets in 2006. Prior to that point, the Company did not own any generating facilities and procured 100 percent of its load requirements via purchased power agreements. Without its own generation, Duke Energy Kentucky was not subject to any of the environmental regulations outlined in KRS 278.183 and, consequently, had no need for a Rider ESM.

As mentioned earlier, the Company began operating its own generation in January 2006. As part of the settlement of the Company's last electric rate case, the Company included all then-known environmental compliance costs in base rates and also agreed to a "stay-out" preventing it from implementing a Rider ESM for several years after the last rate case. Because East Bend was well equipped to comply with environmental regulations that existed at the time, the Company did not have any significant incremental environmental projects necessitating the implementation of an ESM. Since that time, the Company has been able to manage its costs to comply though base rates and various cost-management and efficiency initiatives.

The passage of recent environmental regulations, such as the MATS, Coal Combustions Residuals (CCR), and Electric Steam Effluent Limitation Guidelines (ELG), has made it more challenging for the Company to manage its environmental costs through base rates; therefore, the Company is now establishing Rider ESM capable of tracking incremental revenue requirements for certain environmental investments at East Bend that are approved as part of the Company's Environmental Compliance Plan, which is outlined in the testimony of Company witnesses Miller and Jett.

Q. HOW WILL RIDER ESM WORK?

A. Ms. Lawler provides testimony supporting the template being proposed in this proceeding. Generally, the Company will manage Rider ESM to include the costs of specific projects allowed under the law that are (1) incremental to compliance costs for projects that are in service and reflected as part of base rates in the test year used in this case and (2) as may be approved by the Commission going forward. As is the case for the other electric utilities with environmental surcharge mechanisms, the Company will make monthly filings once it begins to incur costs for any Commission-approved projects that are eligible for recovery under Rider ESM. So, assuming that the Commission approves rates in this proceeding to be effective April 1, 2018, the first Rider ESM filing will be made using April 2018 actual data. April 2018 data would be available in May 2018, meaning the Company would file by May 22, 2018, for Rider ESM rates effective June 1, 2018, following the procedures set forth in KRS 278.183. Additionally, the mechanism will be subject to Commission-review in six-month and two-year increments.

Q. WHAT PROJECTS IS THE COMPANY PROPOSING TO INCLUDE AS PART OF ITS ENVIRONMENTAL COMPLIANCE PLAN?

A. Mr. Miller and Ms. Jett support the Company's environmental compliance plan, including existing and proposed projects that will be included at the outset of the Rider ESM. The projects to be included in the initial Rider ESM include those projects recently approved by the Commission in Case No. 2016-00398 related to the ash pond at the Company's East Bend Generating Station. The initial Rider ESM will also include recovery of the Company's asset retirement obligation approved in Case No. 2015-00187,[9] based on a levelized recovery as described in the testimony of Company witness Cynthia S. Lee. The Company's proposal to levelize recovery will serve to mitigate the potential for abrupt changes in rates for this issue.

Q. ARE THERE OTHER COSTS THE COMPANY IS PROPOSING TO INCLUDE IN RIDER ESM?

A. Yes. With the implementation of the environmental surcharge mechanism, the Company is proposing to begin recovering all costs for EAs and incremental environmental reagents (*e.g.*, ammonia, trona, limestone). The Company has included an adjustment to remove EA costs from test year O&M expenses for base rate recovery. EAs allocable to retail load and incremental environmental reagent expenses will be recovered exclusively via Rider ESM. Any costs for EAs allocable to non-native sales will be netted against the proceeds for non-native sales as part of Rider PSM.

EA expense is significantly lower in recent years than it was at the time of the 2006 Rate Case. Nevertheless, to the extent the Company sells any emission allowances, any gains/losses would be included in Rider ESM. Because Rider ESM includes provisions for truing-up over- and under-recovery, it is necessary to

[9] Order dated, December 15, 2015.

create a regulatory asset to account for these deferrals.

IV. PREVIOUSLY APPROVED ACCOUNTING DEFERRALS

Q. WILL YOU SUMMARIZE THE ACCOUNTING DEFERRALS FOR WHICH DUKE ENERGY KENTUCKY IS SEEKING BASE RATE RECOVERY IN THIS CASE?

A. The Company has a number of accounting deferrals that the Commission has approved in prior cases. Table 1, below, is a summary of the regulatory assets, approved by the Commission, showing the projected balance to be recovered, the case number for which the regulatory asset was approved, and a reference to the revenue requirement adjustment reflecting the proposed amortization of the regulatory asset.

Table 1			
Description	**Projected Balance as of 3/31/18**	**Approved in Case No.**	**Schedule Reference**
AMI Opt Out	$263,029	2016-00152	D-2.31
East Bend Depreciation	$11,529,520	2015-00120	D-2.21
East Bend O&M	$39,162,337	2014-00201	D-2.31
Storm Cost	$4,912,800	2008-00476	D-2.31
Carbon Mgt Research	$2,000,000	2008-00308	D-2.31
AMI Meter Change-Out	$6,958,958	2016-00152	D-2.16

The Company is also seeking deferral of its rate case expenses associated with this case as well as authority to include amortization of this expense in base rates; however, Table 1 only includes those costs being sought for base rate recovery and that have been approved in prior cases.

Q. HOW IS THE COMPANY RECOMMENDING THESE DEFERRALS BE RECOVERED IN THIS RATE CASE?

A. Traditional ratemaking involves amortizing the balance of a regulatory asset over some period of time that is fair and reasonable to the customer and the shareholder. In this case, Duke Energy Kentucky is recommending an amortization of five years for recovery of the following deferrals: Carbon Management, Storm costs, and AMI Opt Out costs. For the East Bend O&M costs, the company proposes to amortize these costs over ten years. For the East Bend Depreciation deferral, the Company proposes to amortize these costs over the remaining life of the East Bend generating station, or twenty-four years. Finally, for the recovery of the meter change-out associated with the Commission-approved deployment of AMI, the Company is recommending 15 years, consistent with the Commission's order in Case No. 2016-00152.

Q. ARE THERE OTHER REGULATORY ASSETS FOR WHICH THE COMPANY IS REQUESTING RECOVERY?

A. Yes. As discussed in the testimony of Ms. Lee, Duke Energy Kentucky sought approval from the Commission to establish a regulatory asset for its legal retirement obligation associated with coal ash at East Bend. In 2015, the U.S. Environmental Protection Agency (EPA) published its new rules for the handling of CCRs. These new rules created a legal obligation for Duke Energy Kentucky as it related to the eventual retirement of its facilities to handle coal ash. Because of this legal obligation Company recorded a significant regulatory liability, on December 15, 2015, in Case No. 2015-00187, the Commission granted Duke

Energy Kentucky authority to create a regulatory asset to (1) record an asset offsetting the regulatory liability that was recorded for the ARO and (2) to record the actual costs incurred by the Company to meet the legal requirements under the CCR rule.

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO RECOVERING ARO REGULATORY ASSET FOR COAL ASH?

A. Duke Energy Kentucky is proposing to recover the cost on a levelized basis over ten years. Ms. Lee provides a summary of the costs and a schedule showing the calculation of the levelized amount.

The Company is proposing to recover this cost exclusively in its proposed Rider ESM rather than through base rates. Rider ESM has a provision for reconciliation, ensuring the Company and the Commission with a means of ensuring customers pay no more or no less than the actual cost of the asset retirement obligation.

V. COMPLIANCE WITH COMMISSION DIRECTIVES

Q. ARE YOU FAMILIAR WITH THE VARIOUS REGULATORY COMMITMENTS AND COMMISSION DIRECTIVES IMPOSED ON DUKE ENERGY KENTUCKY AS THEY RELATE TO RETAIL RATEMAKING?

A. Yes. As part of the recent mergers with Duke Energy and Progress Energy[10] and

[10] *In the Matter of the Joint Application of Duke Energy Corporation, Cinergy Corp., Duke Energy Ohio, Inc., Duke Energy Kentucky, Inc., Diamond Acquisitions Corporation, and Progress Energy Inc., for Approval of the indirect Transfer of Control of Duke Energy Kentucky, Inc.,* Case No. 2011-00124 KY. P.S.C. Order (Oct. 28, 2011).

Piedmont Corporation (Piedmont),[11] there are a few commitments made by Duke Energy Kentucky as it relates to the implications of these mergers on retail rates.

Q. PLEASE LIST THE COMMITMENTS THAT RELATE TO RATE-MAKING AND COST RECOVERY AND EXPLAIN HOW THE COMPANY HAS COMPLIED WITH THESE COMMITMENTS IN THIS CASE?

A. As part of the resolution of Case No. 2011-0124, Duke Energy Kentucky made numerous commitments. I am addressing the specific commitments that touch on the Company's rate making and cost recovery:

1) Commitment 3: The payment of Progress Energy Stock shall be excluded from the books of Duke Energy Kentucky for retail ratemaking purpose. The Company has not included any such payments in the Company's test year budget.

2) Commitment No. 4: Any acquisition premium paid by Duke Energy for the Progress Energy stock shall not be pushed down to Duke Energy Kentucky. The Company has not included any such payments in its test year budget.

3) Commitment No. 5: No change in control payments shall be allocated to Duke Energy Kentucky retail rate payers. The Company has not included any such payments in its test year budget.

4) Commitment No. 14: The Commission shall have ongoing jurisdiction over the Company's capital structure, financing and cost of capital. The Company has presented its capital structure and costs of capital for the Commission's

[11] *In the Matter of the Application of Duke Energy Kentucky, Inc., for a Declaratory Order,* Case No. 2015-00413 (Ky. P.S.C. March 7, 2016).

review in this proceeding.

5) Commitment No. 15: The merger will have no adverse impact on the base rates or the operation of the fuel adjustment clause, gas cost recovery and demand side management clause of Duke Energy Kentucky. There are no such adverse impacts caused by the merger.

6) Commitment No. 16: Duke Energy Kentucky will not seek a higher rate or return on equity than would have been sought if the merger transaction had not occurred. Duke Energy Kentucky presents the direct testimony of Roger A. Morin Ph.D., whose analysis supports the Company's requested return on equity.

7) Commitment No. 17: The accounting and ratemaking treatments of Duke Energy Kentucky's excess accumulated deferred income taxes (ADITs) will not be affected by the merger of Duke Energy and Progress Energy. As demonstrated by the Company's application in this proceeding, there has been no impact to the Company's ADITs.

8) Commitment No. 22, Duke Energy Kentucky will pay dividends only out of retained earnings and to maintain a capital structure that maintains a minimum of thirty-five (35) percent equity. As demonstrated by its application, the Company has maintained an equity ratio that is greater than 35 percent equity. Further, the Company has only paid its dividends out of retained earnings.

9) Commitment No. 44, if the merger between Duke Energy and Progress Energy was not completed, Kentucky customers will not bear any costs of the failed transaction. As the Commission is aware, the merger between Duke Energy and Progress Energy was completed, so there were no termination payments made

or received.

10) Commitment 47, Duke Energy Kentucky committed to aggressively pursue cost-effective demand-side management (DSM) and energy efficiency (EE) programs and to deploy such programs using industry best practices in Kentucky. The Company continues to evaluate and offer cost effective DSM and EE programs, which are filed at least annually with the Commission.

11) Commitment 49, no costs to achieve the merger transaction will be recovered from Duke Energy Kentucky ratepayers. As evidenced by the Company's filing, no costs to achieve the merger transactions have been included in the Company's application.

Recently, in Case No. 2015-00413 regarding the merger between Duke Energy and Piedmont Natural Gas Company, Duke Energy Kentucky reasserted its commitment that in future rate cases, it will not seek a higher rate or return on equity than would have been sought if the proposed acquisition of Piedmont had not occurred. The Company has presented the Direct Testimony of Dr. Roger A. Morin to support the Company's requested return on equity in this proceeding. Dr. Morin's testimony and recommended range of a reasonable return is accompanied by a thorough analysis that is not reliant upon the Company's history of mergers.

VI. REASONABLENESS OF REQUEST

Q. IS THE COMPANY'S REQUESTED RATE RELIEF REASONABLE?

A. Yes. Duke Energy Kentucky's retail electric rates are currently the lowest in the Commonwealth and among the lowest in the country. That enviable position owes, in part, to the Company's focus on cost control and, in part, to the Commission's foresight in encouraging Duke Energy Kentucky to acquire its own generation near the beginning of this century. The low-cost generation acquired at that time has been a significant factor in Duke Energy Kentucky maintaining its low rates over the years. The more recent acquisition of DP&L's share of East Bend also contributes to the Company's ability to maintain its low-cost position.

VII. FILING REQUIREMENTS SPONSORED BY WITNESS

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

A. FR 16(1)(b)(1) is Duke Energy Kentucky's statement of the reasons for the proposed increase.

VIII. CONCLUSION

Q. HAVE YOU REVIEWED DUKE ENERGY KENTUCKY'S APPLICATION IN THESE PROCEEDINGS?

A. Yes. I have also reviewed the testimony and attachments of all Company witnesses. I believe that the Company's total electric revenue requirement is properly computed, the costs of service are properly allocated to customer classes, and the rate design is equitable.

Q. DO YOU BELIEVE DUKE ENERGY KENTUCKY'S RATE REQUEST IS REASONABLE?

A. Yes.

Q. WERE ATTACHMENTS WDW-1, WDW-2, AND FR 16(1)(b)(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, William Don Wathen, Jr., Director of Rates & Regulatory Strategy, 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.

William Don Wathen Jr., Affiant

Subscribed and sworn to before me by William Don Wathen, Jr., 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

Schedule 1

DUKE ENERGY KENTUCKY
FERC TRANSMISSION COST RECONCILIATION RIDER
FOR SEPTEMBER 20XX - NOVEMBER 20XX BILLING

A.	Revenue Requirement for Rider FTR (Schedule 2, Line E)		TBD	
B.	Retail Sales (Schedule 3, Line B)	÷	-	
C.	Rider FTR Rate (Line A ÷ Line B)		0.000000	($/kWh)

Effective Date for Billing: ______________________

Submitted by: ______________________

Title: ______________________

Date Submitted: ______________________

Schedule 2

DUKE ENERGY KENTUCKY
INVOICED TRANSMISSION COSTS

Expense Year: ___________

	PJM Billing Line Item(s)		Apr-XX	May-XX	Jun-XX	Dollars ($)
A. Current Charges for Retail Load (a)						
Network Integrated Transmission Service	1100 / 2100	(+)	$ -	$ -	$ -	$ -
Point-to-Point Transmission Service	1130 / 2130 1140 / 2140	(+)	-	-	-	-
Regional Transmission Expansion Planning	1108/ 2108	(+)	-	-	-	-
Transmission Owner Scheduling System Control & Dispatch	1320 / 2320 / 1450	(+)	-	-	-	-
PJM Market Administrative Costs	1301 - 1319 / 1440-1448	(+)	-	-	-	-
Other		(+)	-	-	-	-
B. Total Recoverable Costs			$ -	$ -	$ -	$ -
C. Amount Included in Base Rates (per quarter)		(-)				4,740,941 [(b)]
D. Over-/((Under-)Recovery of Prior Period FTR Costs (Schedule 4, Line D)		(+)				-
E. Amount to be Recovered in Rider FTR (B - C + D)						TBD

Note: [(a)] Sum of net charges for most recent actual period.
[(b)] As approved in Case No. 2017-000321.

Costs included in Base Rates:

Network Integrated Transmission Service	$ 12,964,731
Point-to-Point Transmission Service	(144,996)
Regional Transmission Expansion Planning	4,030,393
Transmission Owner Scheduling System Control & Dispatch	396,978
PJM Administrative Costs	1,716,657
Other	-
Total Costs Included in Base Rates	$ 18,963,763

Schedule 3

DUKE ENERGY KENTUCKY
RETAIL SALES SCHEDULE

	kWh Sales Current Month
A. Sales (kWh) from FAC Filing (FAC Schedule 3, Line C)	
April	-
May	-
June	-
B. Total Sales	-

Schedule 4

DUKE ENERGY KENTUCKY
RECONCILATION OF FTR COSTS TO FTR REVENUE FOR PRIOR PERIOD

	Amount
A. Rider FTR Revenue Collected in Prior Year	$ -
B. Rider FTR Revenue Requirement in Prior Year	-
C. Prior Period Carryforward	-
D. Over-/(Under-) Recovery for Prior Period	$ -

CONFIDENTIAL ATTACHMENT WDW-2 FILED UNDER SEAL OF PETITION FOR CONFIDENTIAL TREATMENT

Direct Testimony of
Alexander "Sasha" J.
Weintraub, 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

ALEXANDER "SASHA" J. WEINTRAUB, PH.D.

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 Alexander (Sasha) J. Weintraub, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Progress, LLC (Duke Energy Progress), as Senior Vice President of Customer Solutions. Duke Energy Progress provides various administrative and other services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky), and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Engineering from Rensselaer Polytechnic Institute, a Master's degree in Mechanical Engineering from Columbia University and a Ph.D. in Industrial Engineering from North Carolina State University.

I assumed my current position as Senior Vice President of Customer Solutions in October 2015. Previously, I was Senior Vice President of Market Solutions for Duke Energy. In that role, I was responsible for economic development, large business customers, rate design and analysis, customer regulatory strategy and analytics, data analytics, and wholesale power sales for Duke Energy. I have also served as Vice President of Fuels and Systems Optimization for Duke Energy. In this role, I led the organization responsible for the purchase and delivery of coal, natural gas, and oil to Duke Energy's generation fleet, as well as the wholesale trading function related to power and natural gas. I managed the fleet and system optimization, energy supply analytics, and power trading and dispatch functions.

Prior to working at Duke Energy, I was employed by Progress Energy, Inc. (Progress Energy). I joined Progress Energy in 1999 and held various leadership roles, including Director of Business Operations and Strategic Planning, and was employed as an operational auditor for Progress Energy Service Company. From 2003 to 2005, I was Director of Coal Marketing and Trading for Progress Fuel Corporation, a former subsidiary of Progress Energy, where I managed the marketing activities of the unregulated coal and synthetic fuel operations of Progress Energy. In 2005, I became Vice President of Fuels and Power Optimization for Progress Energy. Following the Duke Energy/Progress Energy merger in July 2012, I was named Vice President of Fuels and Systems Optimization for Duke Energy.

Q. PLEASE DESCRIBE YOUR DUTIES AS SENIOR VICE PRESIDENT, CUSTOMER SOLUTIONS.

A. As Senior Vice President of Customer Solutions, I am responsible for aligning customer-focused products, programs, and services to deliver a personalized end-to-end customer experience that positions Duke Energy to meet customers' ever evolving needs. My duties include development of retail programs, enhanced customer solutions initiative, rate design and analysis, customer regulatory strategy and analytics, and data analytics for all of Duke Energy's regulated utility operations.

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

A. Yes. I recently provided testimony in support of Duke Energy Kentucky's application for a certificate of public convenience and necessity for deployment of an advanced metering infrastructure (AMI) in Case No. 2016-000152 (Metering Upgrade).

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

A. The purpose of my testimony is to discuss Duke Energy Kentucky's proposals for tariff changes to implement new enhanced customer solutions (ECS) programs that will allow customers to have greater convenience, transparency, and control over their energy usage and the utility bills they receive. To do this, I begin with a discussion of Duke Energy's focus on customers through its Customer Solutions organization.

II. OVERVIEW OF CUSTOMER CARE SOLUTIONS

Q. PLEASE EXPLAIN THE DUKE ENERGY CUSTOMER SOLUTIONS ORGANIZATION AND ITS PURPOSE.

A. The Duke Energy Customer Solutions Organization's purpose is to deliver a personalized customer experience by aligning customer-focused programs and services that offer customers greater convenience, control, choice, and transparency. The Customer Solutions organization focuses on the collective customer base for all of Duke Energy's utility operating companies, as well as the specific jurisdictions, to find ways to enhance the overall customer experience. The goal of the organization is to improve customer service and satisfaction.

Q. WHY IS THE DUKE ENERGY CUSTOMER SOLUTIONS ORGANIZATION IMPORTANT?

A. Duke Energy has more than 7.4 million retail customers representing a total population of approximately 24 million customers across its seven state utility territories. As technologies emerge and evolve, Duke Energy's customers have growing expectations of their utility service provider. The Customer Solutions Organization strives to understand these expectations and develop ways to meet those expectations and give customers the ability to have greater control over how they use energy and interact with Duke Energy.

Q. PLEASE DESCRIBE THESE CUSTOMER EXPECTATIONS.

A. Duke Energy's internal and external research, as supported by Duke Energy Kentucky witness James P. Henning, has shown that its residential electric customers are concerned about reliability, cost, predictability of cost, transitioning to cleaner energy sources, and control. Perhaps even more importantly, Duke Energy's customers want better communication from their utility related to these key areas of concerns. The Company must find ways to communicate more proactively with its customers and to give them more options and control. Supplying customers with more updates during outages, sending them usage alerts, and offering them alternative payment plans, and allowing them to choose their own monthly payment date are all services that Duke Energy Kentucky would like to use in order to meet those expectations and continue to be a trusted energy provider.

The Company strives to be a leader in the industry with respect to advanced grid solutions, including AMI deployment, and to proactively ensure that the Company's grid investments exceed customer expectations.

III. SPECIAL SERVICES

Q. PLEASE SUMMARIZE THE NATURE OF THE NEW PRODUCTS AND SERVICES THAT DUKE ENERGY KENTUCKY IS PROPOSING IN THIS PROCEEDING?

A. The Company has been identifying and developing new flexible billing alternatives, new services, and a suite of ECS to provide to its customers. Many of these new billing alternatives and programs are enabled by the customer data made available through the recently approved Metering Upgrade. All of these new billing alternatives, services, and ECS programs are optional and are designed to give customers options that provide them with greater convenience, transparency, choice, and control over their energy usage, while also giving them the opportunity to budget, save time, and money.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY ECS.

A. ECS are customer value-driven programs and services that customers want, need, and are growing to expect from their utility. As technology has developed, so has the expectation of our utility customers who desire greater insight and control over their energy consumption and billing. These programs and services are often mentioned in customer satisfaction surveys as offerings that drive higher customer satisfaction. Many of these programs are enabled through the more frequent customer usage data collection and leveraging the electric interval information that will be obtained and provided to customers through the Company's recently approved Metering Upgrade.

Q. PLEASE DESCRIBE THE NEW FLEXIBLE BILLING PROGRAMS THE COMPANY IS EITHER IMPLEMENTING OR PROPOSING TO IMPLEMENT IN THIS PROCEEDING.

A. Duke Energy Kentucky is proposing to implement two new flexible billing options for customers, Pick Your Own Due Date and Fixed Bill. These programs are designed to provide our customers, who desire to take a more active role in managing their energy usage, greater flexibility and control over their utility bill. The Pick Your Own Due Date will be available immediately to customers with AMI meters and who do not elect to opt out of the Company's Metering Upgrade. The availability of the Fixed Bill product will not be dependent upon the Metering Upgrade technology and will be available upon Commission approval.

Q. PLEASE DESCRIBE PICK YOUR OWN DUE DATE.

A. Pick Your Own Due Date is an optional AMI-enabled program that allows customers to choose a monthly due date that best aligns with their personal situation. Today, Duke Energy Kentucky's customers are assigned a billing cycle based upon Duke Energy Kentucky's ability to deploy and manage its meter reading personnel to attempt to manually read each and every mechanical meter on a monthly basis. The cycle is determined based upon geographical areas to more efficiently manage meter reading costs. Once a customer is assigned a specific meter reading cycle, the cycle cannot be changed. This results in the customer having no control over when their utility bill is due during the month.

Pick Your Own Due Date will give customers greater flexibility, choice, and control by allowing them to shift their payment due date to better align with their unique financial situation (*e.g.,* to coincide with paycheck dates, Social Security payments). Customers will be able to decide which day of the month they prefer to pay their electricity bill without being penalized. The Company is enabling this capability to customers immediately upon installation of a new AMI electric meter. There will be no noticeable changes to the customer's service other than a billing cycle alignment period that may mean one billing cycle month is longer or shorter than normal to sync up to the newly requested billing due date.

Q. WHAT IS FIXED BILL AND HOW DOES IT WORK.

A. Fixed Bill is a voluntary billing product for residential customers seeking certainty regarding their monthly electric bill. As the name suggests, Fixed Bill is a flat monthly billing charge for electric service that is "guaranteed" for twelve months. Unlike the Company's current budget billing plan, the fixed bill customer will not be at risk for any true-up at the end of the twelve month period. Instead, the risk of weather and commodity volatility that is present in a conventional usage-based monthly utility bill is hedged by the customer through a small premium that is calculated as part of the flat monthly charge. Experience in other jurisdictions has shown that a significant population of customers are willing to pay a small premium for the certainty that their electric utility bill will be predictable, equal and not subject to the risk of a true-up where the customer has the risk of owing a large sum at the end of some cycle. Every twelve months, the Company will determine a new charge to the customer should they choose to remain enrolled in the program. The Company will then factor any changes in usage patterns for the customer as part of that new monthly bill.

Q. DO ANY OF DUKE ENERGY KENTUCKY'S REGULATED UTILITY AFFILITES OFFER A FIXED BILL PRODUCT?

A. Yes. Currently Duke Energy Indiana offers the program to its customers.

Q. WHAT HAS BEEN ITS EXPERIENCE WITH FIXED BILL?

A. Duke Energy Indiana's offering of Fixed Bill has been extremely successful. The program has approximately 60,000 customers participating in it and has a customer retention rate above 95 percent. When surveyed in spring of 2016, a sample of Fixed Bill program participants indicated that they were very satisfied with the program, with 88 percent of respondents saying they were highly satisfied with the program. In fact 78 percent of the respondents indicated that their participation in Fixed Bill had a positive effect on their overall satisfaction with Duke Energy Indiana.

Q. WHY WOULD A CUSTOMER WANT A FIXED BILL PRODUCT WHEN OTHER BUDGET BILLING ALTERNATIVES ARE AVAILABLE?

A. Duke Energy has heard from many customers across its different utilities that many customers elect not to participate in the budget billing program due to the fear of having to pay a large true-up at the end of the year outweighs the benefit of paying a known amount each month. The Fixed Bill program alleviates that concern, provides greater bill certainty, and helps customers to better budget for their electricity bill over the course of a year.

Q. DOES A FIXED BILL PRODUCT DISCOURAGE ENERGY EFFICIENCY AND DEMAND SIDE MANAGEMENT FOR CUSTOMERS?

A. Experience shows that Fixed Bill has no greater impact on energy efficiency and demand side management philosophies of customers than other budget billing programs currently available. While the program does eliminate the immediate bill impact associated with usage, it is not vastly different from budget billing which also eliminates monthly bill impacts associated with usage. The Fixed Bill Program simply eliminates the true up associated with any variance in usage from a prior year, but the customer's Fixed Bill amount for the next year will still be positively influenced (reduced) if customers become more energy efficient and reduce usage. Additionally the Company is confident that with 37% of its total residential customers currently participating in the MyHER energy efficiency program, that they will have a timely means by which to track their usage and see if their participation in Fixed Bill is causing them to increase their energy usage, even if the monthly bill does not change. Finally, in a Duke Energy Indiana survey of Fixed Bill and non-Fixed Bill customers, the Company found that overall awareness of energy efficiency programs offered was the same and Fixed Bill participants had a higher participation rate in energy efficiency programs than non-participants. For example, 16 percent of Fixed Bill customers participated in the Residential Energy Assessment Program (Home House Call), and only 11 percent of the non-participants took advantage of this valuable program offering a home audit.

Q. WHAT ADDITIONAL ECS PROGRAMS AND SERVICES IS THE COMPANY SEEKING TO INTRODUCE AT THIS TIME?

A. The Company is also proposing to implement two new ECS services that are designed to provide customers with greater control and transparency in their utility consumption and service. These products are Usage Alerts and Outage Alerts with AMI.

Q. PLEASE DESCRIBE THE USAGE ALERTS PROGRAM.

A. Usage Alerts is an AMI-enabled program that provides customers with a mid-cycle report of their usage to date, along with projections of the end-of-cycle bill, based on historical usage and weather data. Customers will have the opportunity to opt in to receive threshold-based reports. This functionality allows a customer to input their preferred threshold and receive notifications as they approach 75 percent and 100 percent of their preset threshold. Customers can receive these messages via email and/or text message (SMS). The Usage Alerts program will provide customers with greater transparency into their past and estimated future usage and will conveniently alert customers via email and text when they are approaching or have exceeded their pre-selected usage level for the month. Customers enrolled in this program will be able to view the amount of electricity they have used so far during the current billing cycle, as well as the estimated cost of this usage. This program can help customers avoid unexpected high bills.

Q. PLEASE DESCRIBE THE OUTAGE ALERTS WITH AMI PROGRAM.

A. The Outage Alerts with AMI program will allow customers to receive enhanced proactive outage and restoration information regarding their service. This program will allow the Company to provide even more timely and accurate information than what is currently available. While Duke Energy Kentucky does have an outage message system, currently in Kentucky, the information is at a very high system level and in many cases requires the customer to make Duke aware of their outage. With the AMI-enabled capability, Duke Energy Kentucky will be able to communicate with enrolled customers pro-actively during outage events with more specific information regarding their service and making them more aware of the outage, the cause, and the estimated time of restoration.

Q. ARE THESE ECS CUSTOMER OFFERINGS MANDATORY FOR CUSTOMERS TO USE?

A. No, it is not mandatory for customers to use, enroll, or participate in any ECS customer offerings. It is still the customer's decision to participate in these offerings.

Q. WHEN WILL THESE PROGRAMS AND SERVICES BE AVAILABLE TO DUKE ENERGY KENTUCKY CUSTOMERS?

A. Most of the ECS programs will be available once the Metering Upgrade is completed. The Company is timing the deployment of the majority of these ECS products to align with the completion of its Metering Upgrade. For example, Pick Your Own Due Date and Usage Alerts are being developed for other Duke Energy jurisdictions that presently have similar AMI technology deployments as that selected by Duke Energy Kentucky. As such, those two programs are anticipated to be available immediately in Kentucky upon completion of the Metering Upgrade.

Q. WHICH CUSTOMERS WILL BE ABLE TO TAKE ADVANTAGE OF THESE PROGRAMS?

A. These programs could be offered to eligible residential and small and medium businesses. Eligibility will vary by program.

Q. FOR WHICH OF THE BILLING OPTIONS AND ECS PROGRAMS IS DUKE ENERGY KENTUCKY SEEKING AUTHORIZATION IN THIS PROCEEDING?

A. Duke Energy Kentucky is seeking the Commission's authorization to begin offering the Fixed Bill. That program will be described in the Company's billing tariff as supported by Duke Energy Kentucky witness Bruce Sailers. The Company believes that the Pick Your Own Due Date and outage and usage alert programs do not require specific approval as they do not involve any tariff changes or substantial changes to the Company's provision of service. I mention these programs in this proceeding as an update to the Commission of the efforts of the Company to provide customers with greater control and information regarding their energy consumption. Some of the programs I described, such as Pick Your Own Due Date, will be available upon completion of the Metering Upgrade, while others are still in the design phase, but are anticipated to potentially be ready in 2018.

Q. ARE THERE OTHER POTENTIAL PROGRAMS, PRODUCTS, AND SERVICES THAT YOU FORESEE BEING OFFERED BY DUKE ENERGY KENTUCKY IN THE FUTURE?

A. There is significant potential for the electric distribution grid through innovation and technological advances. Thus, I anticipate that Duke Energy Kentucky will explore new products, services, and offerings that are a complement to, or enabled by, an intelligent, interactive grid.

IV. CONCLUSION

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

A. Yes.

VERIFICATION

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

The undersigned, Alexander (Sasha) J. Weintraub, Senior Vice President of Customer Solutions, 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.

____
Alexander (Sasha) J. Weintraub Affiant

Subscribed and sworn to before me by Alexander (Sasha) J. Weintraub on this 17TH day of AUGST, 2017.

Carla Sechrest
NOTARY PUBLIC

CARLA SECHREST
Notary Public
Rowan County
NORTH CAROLINA

My Commission Expires:
7/27/2019

Direct Testimony of
James E. Ziolkowski

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

JAMES E. ZIOLKOWSKI

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 James E. Ziolkowski, 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, Rates & Regulatory Planning. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Mechanical Engineering from the U.S. Naval Academy in 1979 and a Master of Business Administration degree from Miami University in 1988. I am also a licensed Professional Engineer in the state of Ohio. I received certification as a Chartered Industrial Gas Consultant in 1994 from the Institute of Gas Technology and the American Gas Association. I have attended the EUCI Cost of Service seminar.

After graduating from the Naval Academy, I attended the Naval Nuclear Power School and other follow-on schools. I served as a nuclear-trained officer on various ships in the U.S. Navy through 1986. From 1988 through 1990, I worked for Mobil Oil Corporation as a Marine Marketing Representative in the New York City area.

I joined The Cincinnati Gas & Electric Company n/k/a Duke Energy Ohio, Inc., (Duke Energy Ohio) in 1990 as a Product Applications Engineer, in which capacity I designed and managed some of Duke Energy Ohio's demand side management programs, including Energy Audits and Interruptible Rates. From 1996 until 1998, I was an Account Engineer and worked with large customers to resolve various service-related issues, particularly in the areas of billing, metering, and demand management. In 1998, I joined the Rate Department, where I focused on rate design and tariff administration. I was appointed to my current position in January 2014.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR RATES & REGULATORY PLANNING.

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

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

A. Yes.

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

A. I discuss the Commission's directives from the Company's previous retail electric base rate case relating to cost of service studies. I sponsor Schedules B-7, B-7.1, B-7.2, D-3, D-4, and D-5 in response to Filing Requirement FR 16(8)(b) and FR 16(8)(d), respectively. I also support the electric cost of service studies identified in response to Filing Requirement FR 16(7)(v).

II. PRIOR COMMISSION DIRECTIVES

Q. DID THE COMMISSION ISSUE ANY DIRECTIVES IN THE COMPANY'S PRIOR ELECTRIC RATES CASES RELATING TO THE COST OF SERVICE STUDIES FOR THE COMPANY'S FUTURE RATE CASES?

A. Yes. The Commission recommended in Case No. 91-00370 that, in future rate cases, the Company should separate out distribution plant into primary and secondary components for its Cost of Service Study. If not feasible, then the Commission directed the Company to explain in testimony the reasons why it could not do so. The Commission also directed the Company to file multiple costs of service studies that use, among other things, demand allocation methods from each of the peak demand, energy weighting, and time-differentiated families of production plant allocation methodologies.

Q. HAS THE COMPANY ADDRESSED THOSE RECOMMENDATIONS IN PREPARING THE COST OF SERVICE STUDIES FOR THIS PROCEEDING?

A. Yes. I will discuss the Company's responses in more detail later in my testimony.

III. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE SCHEDULES B-7 AND D-3.

A. These schedules report the allocation factors used to determine the jurisdictional percentages of electric plant, expenses, *etc.*, necessary to allocate the amount of the proposed new electric rates between jurisdictional and non-jurisdictional customers. These schedules indicate that 100 percent of the costs are jurisdictional, because Duke Energy Kentucky does not provide service to any non-jurisdictional electric customers.

Q. PLEASE DESCRIBE SCHEDULES B-7.1 AND D-4.

A. These schedules are the support for Schedules B-7 and D-3 described above. They provide the basis for the actual jurisdictional allocation factors.

Q. PLEASE DESCRIBE SCHEDULES B-7.2 AND D-5.

A. These schedules explain changes made to the jurisdictional allocation from the Company's prior electric rate proceeding in Case No. 2006-00172.

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

A. FR16(7)(v) contains 25 schedules: Schedules FR16(7)(v)-1 through FR 16(7)(v)-25 which represent the fully allocated, embedded cost of service study by rate class. I discuss these filing requirements in greater detail in my testimony below.

IV. COST OF SERVICE STUDIES

Q. WHAT IS THE PURPOSE OF A COST-OF-SERVICE STUDY?

A. A cost-of-service study is an analytical tool used in traditional utility rate design to allocate costs to different classes of customers. When the process of preparing a cost-of-service study is completed, the resulting class cost-of-service study can (1) assist in determining the revenue requirement for the services offered by a utility; (2) analyze, at a very detailed level, the costs imposed on the utility's system by different classes of customers; (3) show the total costs the company incurs in serving each retail rate class, as well as the rate of return on capitalization earned from each class during the test year; and (4) establish cost responsibility that makes it possible to determine just and reasonable rates based on costs.

Q. WHAT INFORMATION DID THE COMPANY USE TO DEVELOP THE COST ALLOCATION FACTORS FOR THE COST OF SERVICE STUDIES USED IN THIS PROCEEDING?

A. The test year for this proceeding is the twelve months ending March 31, 2019, which is comprised of forecasted test period data. The development of the test year allocation factors is primarily based on historical data for the twelve months ended December 2016. Otherwise, forecasted test year information was used as appropriate. I will discuss the actual development of the various allocation factors used in this proceeding later in my testimony.

Q. HAS THE COMPANY PREPARED MULTIPLE COSTS OF SERVICE STUDIES?

A. Yes. The Company prepared three Class Cost of Service Studies that contain essentially the same data, except that different methodologies were used to develop the allocation factor for the demand component of Production-related costs. The demand allocation methods are as follows: (1) the Average of the Twelve (12) Coincident Peaks (12 CP) method; (2) the Average and Excess (A&E) method; and (3) the Summer / Non-Summer (S/NS) method.

Q. PLEASE DESCRIBE THE DEMAND METHODOLOGIES USED IN THESE COST OF SERVICE STUDIES.

A. The 12 CP method is designed to allocate capacity related costs to the customer classes using the system during maximum system load. The allocation of capacity costs to each customer class is based on the class load contribution to the maximum peak, at the time of peak, regardless of what their respective loads were at other times of the day.

The A&E method, also referred to as the "used and unused capacity method," recognizes both the class average use of the system capacity and the class contribution to the capacity required to meet the maximum system load. The allocation of capacity costs are allocated in a two part formula.

The "class-used" capacity component is the proportion of the class's respective average hourly kilowatt-hour (kWh) sales to the total average hourly sales. The "class-unused" capacity is the class excess hourly peak demand contribution ratio, which is the difference between the class average hourly demands and the hourly class peak demands. The used and unused capacity factors for each class are combined to allocate capacity costs to the respective rate classes.

The S/NS method is a time-differentiated method designed to allocate capacity costs based on the weighted class average coincident peak demand contributions during the maximum system load for the summer and non-summer months. The S/NS demand ratios allocate 37.69 percent of capacity costs using the class average coincident peaks for the four summer months, June, July, August and September, and the remaining 62.31 percent of capacity costs using average of the

12 monthly class coincident peaks for each rate group. The summer / non-summer capacity cost split was determined by the ratio of the annual energy delivered during the on and off-peak periods for each month.

Q. DID YOU COMPARE THE CLASS DEMAND RATIOS FOR EACH OF THE DEMAND METHODOLOGIES?

A. Yes. Attachment JEZ-1 shows the demand ratios for the different methods. Attachment JEZ-2 shows the rate impacts using the different methods.

Q. BASED UPON YOUR COMPARISON OF THE 12 CP, A&E AND S/NS METHODOLOGIES, WHICH DO YOU RECOMMEND THE COMMISSION APPROVE IN THIS PROCEEDING?

A. I recommend using the Average 12 CP methodology for three reasons. First, the 12 CP method is generally accepted in the utility industry and was approved by the Commission in the Company's last electric base rate case. The 12 CP demand methodology has been used in other jurisdictions including Duke Energy Ohio's and Duke Energy Indiana's rate proceedings. Second, this methodology recognizes that Duke Energy Kentucky's current generating facilities are in place precisely to meet the monthly maximum peak loads of customers. Third, there was no compelling reason to adopt a new methodology. Rate subsidies will generally occur among customer classes, regardless of the cost of service methodology used. Changing to either the A&E or S/NS methodology will not change this fact. The Company believes that the use of the 12 CP methodology is the appropriate means to align capacity costs with the customer classes that are imposing the costs.

Q. PLEASE DESCRIBE THE ELECTRIC COST OF SERVICE STUDY.

A. The electric cost of service study contained in Schedules FR-16(7)(v)-1 through FR-16(7)(v)-25 is an embedded, fully allocated cost of service study by rate class for the test period ended March 31, 2019. In preparing the cost of service study, I used information provided by other Company employees. The cost of service study functionalizes, classifies, and allocates cost items such as plant investment, operating expenses, and taxes to the various customer classes and calculates the revenue responsibility of each class. Finally, the cost of service study calculates the revenue responsibility of each rate class required to generate the recommended rate of return.

Q. PLEASE DESCRIBE HOW THE COST OF SERVICE STUDY IS ORGANIZED IN SCHEDULES FR-16(7)(v)-1 THROUGH SCHEDULE FR-16(7)(v)-25.

A. The schedules provided in the cost of service study are organized as shown in the table below. The detailed calculation and derivation of the allocation factors utilized in the cost of service study are included in the workpapers filed in these proceedings.

Table 1		
Schedule	Page No.	Description
Schedule 1	1	Summary of Results
Schedule 2	2	Gross Plant in Service
Schedule 3	3	Depreciation Reserve
Schedule 4	4	Net Electric Plant in Service
Schedule 5	5	Subtractive Rate Base Adjustments
Schedule 5.1	6	Additive Rate Base Adjustments
Schedule 5.2	7	Working Capital
Schedule 6	8	O&M Expenses
Schedule 6.1	9	O&M Expenses
Schedule 7	10	Depreciation Expense
Schedule 8	11	Taxes Other Than Income Taxes
Schedule 9	12	Federal Income Tax Based on Return
Schedule 9.1	13	State Income Tax Based on Return
Schedule 10	14	Cost of Service Computation
Schedule 11	15	ROR, Tax Rates & Special Factors
Schedule 12	16	Allocation Factors
Schedule 12.1	17	Allocation Factors
Schedule 12.2	18	Allocation Factors

Q. WHAT JURISDICTIONAL RATE CLASSES WERE USED IN THE CLASS COST OF SERVICE STUDY?

A. The cost of service is organized showing the following rate classes:

Residential: (Rate RS);

Secondary Distribution Small: (Rates DS, GS-FL, EH and SP);

Secondary Distribution Large: (Rates DT);

Primary Distribution: (Rate DT and DP);

Transmission: (Rates TT);

Lighting: (Rates NSU, NSP, OL, SC, SE, SL, TL and UOLS combined); and

Other: (Flood Control Water Pumping Stations).

Q. WHAT ARE THE ELEMENTS OF A COST OF SERVICE STUDY?

A. Much like the components of the overall revenue requirement, the elements of a cost of service study consist of the following elements, which are allocated to each function, classification and rate class:

Operating & Maintenance Expense
+ Depreciation
+ Other Taxes
+ Federal Income Tax
+ State Income Tax
+ Return (Jurisdictional Capitalization x Rate of Return (ROR))
- <u>Revenue Credits</u>
= Class Revenue Requirement or Cost of Service

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-1.

A. Schedule FR-16(7)(v)-1 is a functional cost of service study that separates the cost items into the production, transmission and distribution functions.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-2.

A. Schedule FR-16(7)(v)-2 is a classified cost of service study that separates the cost items contained in the production function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-3.

A. Schedule FR-16(7)(v)-3 is an allocated cost of service study that allocates the cost items contained in the production demand classification from Schedule FR-16(7)(v)-2 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-4.

A. Schedule FR-16(7)(v)-4 is an allocated cost of service study that allocates the cost items contained in the production energy classification from Schedule FR-16(7)(v)-2 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-5.

A. Schedule FR-16(7)(v)-5 is an allocated cost of service study that allocates the cost items contained in the production customer classification from Schedule FR-16(7)(v)-2 to the various rate groups. As is evident on the schedule, there is no production costs classified as customer related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-6.

A. Schedule FR-16(7)(v)-6 is a classified cost of service study that separates the cost items contained in the transmission function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-7.

A. Schedule FR-16(7)(v)-7 is an allocated cost of service study that allocates the cost items contained in the transmission demand classification from Schedule FR-16(7)(v)-6 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-8.

A. Schedule FR-16(7)(v)-8 is an allocated cost of service study that allocates the cost items contained in the transmission energy classification from Schedule FR-16(7)(v)-6 to the various rate groups. As is evident on the schedule, there is no transmission costs classified as energy related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-9.

A. Schedule FR-16(7)(v)-9 is an allocated cost of service study that allocates the cost items contained in the transmission customer classification from Schedule FR-16(7)(v)-6 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-10.

A. Schedule FR-16(7)(v)-10 is a classified cost of service study that separates the cost items contained in the distribution function on Schedule FR-16(7)(v)-1 between the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-11.

A. Schedule FR-16(7)(v)-11 is an allocated cost of service study that allocates the cost items contained in the distribution demand classification from Schedule FR-16(7)(v)-10 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-12.

A. Schedule FR-16(7)(v)-12 is an allocated cost of service study that allocates the cost items contained in the distribution energy classification from Schedule FR-16(7)(v)-10 to the various rate groups. As is evident on the schedule, there is no distribution costs classified as energy related.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-13.

A. Schedule FR-16(7)(v)-13 is an allocated cost of service study that allocates the cost items contained in the distribution customer classification from Schedule FR-16(7)(v)-10 to the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-14.

A. Schedule FR-16(7)(v)-14 is a total class cost of service study that sums the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-4, FR-16(7)(v)-5, FR-16(7)(v)-7, FR-16(7)(v)-8, FR-16(7)(v)-9, FR-16(7)(v)-11, FR-16(7)(v)-12 and FR-16(7)(v)-13, by the various rate groups.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-15.

A. Schedule FR-16(7)(v)-15 is a classified cost of service study for the residential class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-16.

A. Schedule FR-16(7)(v)-16 is a classified cost of service study for the Distribution Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-17.

A. Schedule FR-16(7)(v)-17 is a classified cost of service study for the GSFL Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-18.

A. Schedule FR-16(7)(v)-18 is a classified cost of service study for the EH Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-

16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-19.

A. Schedule FR-16(7)(v)-19 is a classified cost of service study for the SP Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-20.

A. Schedule FR-16(7)(v)-20 is a classified cost of service study for the DT Secondary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-21.

A. Schedule FR-16(7)(v)-21 is a classified cost of service study for the DT Primary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-22.

A. Schedule FR-16(7)(v)-22 is a classified cost of service study for the Distribution Primary class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-23.

A. Schedule FR-16(7)(v)-23 is a classified cost of service study for the Time-of-Day Rate for Service at Transmission Voltage (Rate TT) class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-24.

A. Schedule FR-16(7)(v)-24 is a classified cost of service study for the Lighting class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. PLEASE DESCRIBE SCHEDULE FR-16(7)(v)-25.

A. Schedule FR-16(7)(v)-25 is a classified cost of service study for the Other – Water Pumping class that shows the allocated costs from Schedules FR-16(7)(v)-3, FR-16(7)(v)-7 and FR-16(7)(v)-11, summarized by the demand, energy, and customer classifications.

Q. HOW DID YOU DEVELOP THE COST OF SERVICE STUDY THAT YOU USED TO ALLOCATE COSTS TO THE DIFFERENT RATE CLASSES?

A. First, I developed various allocation factors based on customer, energy usage, and demand statistics for the test period. Next, I functionalized costs into the specific utility functions, *i.e.,* production, transmission and distribution. I then classified the costs as demand, energy or customer related, or a combination in some instances. Lastly, I allocated the demand, energy and customer related costs to rate classes based on the cost causation guidelines published in the NARUC "Electric

Utility Cost Allocation Manual," my utility company experience, and my knowledge of cost of service studies.

A. Functionalizing Costs

Q. PLEASE EXPLAIN HOW YOU FUNCTIONALIZE COSTS.

A. The production function includes the costs associated with power generation and power purchases and their delivery to the bulk transmission system. The transmission function consists of costs associated with the high voltage system utilized for the bulk transmission of power to and from interconnected utilities to the load centers of the utility's system. The distribution function includes the radial distribution system that connects the transmission system and the ultimate customer.

The Company's accounting records use the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounts functionalize the Company's investment into the primary categories of production (generation), transmission, distribution, and general plant. Similarly, the Company's operating costs are categorized into production, transmission, distribution, customer services, and administrative and general (A&G) functions.

B. Classifying Costs

Q. PLEASE EXPLAIN THE CLASSIFICATION OF COSTS.

A. Next, functionalized costs are grouped according to their cost-causation characteristics. This process is known as classification of costs. Typically these cost-causing characteristics are defined as demand-related, energy-related, or customer-related.

Q. PLEASE DEFINE DEMAND-RELATED COSTS.

A. Demand-related costs are fixed costs incurred regardless of the level of energy sales and have a direct relationship to the kilowatts (kW) of demand that customers place on the various segments of the system. Costs that are classified as demand-related include major portions of the Company's investment and related expenses in its production and transmission facilities and a significant portion of the investment and related expenses of its distribution system. Until the Company has the full ability to bill all customer based on demand (both from a technical and a regulatory perspective), the Company will continue to be required to use fixed charges as a proxy for demand-based billing.

Q. PLEASE DEFINE ENERGY-RELATED COSTS.

A. Energy-related costs are costs incurred that vary in direct relationship to the amount of energy or kilowatt hours (kWh) generated and delivered. These costs are often referred to as variable costs. Fuel is an example of an energy-related cost.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Customer-related costs are costs incurred primarily as a result of the number of customers being served. These fixed costs include items of investment and related expenses in functional categories such as metering, and costs associated with customer accounting and sales. Customer costs do not vary significantly with the customers' volume of usage, but are influenced more by factors such as number of customers.

C. Allocation of Costs

Q. PLEASE EXPLAIN HOW COSTS ARE ALLOCATED TO VARIOUS CUSTOMER CLASSES.

A. The allocation of costs is the process of multiplying the functionalized and classified costs by allocation factors, resulting in costs being assigned to customer classes. Some costs are directly assignable to a single class of customers. Most costs, however, are attributable to more than one type of customer. Costs are allocated to the various customer groups in relationship to how those customers influence the Company to incur the costs. This relationship is referred to as "cost causation." Specific allocation factors are developed that relate to the demand, energy, and customer classifications identified above, in order to accomplish a proper matching of the costs to the customer groups, based on cost causation.

Q. PLEASE DESCRIBE THE ALLOCATION METHODOLOGY YOU USED IN THIS PROCEEDING TO ALLOCATE DEMAND-RELATED COSTS.

A. Each customer class' cost responsibility (*i.e.*, the percentage of the demand related costs assigned to each customer class) is equal to the ratio of their demand in relation to the total demand placed on the system. The cost of service study supporting the Company's proposed rate design in this proceeding allocates production and transmission demand-related costs based upon the 12 monthly coincident peaks (12 CP).

Q. HOW WERE THE DEMAND VALUES DEVELOPED FROM COMPANY CUSTOMER LOAD RESEARCH DATA?

A. kWh sales and load research data for the twelve months ended December 31, 2016, were used to calculate the monthly peak contributions. The calculations of the monthly demands appear on pages 11 through 32 of work paper FR-16(7)(v). The following is an example of how the class group demand was calculated for rate RS for the month of December 2016.

Step 1 – Determine the average demand by dividing the total kWh by the number of hours in the month.

127,529,356 kWh ÷ 744 hours = 171,410 kW

Step 2 – Determine the coincident peak demand by dividing the average demand from Step 1 by the coincident peak load factor supplied by load research.

171,410 kW ÷ 68.2472percent = 251,160 kW

Step 3 – To determine the demand at generation, line losses are added by multiplying the coincident peak demand from step 2 by the loss factor.

251,160 x 1.03363 = 259,607 kW (with losses)

This process was followed for all customer classes for the twelve months of the test year to determine each class' monthly peak coincident with Duke Energy Kentucky's monthly system peak. I used a similar procedure to develop each class's diversified class peak and highest (single) non-coincident peak demands.

Q. PLEASE DESCRIBE HOW THE 12 CP DEMAND ALLOCATOR WAS USED TO ALLOCATE COSTS.

A. The 12 CP demand allocator was used to allocate Production and Transmission capacity related investments and expenses to the customer groups.

Q. PLEASE DESCRIBE THE METHODS USED TO ALLOCATE DISTRIBUTION RELATED COSTS TO THE VARIOUS RATE CLASSES.

A. Several different allocation factors were used to allocate distribution plant to the customer classes. First, distribution plant was grouped by the type of plant such as substations, poles, conductors, *etc.* Then it was determined whether each type is customer- or demand-related factor. Finally, each customer- or demand-related cost was allocated to rate class.

Substations are considered 100 percent demand-related and were allocated using the average class group coincident peak demand ratios for the twelve months ending December 31, 2016. This factor takes into consideration the load diversity by rate group at the distribution substation level.

Poles and conductors are also 100 percent demand.

Transformers were allocated between customer and demand using the minimum size method. Transformers, as well as other distribution plant facilities, are considered to have a customer component because the number of facilities needed on the system, are dependent on the number of customers. The remaining costs are considered to be demand-related. I allocated the demand portion of transformers among the customer classes using the maximum non-coincident peak load ratios. The maximum non-coincident peak demand allocator is appropriate because transformers are sized to meet the maximum demand and are close to the customer so there is little or no load diversity. I then allocated the customer portion of transformers among the customer classes based on the total number of customers.

Services are considered 100 percent customer-related and were allocated based on a weighted-average number of customers (K217). The weighting is based on an engineering analysis that prices various service drop costs based on demands. For example, it is twice as costly for a service drop at 100 kVA versus a service drop at 25 kVA. Customers with an average demand of 100 kVA are weighted at twice the cost of customers with an average demand of 25 kVA.

Other distribution and customer service related costs can be more directly associated with a customer statistics such as the cost of meters (K407), customer charge-offs (K411) and other customer-related studies. As an example, the investment in meters can be directly associated with the costs of metering the various customer groups (K407).

Street lights were directly assigned to the street lighting rate class.

Q. PLEASE DESCRIBE THE MINIMUM SIZE METHOD USED TO ALLOCATE TRANSFORMER COSTS BETWEEN CUSTOMER- AND DEMAND-RELATED COSTS.

A. The minimum size study is shown on Work Paper FR-16(7)(v), page 53. The minimum size method assumes that a minimum size distribution system can be built to serve the minimum load requirements of the customer. For transformers, the study involved determining the minimum size transformer currently installed by Duke Energy Kentucky. In this case, it is a 15 kVa transformer. Duke Energy Kentucky's 2016 average cost of a 15 kVa transformer was $1,568.

I used asset accounting records to determine the number of overhead and pad-mounted transformers installed each year from 1910 to 2016. I then used the

Handy-Whitman Index for Utility Plant Materials (specifically line transformers) to calculate the cost per transformer for each of the years 1910 to 2016, beginning with a 2016 Handy-Whitman index of 883 and 2016 cost of $1,568. For each year, I multiplied the number of transformers by the cost per transformer to get the minimum size cost per year. I summarized each of the years 1910 to 2016 to arrive at the minimum size transformer cost of approximately $18 million. This was classified as customer-related costs. The difference between this customer-related cost and the balance in FERC Line Transformer account 368 is the demand component, resulting in allocation factors of 32.384 percent to customer and 67.616 percent to demand. I allocated all transformer-related cost (plant, accumulated depreciation, Operating and Maintenance (O&M), and depreciation expense) to customer and demand using these factors.

Q. PLEASE DESCRIBE THE METHODOLOGY USED TO ALLOCATE COMMON AND GENERAL PLANT.

A. I functionalized common and general plant based on functional salaries and wages as presented on pages 354-355 of Duke Energy Kentucky's 2016 FERC Form 1 annual report. I then used distribution kW and various weighted O&M expense ratios to allocate each function to customer classes.

Q. PLEASE EXPLAIN HOW YOU ALLOCATED A & G EXPENSES USING THIS METHODOLOGY.

A. I functionalized A&G expenses based on the same functional salaries and wages used for general and common plant. After I functionalized the expenses, I allocated the expenses to rate classes based on the allocation of direct O&M for that function.

For example, A&G expenses functionalized as distribution were allocated to rate classes based on each rate class' allocation of direct distribution O&M.

Q. WHAT ARE THE RATE BASE ADJUSTMENTS THAT YOU IDENTIFY IN THE COST OF SERVICE?

A. While net plant is the largest single component of rate base, there are other items which must be added to or subtracted from rate base. These items include accumulated deferred income taxes (ADIT), miscellaneous deferrals, and working capital which includes materials and supplies and prepayments.

Q. HOW DID YOU ALLOCATE THE ADJUSTMENTS THAT WERE SUBTRACTED FROM RATE BASE?

A. I allocated the subtractive adjustments based on the net plant ratios for each rate class.

Q. HOW DID YOU ALLOCATE ADJUSTMENTS THAT WERE ADDED TO RATE BASE?

A. I used the A&G expense cost factor A315, to allocate the amounts reflected in the Accumulated Deferred Income Tax Account 190.

Q. HOW DID YOU ALLOCATE WORKING CAPITAL?

A. Working capital consists of the following items: fuel inventories, emission allowances, materials and supplies, prepayments, cash, and other miscellaneous items. Fuel Inventories and emission allowances were allocated to rate groups based on K301, class kWh ratios; materials and supplies were allocated using PD29, class net plant ratios; general insurance and excise tax were allocated to rate groups using net plant ratios NP29, Collateral asset was allocated to rate groups based on K301 class kWh ratios.

Cash working capital is equal to 1/8 of non-fuel O&M expense minus the fuel costs and fuel and purchased power adjustment.

Q. HOW DID YOU ALLOCATE DEPRECIATION EXPENSES?

A. I allocated depreciation expenses to rate class based on the functional class net-depreciable plant ratios.

Q. HOW DID YOU ALLOCATE REAL ESTATE AND PROPERTY TAXES?

A. I allocated real estate and property taxes to rate class based on the functional class net plant ratios.

Q. HOW DID YOU ALLOCATE PAYROLL AND HIGHWAY TAXES, THE PSC ASSESSMENT AND OTHER MISCELLANEOUS TAXES?

A. I allocated the PSC Maintenance Taxes to class based on each rate class present revenue ratio. I allocated Payroll, Highway and Other Miscellaneous Taxes to rate class based the class-weighted A&G expense ratio (A315).

Q. HOW DID YOU ALLOCATE FEDERAL AND STATE INCOME TAX ADJUSTMENTS AND DEDUCTIONS?

A. I reviewed each income tax adjustment and deduction to determine the functional cause of the adjustment and deduction, then selected the appropriate allocation factor. For example, an "Other Deductions" item, tax depreciation in excess of book depreciation, was allocated to the rate classes based on the class depreciation expense ratio (DE49).

Q. HOW DID YOU ALLOCATE OTHER OPERATING REVENUES?

A. I evaluated each other operating revenue item to determine the source of the revenue, then selected the appropriate allocation factor. The class ratio of present revenues was the primary allocation factor used to allocate the revenue credits to the respective rate groups.

Q. DID YOU USE ANY OTHER ALLOCATION FACTORS IN THE COST OF SERVICE STUDY?

A. Yes, there are many plant and expense ratios that were developed internally in the cost of service study. The cost of service study lists each item's allocation factor under the column identified as "ALLO."

V. RESULTS OF COST OF SERVICE STUDY

Q. WHAT DO THE RESULTS OF THE COST OF SERVICE STUDY SHOW?

A. Schedule FR-16(7)(v)-14, page 1 of 15, is a summary of the cost of service study that shows the costs allocated to each rate class.

Q. HOW WERE THE RESULTS OF YOUR COST OF SERVICE STUDY USED IN THESE PROCEEDINGS?

A. The results of the fully allocated cost of service study by rate class were supplied to Duke Energy Kentucky witness Bruce Sailers, who used this data to develop the proposed rate design for these proceedings.

VI. DISTRIBUTION OF PROPOSED REVENUE INCREASE

Q. DID THE COST OF SERVICE STUDY SHOW THAT THE INCREASE REQUIRED FOR EACH CUSTOMER CLASS WAS PROPORTIONAL?

A. No. The cost of service study revealed that there are significant differences among the rate classes when comparing the actual return earned by each rate class to the 7.08 percent overall return on capitalization being requested in this case. Put another way, developing rates that generate the amount of revenue that equals the allocated revenue requirement for each rate class will mean much greater increases for some rate classes, in terms of percentage increases, than other classes.

In order to mitigate the rate shock that may come from completely eliminating the subsidy/excess (or rate disparities) among the rate classes, the Company is proposing to use a two-step process to distribute the proposed revenue increase. The first step eliminated 10 percent of the subsidy/excess revenues between customer classes based on present revenues. The second step allocated the rate increase to customer classes based on electric distribution original cost depreciated (OCD) rate base.

Q. THE WATER PUMPING RATE CLASS APPEARS TO BE RECEIVING A VERY LARGE RATE INCREASE. PLEASE EXPLAIN HOW THIS IS BEING HANDLED IN THE PROPOSED RATES.

A. The customers in this class are served under special contracts. The rates for these customers will not change. The proposed rate increase for this class was added to the proposed revenues for Rate DP.

Q. PLEASE EXPLAIN IN GREATER DETAIL THE FIRST STEP THAT ELIMINATES 10 PERCENT OF THE SUBSIDY/EXCESS REVENUES.

A. Again, it is a general tenet of ratemaking that each class should, to the extent practicable, pay the costs of providing service to that class. The elimination of a portion of the subsidy/excess takes into consideration that the Company is not earning the same rate of return on all customer classes. It is unlikely that equal rates of return across all rate classes are achievable; nonetheless, to the extent possible, large variances among the customer classes should be eliminated. A comparison of revenues under present rates and at the retail average rate of return is made and then 10 percent of that amount is added to, or subtracted from, the rate increase to determine the proposed revenues in this proceeding.

Admittedly, this proposal lets a subsidy/excess persist but it will close the gap so that each class is paying rates that more closely reflect their costs of service.

Q. HOW DID THIS RATE DISPARITY ARISE?

A. Rate disparities exist mostly due to the fact that over the years rates have not been set based on the cost to serve customers as determined by a cost of service study. Other factors include: (1) customer mix often changes between rate cases, *i.e.,* residential, for example, may make up more or less of the total today than it did the last time rates were set; (2) different asset classes depreciate at different rates and because different asset classes are allocated differently, long periods between rate cases can shift the relative costs to serve each rate class. Also, regulators may purposely allow subsidy/excesses to persist in the interest of rate gradualism.

Q. WHY DID YOU PROPOSE A TEN PERCENT REDUCTION OF THE SUBSIDY/EXCESS REVENUES IN THESE PROCEEDINGS?

A. The present rate of returns by class shown on Work Paper FR-16(7)(v), page 1, indicate that there is a significant difference in those returns. In order to ensure that each rate class pays the actual cost to serve that class, and move each class to the average rate of return, 100 percent of the subsidy/excess would need to be eliminated. However, given the wide disparity among rate classes, complete elimination of the subsidy excess would cause a dramatic swing in rate impacts between and among various rate classes. By proposing to eliminate only ten percent of the subsidy/excess, the Company is choosing to invoke the rate making principle of gradualism so to mitigate the volatility of 100 percent subsidy/excess elimination.

VII. <u>CONCLUSION</u>

Q. WERE ATTACHMENTS JEZ-1 AND JEZ-2, SCHEDULES B-7, B-7.1, B-7.2, D-3, D-4 AND D-5, AS WELL AS, FR 16(7)(v), AND WORKPAPER FR 16(7)(v), 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, James E. Ziolkowski, Director, Rates & Regulatory Planning, 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.

James E. Ziolkowski

James E. Ziolkowski Affiant

Subscribed and sworn to before me by James E. Ziolkowski 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, INC.
ELECTRIC COST OF SERVICE STUDY
CASE NO: 2017-00321
ALLOCATION FACTORS FOR COST OF SERVICE STUDY

LINE NO.	RATE GROUP	12 CP DEMAND RATIO %	AVG & EXCESS RATIO %	DIFFERENCE %	S/NS RATIO %	DIFFERENCE %
1		A	B	C = B - A	D	E = D - A
2	**Retail:**					
3	Residential	41.780%	41.043%	-0.737%	41.764%	-0.016%
4	Dist Secondary - DS	29.423%	28.228%	-1.195%	29.561%	0.138%
5	Dist Secondary - GS-FL	0.136%	0.133%	-0.003%	0.135%	-0.001%
6	Dist Secondary - EH	0.479%	0.620%	0.141%	0.443%	-0.036%
7	Dist Secondary - SP	0.007%	0.007%	0.000%	0.007%	0.000%
8	Dist Secondary - DT	13.928%	14.529%	0.601%	13.915%	-0.013%
9	Dist Primary - DT	9.544%	10.107%	0.563%	9.523%	-0.021%
10	Dist Primary - DP	0.348%	0.334%	-0.014%	0.345%	-0.003%
11	Transmission	4.208%	4.379%	0.171%	4.171%	-0.037%
12	Lighting	0.143%	0.616%	0.473%	0.132%	-0.011%
13	Other	0.004%	0.004%	0.000%	0.004%	0.000%
14	Total Retail	100.000%	100.000%	0.000%	100.000%	0.000%

DUKE ENERGY KENTUCKY, INC.
ELECTRIC COST OF SERVICE STUDY
CASE NO: 2017-00321

K201 Allocator Using 12 CP

Line No.	Rate Class	Jurisdictional Electric Capitalization (A)	Present Revenues (B)	Net Operating Income (C)	Present ROR (D)	Present Revenues At Average ROR (E)	Inter Class Subsidization Overcollected (Undercollected) (F)	Inter Class Subsidization times 10.00% (G)	Rate Increase (Allocated to class based on Rate Base) (H)	Proposed Revenues 90.00% Interclass Subsidization (I)	Proposed Percent Increase (J)	ROR At Proposed Rates (K)	Proposed Increase Less (Subsidy) Excess (L)
		FR-16(7)(v)-14, page1	FR-16(7)(v)-14, page1	Work Paper FR-16(7)(v), Page 2	(C) / (A)	(C))/(1-CompositeTaxRate))	(B) - (E)	(F) * 10.00%	(H) Line 5 * ((A) / (A) Line 5)	(B) - (G) + (H)	((H) - (G)) / (B)	((((H) - (G))*(1-CompositeTaxRate)+ (C)) / (A)	(H) - (G)
1	Rate RS	$ 317,425,709	$ 120,391,018	$ 3,124,836	0.9844%	$ 129,927,706	$ (9,536,688)	$ (953,667)	$ 21,901,356	$ 143,246,041	18.984%	5.414347%	$ 22,855,023
2	Rate DS	200,757,632	89,967,454	11,187,968	5.5729%	81,026,932	8,940,522	894,052	13,851,623	102,925,025	14.403%	9.543943%	12,957,571
3	Rate GS-FL	932,077	589,997	129,751	13.9206%	422,024	167,973	16,797	64,310	637,510	8.053%	17.056944%	47,513
4	Rate EH	3,472,840	623,628	(418,272)	-12.0441%	1,463,366	(839,738)	(83,974)	239,631	947,233	51.891%	-6.311026%	323,605
5	Rate SP	57,138	28,730	5,292	9.2618%	22,760	5,970	597	3,940	32,073	11.637%	12.861866%	3,343
6	Rate DT - Secondary	91,880,872	45,903,624	3,817,007	4.1543%	43,930,272	1,973,352	197,335	6,339,478	52,045,767	13.381%	8.267225%	6,142,143
7	Rate DT-Primary	62,892,854	30,722,085	1,348,318	2.1438%	31,426,461	(704,376)	(70,438)	4,339,389	35,131,912	14.354%	6.457795%	4,409,827
8	Rate DP	2,273,698	926,746	(1,938)	-0.0852%	1,034,586	(107,840)	(10,784)	156,884	1,094,414	18.092%	4.451814%	167,668
9	Rate TT	21,736,943	13,220,511	825,853	3.7993%	12,879,079	341,432	34,143	1,499,763	14,686,131	11.086%	7.947690%	1,465,620
10	Lighting	3,107,084	1,889,364	36,900	1.1876%	1,972,452	(83,088)	(8,309)	214,384	2,112,057	11.787%	5.597312%	222,693
11	Other - Water Pumping	514,293	7,414	(82,345)	-16.0113%	164,933	(157,519)	(15,752)	35,463	58,629	690.789%	-9.884365%	51,215
12													
13	Total	$ 705,051,140	$ 304,270,571	$ 19,973,370	2.8329%	$ 304,270,571	$ -	$ -	$ 48,646,222	$ 352,916,793	15.988%	7.077963%	$ 48,646,222

K201 Allocator Using Average and Excess Method

Line No.	Rate Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Rate RS	$ 314,169,253	$ 120,391,018	$ 3,170,365	1.0091%	$ 129,703,764	$ (9,312,746)	$ (931,274)	$ 21,676,659	$ 142,998,951	18.779%	5.436572%	$ 22,607,933
2	Rate DS	195,467,534	89,967,454	11,262,533	5.7618%	80,662,160	9,305,294	930,529	13,486,630	102,523,555	13.956%	9.714018%	12,556,101
3	Rate GS-FL	918,929	589,997	129,997	14.1466%	421,019	168,978	16,898	63,386	636,485	7.879%	17.259119%	46,488
4	Rate EH	4,095,205	623,628	(426,967)	-10.4260%	1,506,155	(882,527)	(88,253)	282,537	994,418	59.457%	-4.855337%	370,790
5	Rate SP	57,138	28,730	5,293	9.2635%	22,758	5,972	597	3,940	32,073	11.637%	12.863616%	3,343
6	Rate DT - Secondary	94,536,877	45,903,624	3,779,629	3.9980%	44,113,318	1,790,306	179,031	6,522,729	52,247,322	13.820%	8.126594%	6,343,698
7	Rate DT-Primary	65,382,312	30,722,085	1,313,237	2.0086%	31,598,104	(876,019)	(87,602)	4,511,159	35,320,846	14.969%	6.336045%	4,598,761
8	Rate DP	2,212,339	926,746	(1,141)	-0.0516%	1,030,466	(103,720)	(10,372)	152,652	1,089,770	17.591%	4.482153%	163,024
9	Rate TT	22,490,792	13,220,511	815,147	3.6244%	12,931,191	289,320	28,932	1,551,814	14,743,393	11.519%	7.790343%	1,522,882
10	Lighting	5,202,085	1,889,364	7,589	0.1459%	2,116,555	(227,191)	(22,719)	358,912	2,270,995	20.199%	4.659473%	381,631
11	Other - Water Pumping	518,676	7,414	(82,312)	-15.8696%	165,081	(157,667)	(15,767)	35,804	58,985	695.584%	-9.752303%	51,571
12													
13	Total	$ 705,051,140	$ 304,270,571	$ 19,973,370	2.8329%	$ 304,270,571	$ -	$ -	$ 48,646,222	$ 352,916,793	15.988%	7.077963%	$ 48,646,222

K201 Allocator Using Summer Non-Summer Method

Line No.	Rate Class	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Rate RS	$ 317,368,732	$ 120,391,018	$ 3,125,707	0.9849%	$ 129,923,665	$ (9,532,647)	$ (953,265)	$ 21,897,416	$ 143,241,699	18.980%	5.414752%	$ 22,850,681
2	Rate DS	201,366,848	89,967,454	11,179,462	5.5518%	81,068,808	8,898,646	889,865	13,893,653	102,971,242	14.454%	9.524966%	13,003,788
3	Rate GS-FL	927,694	589,997	129,815	13.9933%	421,719	168,278	16,828	64,018	637,187	7.998%	17.123017%	47,190
4	Rate EH	3,310,675	623,628	(415,920)	-12.5630%	1,452,076	(828,448)	(82,845)	228,443	934,916	49.916%	-6.778024%	311,288
5	Rate SP	57,138	28,730	5,293	9.2635%	22,758	5,972	597	3,940	32,073	11.637%	12.863616%	3,343
6	Rate DT - Secondary	91,819,512	45,903,624	3,817,897	4.1580%	43,926,001	1,977,623	197,762	6,335,246	52,041,108	13.370%	8.270597%	6,137,484
7	Rate DT-Primary	62,796,431	30,722,085	1,349,598	2.1492%	31,419,941	(697,856)	(69,786)	4,332,724	35,124,595	14.330%	6.462580%	4,402,510
8	Rate DP	2,260,550	926,746	(1,806)	-0.0799%	1,033,767	(107,021)	(10,702)	155,960	1,093,408	17.984%	4.456159%	166,662
9	Rate TT	21,570,394	13,220,511	828,104	3.8391%	12,867,752	352,759	35,276	1,488,283	14,673,518	10.991%	7.983513%	1,453,007
10	Lighting	3,058,873	1,889,364	37,567	1.2281%	1,969,148	(79,784)	(7,978)	211,076	2,108,418	11.594%	5.634144%	219,054
11	Other - Water Pumping	514,293	7,414	(82,347)	-16.0117%	164,936	(157,522)	(15,752)	35,463	58,629	690.789%	-9.884754%	51,215
12													
13	Total	$ 705,051,140	$ 304,270,571	$ 19,973,370	2.8329%	$ 304,270,571	$ -	$ -	$ 48,646,222	$ 352,916,793	15.988%	7.077963%	$ 48,646,222