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 1

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Forecasted Test Period Filing Requirements
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1	1	KRS 278.180	30 days' notice of rates to PSC.	James P. Henning
1	2	807 KAR 5:001 Section 7(1)	The original and 10 copies of application plus copy for anyone named as interested party.	James P. Henning
1	3	807 KAR 5:001 Section 12(2)	(a) Amount and kinds of stock authorized. (b) Amount and kinds of stock issued and outstanding. (c) Terms of preference of preferred stock whether cumulative or participating, or on dividends or assets or otherwise. (d) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee, or trustee, amount of indebtedness authorized to be secured thereby, and the amount of indebtedness actually secured, together with any sinking fund provisions. (e) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving date of issue, face value, rate of interest, date of maturity and how secured, together with amount of interest paid thereon during the last fiscal year. (f) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year. (g) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year. (h) Rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.	John L. Sullivan, III
1	4	807 KAR 5:001 Section 12(2)(i)	Detailed income statement and balance sheet.	David L. Doss
1	5	807 KAR 5:001 Section 14(1)	Full name, mailing address, and electronic mail address of applicant and reference to the particular provision of law requiring PSC approval.	James P. Henning

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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

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR KRS 278.180

KRS 278.180

Description of Filing Requirement:

Provide thirty (30) days' notice of rate change to Kentucky Public Service Commission.

Response:

See attached.

Sponsoring Witness: James P. Henning

DUKE ENERGY.

James P. Henning
President
Duke Energy Kentucky

139 E. 4th Street
Room 1409-M
Cincinnati, OH 45202

513.287.4078
jim.henning@duke-energy.com

VIA OVERNIGHT MAIL

August 1, 2017

RECEIVED

AUG 02 2017

PUBLIC SERVICE
COMMISSION

Mr. John Lyons
Interim Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, Kentucky 40602-0615

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.

Dear Mr. Lyons:

Duke Energy Kentucky, Inc ("Duke Energy Kentucky" or the "Company") notifies the Commission that it will file a general electric rate case in four weeks or reasonably soon thereafter.[1] Duke Energy Kentucky will use a forward-looking test period for this case.

Additionally, as part of the new tariffs included in the Company's application, Duke Energy Kentucky seeks to establish an environmental surcharge mechanism and environmental compliance plan in accordance with KRS 278.183 as part of this proceeding.

Duke Energy Kentucky has contemporaneously filed a Notice of Election of use of Electronic Filing Procedures for this proceeding. Please assign this matter a case number and style and advise us of same so that it can be incorporated in the application and supporting testimony before filing with the Commission.

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[1] Duke Energy Kentucky provides this notice pursuant to Commission regulation 807 KAR 5:001 Section 16(2).

Duke Energy Kentucky is providing a copy of this notice to the Attorney General's Utility Intervention and Rate Division. We will work diligently with the Commission and our other stakeholders to seek a constructive resolution. Thank you for your consideration.

Sincerely,

James P. Henning

JPS/ ROD

cc: Chairman Michael Schmitt (via overnight mail)
Vice Chairman Robert Cicero (via overnight mail)
Commissioner Dr. Talina Mathews (via overnight mail)
Hon. Andrew Beshear (via overnight mail)
Hon. Rebecca Goodman (via overnight mail)

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 7(1)

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807 KAR 5:001, SECTION 7(1)

Description of Filing Requirement:

Unless the Commission orders otherwise or the electronic filing procedures established in Section 8 of this administrative regulation are used, if a paper is filed with the commission, an original unbound and ten (10) additional copies in paper medium shall be filed.

Response:

In accordance with the Commission's Order dated August 2, 2017, Paragraph 3, the original and six (6) copies of the paper Application will be provided.

Witness Responsible: James P. Henning

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807 KAR 5:001, SECTIONS 12(2)(a) through 12(2)(h)

Description of Filing Requirements:

Section 12(2)(a)

- Amount and kinds of stock authorized.

Section 12(2)(b)

- Amount and kinds of stock issued and outstanding.

Section 12(2)(c)

- Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise.

Section 12(2)(d)

- A brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with sinking fund provisions, if applicable.

Section 12(2)(e)

- The amount of bonds authorized and amount issued, giving the name of the public utility that issued the same, describing each class separately and giving the date of issue, face value, rate of interest, date of maturity, and how secured, together with amount of interest paid during the last fiscal year.

Section 12(2)(f)

- Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid during the last fiscal year.

Section 12(2)(g)

- Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of a portion of the indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid during the last fiscal year.

Section 12(2)(h)

- The rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.

Response:

See attached.

Sponsoring Witness: John L. Sullivan, III

FINANCIAL EXHIBIT

(1) Section 12(2)(a) Amount and kinds of stock authorized.

1,000,000 shares of Capital Stock $15 par value amounting to $15,000,000 par value.

(2) Section 12(2)(b) Amount and kinds of stock issued and outstanding.

585,333 shares of Capital Stock $15 par value amounting to $8,779,995 total par value. Total Capital Stock and Additional Paid-in Capital as of June 30, 2017:

Capital Stock and Additional Paid-in Capital
As of June 30, 2017
($ per 1,000)

Capital Stock	$8,780
Premiums thereon	18,839
Total Capital Contributions from Parent (since 2006)	8,594
Contribution from Parent Company for Purchase of Generation Assets	140,061
Total Capital Stock and Additional Paid-in-Capital	$176,274

(3) Section 12(2)(c) Terms of preference or preferred stock, cumulative or participating, or on dividends or assets or otherwise.

There is no preferred stock authorized, issued or outstanding.

(4) Section 12(2)(d) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name or mortgagee, or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with any sinking fund provision.

Duke Energy Kentucky does not have any liabilities secured by a mortgage.

(5) **Section 12(2)(e) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving the date of issue, face value, rate of interest, date of maturity and how secured, together with the amount of interest paid thereon during the last fiscal year.**

The Company has four outstanding issues of unsecured senior debentures issued under an Indenture dated December 1, 2004, between itself and Deutsche Bank Trust Company Americas, as Trustee, as supplemented by three Supplemental Indentures. The Indenture allows the Company to issue debt securities in an unlimited amount from time to time. The Debentures issued and outstanding under the Indenture are the following:

Supplemental Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2016
1st Supplemental	3/7/2006	50,000,000	0	5.750%	3/10/2016	1,437,500
1st Supplemental	3/7/2006	65,000,000	65,000,000	6.200%	3/10/2036	4,030,000
2nd Supplemental	9/22/2009	100,000,000	100,000,000	4.650%	10/1/2019	4,650,000
3rd Supplemental	1/5/2016	45,000,000	45,000,000	3.420%	1/15/2026	812,250
3rd Supplemental	1/5/2016	50,000,000	50,000,000	4.450%	1/15/2046	1,174,306
			260,000,000			12,104,056

(6) **Section 12(2)(f) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last fiscal year.**

Not applicable.

(7) **Section 12(2)(g) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.**

The Company has two series of Pollution Control Revenue Refunding Bonds issued under a Trust Indenture dated as of August 1, 2006 and a Trust Indenture dated as of December 1, 2008, between the County of Boone, Kentucky and Deutsche Bank National Trust Company as Trustee. The Company's obligation to make payments equal to debt service on the Bonds is evidenced by a Loan Agreement dated as of August 1, 2006 and December 1, 2008 between the County of Boone, Kentucky and Duke Energy Kentucky. The Bonds issued under the Indentures are as follows:

Indenture	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity	Interest Paid Year 2016
Series 2010	11/24/2010	26,720,000	26,720,000	3.86%[1]	8/1/2027	1,031,392
Series 2008A	12/01/2011	50,000,000	50,000,000	1.26% [2]	8/1/2027	629,688
			76,720,000			1,661,080

[1] The bonds were issued at a variable-rate and were swapped to a fixed rate of 3.86% for the life of the debt. The average floating-rate of interest on the bonds for 2016 was 0.41%.

[2] The interest rate represents the average floating-rate of interest on the bonds for 2016. The interest rate on the bonds resets on the first day of every month based on 75% of the sum of one month and spread of 1.25%.

The Company has issued and has outstanding as of June 30, 2017 the following capital leases:

Series	Date of Issue	Principal Amount Authorized and Issued	Principal Amount Outstanding	Rate of Interest	Date of Maturity
Erlanger	12/30/2006	2,100,000	718,288	8.634	09/30/2020
2009	04/21/2009	3,429,432	771,240	4.821	04/21/2018
2010	06/18/2010	955,061	324,045	3.330	06/18/2019
		9,551,448	1,813,573		

The Company also has $49,544,000 of money pool borrowings outstanding as of June 30, 2017, $25,000,000 of which is classified as Long-Term Debt payable to affiliated companies. This obligation, which is short-term by nature, is classified as long-term due to Duke Energy Kentucky's intent and ability to utilize such borrowings as long-term financing.

(8) **Section 12(2)(h) Rate and amount of dividends paid during the last five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year.**

DIVIDENDS PER SHARE

Year Ending	Per Share	Total	No. of Shares	Par Value of Stock
December 31, 2012	17.08	10,000,000	585,333	8,779,995
December 31, 2013	68.34	40,001,000	585,333	8,779,995
December 31, 2014	0.00	0	585,333	8,779,995
December 31, 2015	93.96	55,000,000	585,333	8,779,995
December 31, 2016	17.08	10,000,000	585,333	8,779,995

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 12(2)(i)

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807 KAR 5:001, SECTION 12(2)(i)

Description of Filing Requirement:

A detailed income statement and balance sheet.

Response:

See attached.

Sponsoring Witness: David L. Doss, Jr.

DUKE ENERGY KENTUCKY, INC.
CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)
(In thousands)

	Twelve Months Ended June 30 2017
Operating Revenues	
Electric	344,622
Gas	91,756
Total operating revenues	436,378
Operating Expenses	
Fuel used in electric generation and purchased power	126,585
Natural gas purchased	36,672
Operation, maintenance and other	144,380
Depreciation and amortization	44,551
Property and other taxes	14,362
Goodwill and other impairment charges	1,190
Total operating expenses	367,740
Gains on Sales of Other Assets and Other, net	19
Operating Income	68,657
Other Income and Expenses, net	3,316
Interest Expense	13,634
Income Before Income Taxes	58,339
Income Tax Expense	19,784
Income From Continuing Operations	38,555
Income From Discontinued Operations, net of tax	-
Net Income	38,555

DUKE ENERGY KENTUCKY, INC.
Condensed Balance Sheets
(Unaudited)

(in thousands, except share amounts)	June 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and Cash Equivalents	**4,461**	6,534
Receivables (net of allowancefor doubtful accounts of $216 at June 30, 2017 and $141 at December 31, 2016)	**2,509**	1,663
Receivables from affiliated companies	**9,807**	22,762
Inventory	**44,028**	49,037
Regulatory Assets	**4,458**	7,623
Other	**14,659**	19,272
Total Current Assets	**79,922**	106,891
Property, Plant and Equipment		
Cost	**2,161,657**	2,116,219
Less Accumulated Depreciation and Amortization	**(956,545)**	(948,144)
Net Property Plant and Equipment	**1,205,112**	1,168,075
Other Noncurrent Assets		
Regulatory Assets	**108,044**	92,462
Other	**3,152**	2,720
Total Other Noncurrent Assets	**111,196**	95,182
Total Assets	**1,396,230**	1,370,148
LIABILITIES AND COMMON STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable	**28,759**	31,636
Accounts payable to affiliated companies	**9,467**	12,573
Notes payable to affiliated companies	**24,544**	19,656
Taxes Accrued	**7,140**	14,082
Interest Accrued	**4,276**	4,230
Current Maturities of Long-Term Debt	**504**	686
Regulatory Liabilities	**3,700**	12,173
Other	**18,786**	18,561
Total Current Liabilities	**97,176**	113,597
Long-Term Debt	**336,280**	336,360
Notes payable to affiliated companies	**25,000**	25,000
Other Noncurrent Liabilities		
Deferred Income Taxes	**336,035**	311,636
Asset Retirement Obligations	**51,112**	52,822
Regulatory Liabilities	**53,983**	51,878
Accrued Pension and Other Post-Retirement Benefit Costs	**14,974**	14,975
Investment Tax Credit	**634**	686
Other	**25,874**	26,179
Total Other Noncurrent Liabilities	**482,612**	458,176
Commitments and Contingencies		
Equity		
Common Stock, $15.00 par value, 1,000,000 shares authorized and 585,333 shares outstanding at June 30, 2017 and December 31, 2016	**8,780**	8,780
Additional Paid in Capital	**167,494**	167,494
Retained Earnings	**278,888**	260,741
Total Duke Energy Corporation Stockholders' Equity	**455,162**	437,015
Noncontrolling Interests	**-**	-
Total Liabilities and Equity	**1,396,230**	1,370,148

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(1)

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807 KAR 5:001, SECTION 14(1)

Description of Filing Requirement:

Each application shall state the full name, mailing address, and electronic mail address of the applicant, and shall contain fully the facts on which the application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing for the information.

Response:

See application submitted in this proceeding.

Sponsoring Witness: James P. Henning

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(2)

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807 KAR 5:001, SECTION 14(2)

Description of Filing Requirement:

If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.

Response:

See attached.

Sponsoring Witness: James P. Henning

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes Secretary of State P. O. Box 718 Frankfort, KY 40602-0718 (502) 564-3490 http://www.sos.ky.gov	**Certificate of Existence**

Authentication number: 192031
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

DUKE ENERGY KENTUCKY, INC.

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is March 20, 1901 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 1st day of August, 2017, in the 226th year of the Commonwealth.

Alison Lundergan Grimes

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
192031/0052929

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(3)

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807 KAR 5:001, SECTION 14(3)

Description of Filing Requirement:

If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness: James P. Henning

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 14(4)

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807 KAR 5:001, SECTION 14(4)

Description of Filing Requirement:

If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.

Response:

Duke Energy Kentucky is a corporation; therefore, this requirement does not apply.

Sponsoring Witness: James P. Henning

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(1)

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807 KAR 5:001, SECTION 16(1)(b)(1)

Description of Filing Requirement:

Statement of the reason the adjustment is required.

Response:

1) Duke Energy Kentucky's current base rates reflect its cost of service as prepared in 2006, which is no longer sufficient to enable the Company to furnish adequate, efficient and reasonable service and to have the opportunity to earn a fair rate of return on its investments.

2) Duke Energy Kentucky needs to adjust its current costs of service to reflect its capital investments and operations and maintenance of its electric generation, transmission and distribution that have changed since its 2006 case.

   a. The thirteen-month average of gross plant in this forecasted test period for this case is $1.731 billion, as compared to approximately $1.122 billion included in the 2006 rate case. This equates to an increase of approximately $600 million in gross utility plant since the 2006 rate case. The depreciation, property taxes, and return on this increased investment are the primary drivers of the need for new rates.

3) Other drivers include:

   a. Near stagnant load growth;

b. Need to commence recovery of authorized deferrals (*e.g.*, storm costs, environmental compliance, East Bend Acquisition, *etc.*);

c. Implementation of new recovery mechanisms including environmental compliance, distribution capital, and transmission reconciliation.

Please refer to the direct testimony of Duke Energy Kentucky witnesses James P. Henning and William Don Wathen, Jr.

Sponsoring Witness: James P. Henning / William Don Wathen, Jr.

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(2)

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807 KAR 5:001, SECTION 16(1)(b)(2)

Description of Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that a certificate is not necessary.

Response:

Duke Energy Kentucky transacts business using the following assumed name: Duke Energy.

A certified copy of the Company's certificate of assumed name is attached.

Sponsoring Witness: James P. Henning

COMMONWEALTH OF KENTUCKY

Alison Lundergan Grimes
Secretary of State

Certificate

I, Alison Lundergan Grimes, Secretary of State for the Commonwealth of Kentucky, do hereby certify that the foregoing writing has been carefully compared by me with the original thereof, now in my official custody as Secretary of State and remaining on file in my office, and found to be a true and correct copy of

RENEWAL CERTIFICATE OF ASSUMED NAME OF

DUKE ENERGY ADOPTED BY DUKE ENERGY KENTUCKY, INC. FILED FEBRUARY 24, 2016.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 1st day of August, 2017.

Alison Lundergan Grimes

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
rpacheco/0052929 - Certificate ID: 192043

C227
0052929.04
Alison Lundergan Grimes
KY Secretary of State
Received and Filed
2/24/2016 11:47:22 AM
Fee receipt: $20.00

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes Secretary of State P. O. Box 718 Frankfort, KY 40602-0718 (502) 564-3490 http://www.sos.ky.gov	**Renewal Certificate of Assumed Name**	**REN**

This certifies that the assumed name of

DUKE ENERGY

is hereby renewed by

DUKE ENERGY KENTUCKY, INC.

a business entity organized and existing in the state of Kentucky.

Signatures

Signature	Nancy M. Wright
Title	Assistant Corporate Secretary
Date	2/24/2016 11:47:22 AM

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(3)

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807 KAR 5:001, SECTION 16(1)(b)(3)

Description of Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed.

Response:

The proposed tariffs are at Schedule L-1.

Sponsoring Witness: Bruce L. Sailers

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(4)

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807 KAR 5:001, SECTION 16(1)(b)(4)

Description of Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing:

a. The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or

b. A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions.

Response:

See Schedules L-2.1 and L-2.2.

Sponsoring Witness: Bruce L. Sailers

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(1)(b)(5)

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807 KAR 5:001, SECTION 16(1)(b)(5)

Description of Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.

Response:

See attached.

Sponsoring Witness: James P. Henning

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of an Environmental Compliance Plan and Surcharge Mechanism; 3) Approval of New Tariffs; 4) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 5) All Other Required Approvals and Relief.	)	Case No. 2017-000321

CERTIFICATE OF NOTICE

Pursuant to the Kentucky Public Service Commission's Regulation 807 KAR 5:001, Section 16(1)(b)(5), I hereby certify that I am James P. Henning, President of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), a utility furnishing retail electric and gas service within the Commonwealth of Kentucky, which, on the 1st day of September, 2017, filed an application with the Kentucky Public Service Commission for the approval of an adjustment of the electric rates, terms, conditions, and tariffs of Duke Energy Kentucky, and that notice to the public of the issuing of the same is being given in all respects as required by 807 KAR 5:001, Section 17 and 807 KAR 5:001, Sections 8(2)(c) and 9(2), as follows:

On the 1st day of September, 2017, the notice to the public was delivered for exhibition and public inspection at 4580 Olympic Boulevard, Erlanger, Kentucky 41018 and the same will be kept open to public inspection at said office in conformity with the requirements of 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(1)(a).

I further certify that more than twenty (20) customers will be affected by said change by way of an increase in their rates or charges, and that on the 18th day of August, 2017, there was delivered to the Kentucky Press Association, an agency that acts on behalf of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, for publication therein once a week for three consecutive weeks beginning on August 28, 2017, a notice of the filing of Duke Energy Kentucky's application, including its proposed rates, a copy of said notice being attached hereto as Exhibit A, and a list of newspapers of general circulation throughout the Commonwealth of Kentucky in which customers affected reside, a copy of said list being attached hereto as Exhibit B. A certificate of publication of said notice will be furnished to the Kentucky Public Service Commission upon completion of same pursuant to 807 KAR 5:001, Section 17(3)(b).

Also beginning on September 1, 2017, Duke Energy Kentucky posted on its website a complete copy of the Company's application and a hyperlink to the location on the Kentucky Public Service Commission's website where the case documents and tariff filings are available.

Given under my hand this 1st day of September, 2017.

James P. Henning
President, Duke Energy Kentucky, Inc.
139 E. 4th Street
Cincinnati, Ohio 45202

Subscribed and sworn to before me, a Notary Public, in and before said County and State, this 1st day of September, 2017.

E. Minna Rolfes-Adkins
Notary Public

My Commission expires: July 8, 2022

NOTARY PUBLIC ★ STATE OF OHIO ★

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

NOTICE

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

The proposed electric rates are applicable to the following communities:

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

DUKE ENERGY KENTUCKY CURRENT AND PROPOSED ELECTRIC RATES

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

Current Rate

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

Proposed Rate

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

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

Current Rate

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

Proposed Rate

Customer Charge per month	
Single Phase Service	\$ 17.14 per month
Three Phase Service	\$34.28 per month
Demand Charge	
First 15 kilowatts	\$ 0.00 per kW

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

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

Current Rate

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

Proposed Rate

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

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

Current Rate

A. Winter Period

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

Proposed Rate

A. Winter Period

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

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

Current Rate

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

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

Proposed Rate

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

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

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

Current Rate

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

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

Minimum: $3.00 per Fixed Load Location per month.

Proposed Rate

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

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

Minimum: $3.14 per Fixed Load Location per month.

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

Current Rate

Customer Charge per month	
Primary Voltage Service (12.5 or 34.5 kV)	$100.00 per month
Demand Charge	
All kilowatt	$ 7.08 per kW
Energy Charge	
First 300 kWh/kW	5.1068¢ per kWh
Additional kWh	4.3198¢ per kWh

Proposed Rate

Customer Charge per month	
Primary Voltage Service (12.5 or 34.5 kV)	$118.78 per month
Demand Charge	
All kilowatts	$ 8.40 per kW
Energy Charge	
First 300 kWh	6.0595¢ per kWh
Additional kWh	5.1267¢ per kWh

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

Current Rate

Customer Charge per month	$500.00 per month
Demand Charge	
Summer	
On Peak kW	$ 7.60 per kW
Off Peak kW	$ 1.15 per kW
Winter	
On Peak kW	$ 6.24 per kW
Off Peak kW	$ 1.15 per kW
Energy Charge	
All kWh	4.2648¢ per kWh

Proposed Rate

Customer Charge per month	$500.00 per month
Demand Charge	
Summer	
On Peak kW	$ 8.46 per kW
Off Peak kW	$ 1.28 per kW
Winter	
On Peak kW	$ 6.95 per kW
Off Peak kW	$ 1.28 per kW
Energy Charge	
Summer	
On Peak kWh	5.4454¢ per kWh
Off Peak kWh	4.4594¢ per kWh
Winter	
On Peak kWh	5.1983¢ per kWh
Off Peak kWh	4.4594¢ per kWh

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

Current Rate

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

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

3. Monthly Transmission Reservation Charge

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

4. Monthly Ancillary Services Reservation Charge

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

Proposed Rate

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

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

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

Current Rate

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

Energy Delivery Charge
Charge For Each kW Per Hour:

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

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

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

Proposed Rate

CANCELLED & WITHDRAWN

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

Current Rate

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

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

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

UNDERGROUND DISTRIBUTION AREA Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$7.24
7,000 lumen (Open Refractor)	175	0.205	853	$ 5.94
10,000 lumen	250	0.292	1,215	$ 8.36
21,000 lumen	400	0.460	1,914	$ 11.25
Metal Halide				
14,000 lumen	175	0.210	874	$ 7.24
20,500 lumen	250	0.292	1,215	$ 8.36
36,000 lumen	250	0.292	1,215	$11.25
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 7.87
9,500 lumen (Open Refractor)	100	0.117	487	$ 5.99
16,000 lumen	150	0.171	711	$ 8.55
22,000 lumen	200	0.228	948	$ 11.13
50,000 lumen	400	0.471	1,959	$ 14.95
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$ 7.48

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

POLE CHARGES

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

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

Proposed Rate

OVERHEAD DISTRIBUTION AREA Fixture Description	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.193	803	$ 7.96
7,000 lumen (Open Refractor)	175	0.205	853	$ 6.65
10,000 lumen	250	0.275	1,144	$ 9.19
21,000 lumen	400	0.430	1,789	$ 12.30

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

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

Spans of Secondary Wiring:

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

UNDERGROUND DISTRIBUTION AREA	Lamp Watts	kW/Unit	Annual kWh	Rate/Unit
Fixture Description				
Standard Fixture (Cobra Head)				
Mercury Vapor				
7,000 lumen	175	0.210	874	$ 8.10
7,000 lumen (Open Refractor)	175	0.205	853	$ 6.65
10,000 lumen	250	0.292	1,215	$ 9.35
21,000 lumen	400	0.460	1,914	$ 12.59
Metal Halide				
14,000 lumen	175	0.193	803	$ 8.10
20,500 lumen	250	0.275	1,144	$ 9.35
36,000 lumen	400	0.430	1,789	$ 12.59
Sodium Vapor				
9,500 lumen	100	0.117	487	$ 8.81
9,500 lumen (Open Refractor)	100	0.117	487	$ 6.70
16,000 lumen	150	0.171	711	$ 9.57
22,000 lumen	200	0.228	948	$ 12.45
50,000 lumen	400	0.471	1,959	$ 16.73
Decorative Fixtures				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$ 8.37
7,000 lumen (Holophane)	175	0.210	874	$ 10.52
7,000 lumen (Gas Replica)	175	0.210	874	$ 24.04
7,000 lumen (Granville)	175	0.210	874	$ 8.46
7,000 lumen (Aspen)	175	0.210	874	$15.23
Metal Halide				
14,000 lumen (Traditionaire)	175	0.205	853	$ 8.37
14,000 lumen (Granville Acorn)	175	0.210	874	$ 15.23
14,000 lumen (Gas Replica)	175	0.210	874	$ 24.13
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$ 12.23
9,500 lumen (Holophane)	100	0.128	532	$ 13.25
9,500 lumen (Rectilinear)	100	0.117	487	$ 9.88

9,500 lumen (Gas Replica)	100	0.128	532	$ 24.91
9,500 lumen (Aspen)	100	0.128	532	$ 15.43
22,000 lumen (Rectilinear)	200	0.246	1,023	$ 13.59
50,000 lumen (Rectilinear)	400	0.471	1,959	$ 17.97
50,000 lumen (Setback)	400	0.471	1,959	$ 26.62

POLE CHARGES

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

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

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

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

Current Rate
Where the Company supplies energy only, all kilowatt-hours shall be billed at 3.8066 cents per kilowatt hour;
Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 2.1078 cents per kilowatt-hour.
Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 5.9145 cents per kilowatt-hour.

Proposed Rate
Where the Company supplies energy only, all kilowatt-hours shall be billed at 4.2590 cents per kilowatt-hour;
Where the Company supplies energy from a separately metered source and the Company has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 2.3583 cents per kilowatt-hour.
Where the Company supplies energy and has agreed to provide limited maintenance for traffic signal equipment, all kilowatt-hours shall be billed at 6.6174 cents per kilowatt-hour.

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

Current Rate
All kWh 3.7481 ¢ per kWh
Proposed Rate
All kWh 4.1936¢ per kWh

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

Current Rate
The System Charge is determined by applying the current Levelized Fixed Charge Rate (LFCR), to the Company's cost of purchasing and installing the System.
Proposed Rate
There are no changes to this tariff schedule.

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

Current Rate

	Lamp Watts	kW/ Luminaire	Annual kWh	Rate/Unit
Standard Fixtures (Cobra Head)				
Mercury Vapor				
7,000 lumen (Open Refractor)	175	0.205	853	$ 8.73
7,000 lumen	175	0.210	874	$11.17
10,000 lumen	250	0.292	1,215	$13.04
21,000 lumen	400	0.460	1,914	$16.75
Metal Halide				
14,000 lumen	175	0.210	874	$11.17
20,500 lumen	250	0.307	1,215	$13.06
36,000 lumen	400	0.460	1,914	$16.75
Sodium Vapor				
9,500 lumen (Open Refractor)	100	0.117	487	$ 7.68
9,500 lumen	100	0.117	487	$ 9.99
16,000 lumen	150	0.171	711	$ 11.27
22,000 lumen	200	0.228	948	$ 12.47
27,500 lumen	200	0.228	948	$ 12.47
50,000 lumen	400	0.471	1,959	$ 14.53
Decorative Fixtures (a)				
Mercury Vapor				
7,000 lumen (Town & Country)	175	0.205	853	$ 13.38
7,000 lumen (Holophane)	175	0.210	874	$17.24
7,000 lumen (Gas Replica)	175	0.210	874	$41.66
7,000 lumen (Aspen)	175	0.210	874	$25.77
Sodium Vapor				
9,500 lumen (Town & Country)	100	0.117	487	$21.10
9,500 lumen (Holophane)	100	0.128	532	$22.86
9,500 lumen (Rectilinear)	100	0.117	487	$18.79
9,500 lumen (Gas Replica)	100	0.128	532	$43.94
9,500 lumen (Aspen)	100	0.128	532	$26.63
9,500 lumen (Traditionaire)	100	0.117	487	$21.10
9,500 lumen (Granville Acorn)	100	0.128	532	$26.63
22,000 lumen (Rectilinear)	200	0.246	1,023	$22.37
50,000 lumen (Rectilinear)	400	0.471	1,959	$28.38
50,000 lumen (Setback)	400	0.471	1,959	$44.15

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

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

Proposed Rate

CANCELLED & WITHDRAWN

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

Current Rate

Company owned

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

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

	Lamp Watts	kW/Unit	Annual kW/unit	Rate/Unit
Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$ 7.10
b. 2,500 lumen Mercury Vapor	100	0.109	453	$ 6.72
c. 21,000 lumen Mercury Vapor	400	0.460	1,914	$ 10.66
Customer owned				
Steel boulevard units served underground with limited maintenance by Company				
a. 2,500 lumen Incandescent – Series	148	0.148	616	$5.44
b. 2,500 lumen Incandescent – Multiple	189	0.189	786	$6.92

Base Fuel Cost

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

Proposed Rate

Company owned

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

The cable span charge of $.84 per each increment of 25 feet of secondary wiring shall be added to the Rate/unit charge for each increment of secondary wiring beyond the first 25 feet from the pole base.

	Lamp Watts	kW/Unit	Annual kW	Rate/Unit
Street light units served overhead distribution				
a. 2,500 lumen Incandescent	189	0.189	786	$ 7.94

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

Base Fuel Cost

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

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

Current Rate

Private outdoor lighting units:

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

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

Outdoor lighting units served in underground residential distribution areas:

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

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

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

Flood lighting units served in overhead distribution areas:

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

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

Base Fuel Cost

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

Proposed Rate

CANCELLED & WITHDRAWN

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

Current Rate

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

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

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

Base Fuel Cost

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

Proposed Rate

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

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

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

Base Fuel Cost

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

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

Current Rate:

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

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

Base Fuel Cost

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

Proposed Rate:

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

Base Fuel Cost

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

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

Current Rate:

Rate

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

Monthly Service Payment = Estimated Levelized Capital Cost + Estimated Expenses

Where:

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

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

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

MONTHLY BILL

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

Proposed Rate:

There are no proposed changes in this rider.

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

Current Rate:

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

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

Proposed Rate:

There are no proposed changes in this rider.

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

Current Rate:

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

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

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

Proposed Rate:

There are no proposed changes in this rider.

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

Current Rate:

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

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

Proposed Rate:

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

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

Current Rate:

CHARGES

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

Proposed Rate:

There are no proposed changes in this rider.

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

Current Rate:

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

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

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

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

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

Proposed Rate:

There are no proposed changes in this rider.

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

Current Rate:

BACKUP DELIVERY POINT (TRANSMISSION/DISTRIBUTION) CAPACITY

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

NET MONTHLY BILL

1. Connection Fee

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

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

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

Proposed Rate:
There are no proposed changes in this rider.

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

Current Rate:

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

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

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

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

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

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

Subtract:

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

Proposed Rate:

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

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

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

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

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

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

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

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

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

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

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

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

Add:

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

Subtract:

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

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

Current Rate:

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

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

PROFIT SHARING RIDER FACTORS

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

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

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

where:

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

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

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

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

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

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

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

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

Proposed Rate:

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

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

PROFIT SHARING RIDER FACTORS

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

Rider PSM Factor = (OSS + NF + CAP + REC + R) / S x 0.90

where:

OSS = Net proceeds from off-system power sales.

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

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

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

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

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

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

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

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

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

Bad Check Charge
(Electric Tariff Sheet No. 90)

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

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

Current Rate:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00).
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00).
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed thirty-eight dollars ($38.00).
E. Where electric service was disconnected at the pole because the Company was unable to gain access to the meter, the reconnection charge shall be sixty-five dollars ($65.00). If the gas service is also reconnected the charge shall be ninety dollars ($90.00).
F. If the Company receives notice after 2:30 p.m. of a customer's desire for same day reinstatement of service and if the reconnection cannot be performed during normal business hours, the after hour

reconnection charge for connection shall be an additional twenty-five dollars ($25.00). Customers will be notified of the additional $25.00 charge for reconnection at the meter or at the pole at the time they request same day service.

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

Proposed Rate:

A. The reconnection charge for service which has been disconnected due to enforcement of Rule 3 shall be twenty-five dollars ($25.00) for reconnections that can be accomplished remotely or seventy-five dollars ($75.00) for reconnections that cannot be accomplished remotely.
B. The reconnection charge for service which has been disconnected within the preceding twelve months at the request of the customer shall be twenty-five dollars ($25.00) for reconnections that can be accomplished remotely or seventy-five dollars ($75.00) for reconnections that cannot be accomplished remotely.
C. If service is discontinued because of fraudulent use thereof, the Company may charge and collect in addition to the reconnection charge of twenty-five dollars ($25.00) for reconnections that can be accomplished remotely or seventy-five dollars ($75.00) for reconnections that cannot be accomplished remotely, the expense incurred by the Company by reason of such fraudulent use, plus an estimated bill for electricity used, prior to the reconnection of service.
D. If both the gas and electric services are reconnected at one time, the total charge shall not exceed eighty-eight dollars ($88.00).
E. Where electric service was disconnected at the pole because the Company was unable to gain access to the meter, the reconnection charge shall be one hundred twenty-five dollars ($125.00). If the gas service is also reconnected the charge shall be one hundred fifty dollars ($150.00).
F. If the Company receives notice after 2:30 p.m. of a customer's desire for same day reinstatement of service and if the reconnection cannot be performed during normal business hours, and the reconnection cannot be performed remotely, the after hour reconnection charge for connection shall be an additional twenty-five dollars ($25.00). Customers will be notified of the additional $25.00 charge for reconnection at the meter or at the pole at the time they request same day service.
G. If a Company employee, whose original purpose was to disconnect the service, has provided the customer a means to avoid disconnection, service which otherwise would have been disconnected shall remain intact, and no reconnection charge shall be assessed. However, a collection charge of fifty dollars ($50.00) may be assessed, but only if a Company employee actually makes a field visit to the customer's premises.

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

Current Rate:
The following annual rental shall be charged for the use of each of the Company's poles:
Two-user pole: $4.60 annual rental
Three-user pole: $4.00 annual rental

Proposed Rate:
The following annual rental shall be charged for the use of each of the Company's poles:
Two-user pole: $6.35 annual rental
Three-user pole: $5.31 annual rental

Cogeneration and Small Power Production Sale and Purchase Tariff-100 kW or Less
(Electric Tariff Sheet No. 93)

Current Rate:
Rates for Purchases from qualifying facilities:
Purchase Rate shall be $0.03078/kWh for all kilowatt-hours delivered.
Proposed Rate:
Rates for Purchases from qualifying facilities:
Energy Purchase Rate shall be $0.027645/kWh for all kilowatt-hours delivered.
Capacity Purchase Rate shall be $3.90/kW-month for eligible capacity utilized by Company and approved by PJM in Company's Fixed Resource Requirements (FRR) plan.

Cogeneration and Small Power Production Sale and Purchase Tariff-Greater Than 100 kW
(Electric Tariff Sheet No. 94)

Current Rate:
The Purchase Rate for all kilowatt-hours delivered shall be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour of the billing month.
Proposed Rate:
The Energy Purchase Rate for all kilowatt-hours delivered shall be the PJM Real-Time Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour of the billing month.

Capacity Purchase Rate shall be $3.90/kW-month for eligible capacity utilized by Company and approved by PJM in Company's Fixed Resource Requirements (FRR) plan.

Local Franchise Fee
(Electric Tariff Sheet No. 95)

Current Rate:
There shall be added to the customer's bill, listed as a separate item, an amount equal to the fee now or hereafter imposed by local legislative authorities, whether by ordinance, franchise or other means, which fee is based on the gross receipts collected by the Company from the sale of electricity to customers within the boundaries of the particular legislative authority. Such amount shall be added exclusively to bills of customers receiving service within the territorial limits of the authority imposing the fee.

Where more than one such fee is imposed, each of the charges applicable to each customer shall be added to the customer's bill and listed separately.

Where the local legislative authority imposes a flat, fixed amount on the Company, the fee applied to the bills of customers receiving service within the territorial boundaries of that authority, shall be in the form of a flat dollar amount.

The amount of such fee added to the customer's bill shall be determined in accordance with the terms of the ordinance, franchise or other directive agreed to by the Company.
Proposed Rate:
There are no proposed changes to this rate.

Underground Residential Distribution Policy-Rate UDP-R
(Electric Tariff Sheet No. 96)

Current Rate:
Single Family Houses.

A. $2.15 per front foot for all primary extensions. Primary extension on private property will be charged $2.15 per linear trench foot; and
B. An additional $2.00 per linear trench foot shall be charged where extremely rocky conditions are encountered, such conditions being defined as limestone or other hard stratified material in a continuous volume of at least one cubic yard or more which cannot be removed using ordinary excavation equipment.

Multi-Family Units.

There shall be no charge except where extremely rocky conditions are encountered, then the $2.00 per linear trench foot, as stated and defined above, shall be charged.

Proposed Rate:
Single Family Houses.

A. $2.15 per front foot for all primary extensions. Primary extension on private property will be charged $2.15 per linear trench foot; and

B. An additional $2.00 per linear trench foot shall be charged where extremely rocky conditions are encountered, such conditions being defined as limestone or other hard stratified material in a continuous volume of at least one cubic yard or more which cannot be removed using ordinary excavation equipment.

Multi-Family Units.

There shall be no charge <u>except</u> where extremely rocky conditions are encountered, then the $2.00 per linear trench foot, as stated and defined above, shall be charged.

Targeted Underground for Service Improvement

Notwithstanding the above charges and upon Kentucky Public Service Commission approval, Company will waive above charges, maintain, and take ownership of customer service lines and equipment (curb, property line, or service lateral to the meter base) to and including the electric meter. This provision applies only to Company designated installations identified to improve the resiliency of service to the customer.

<u>General Underground Distribution Policy-Rate UDP-G</u>
<u>(Electric Tariff Sheet No. 97)</u>

<u>Current Rate</u>:

The charges shall be the difference between the Company's estimated cost to provide an underground system and the Company's estimated cost to provide an overhead system. In addition to the differential charge, the following provisions are applicable:

Single Family Houses or Multi-Family Units.

The customer may be required to provide the necessary trenching, backfilling, conduit system (if required) and transformer pads in place to Company's specifications.

Commercial and Industrial Units.

The customer shall:

a) Provide the necessary trenching and backfilling;

b) Furnish, install (concrete, if required), own and maintain all primary and/or secondary conduit system (with spares, if required) on private property meeting applicable codes and Company's specifications; and

c) Provide the transformer pad and secondary conductors.

Special Situations

In those situations where the Company considers the pad-mounted transformer installations unsuitable, the customer shall provide the vault designed to meet National Electric Code, other applicable codes, and Company specifications, the conduit to the vault area and the secondary cable to the transformer terminals. The Company shall provide the transformers, the primary vault wiring and make the secondary connection to the transformer terminals.

In large multiple cable installations, the customer shall provide the cable, provide and install the step bus mounted in the vault, and make necessary cable connections to the step bus to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the step bus.

The customer shall extend the bus duct into the vault to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the bus duct.

<u>Proposed Rate</u>:

The charges shall be the difference between the Company's estimated cost to provide an underground system and the Company's estimated cost to provide an overhead system. In addition to the differential charge, the following provisions are applicable:

Single Family Houses or Multi-Family Units.

The customer may be required to provide the necessary trenching, backfilling, conduit system (if required) and transformer pads in place to Company's specifications.

Commercial and Industrial Units.

The customer shall:

a) Provide the necessary trenching and backfilling;

b) Furnish, install (concrete, if required), own and maintain all primary and/or secondary conduit system (with spares, if required) on private property meeting applicable codes and Company's specifications; and

c) Provide the transformer pad and secondary conductors.

Special Situations

In those situations where the Company considers the pad-mounted transformer installations unsuitable, the customer shall provide the vault designed to meet National Electric Code, other applicable codes, and Company specifications, the conduit to the vault area and the secondary cable to the transformer terminals. The Company shall provide the transformers, the primary vault wiring and make the secondary connection to the transformer terminals.

In large multiple cable installations, the customer shall provide the cable, provide and install the step bus mounted in the vault, and make necessary cable connections to the step bus to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the step bus.

The customer shall extend the bus duct into the vault to the Company's specifications. The Company shall provide and install connections from the transformer terminals to the bus duct.

Targeted Underground for Service Improvement

Notwithstanding the above charges and upon Kentucky Public Service Commission approval, Company will waive above charges, maintain, and take ownership of customer service lines and equipment (curb, property line, or service lateral to the meter base) to and including the electric meter. This provision applies only to Company designated installations identified to improve the resiliency of service to the customer.

Real Time Pricing Program- Rate RTP
(Electric Tariff Sheet No. 99)

Current Rate:

BASELINE CHARGE

The Baseline Charge is independent of Customer's currently monthly usage, and is designed to achieve bill neutrality with the Customer's standard offer tariff if no change in electricity usage pattern occurs (less applicable program charges). The Baseline Charge is calculated at the end of the billing period and changes each billing period to maintain bill neutrality for a Customer's CBL.

The Baseline Charge will be calculated as follows:

BC = (Standard Bill @ CBL)

Where:

BC = Baseline Charge

Standard Bill @ CBL = Customer's bill for a specific month on the applicable Rate Schedule including applicable Standard Contract Riders using the CBL to establish the applicable billing determinants.

The CBL shall be adjusted to reflect applicable metering adjustments under the Rate Schedule. All applicable riders shall be excluded from the calculation of the Baseline Charge.

PRICE QUOTES

The Company will send to Customer, within two hours after the wholesale prices are published by PJM each day, Price Quotes to be charged the next day. Such Price Quotes shall include the applicable Commodity Charge, the Energy Delivery Charge and the Ancillary Services Charge.

The Company may send more than one-day-ahead Price Quotes for weekends and holidays identified in Company's tariffs. The Company may revise these prices the day before they become effective.

The Company is not responsible for failure of Customer to receive and act upon the Price Quotes. It is Customer's responsibility to inform Company of any failure to receive the Price Quotes the day before they become effective.

COMMODITY CHARGE

The Commodity Charge is a charge for generation. The applicable hourly Commodity Charge (Credit) shall be applied on an hour by hour basis to Customer's incremental (decremental) usage from the CBL.

Charge (Credit) For Each kW Per Hour From The CBL:

For kWht above the CBLt, CCt = MVGt x LAF

For kWht below the CBLt, CCt = MVGt x 80% x LAF

Where:

LAF = loss adjustment factor
= 1.0530 for Rate TS
= 1.0800 for Rate DP
= 1.1100 for Rate DS

MVGt = Market Value Of Generation As Determined By Company for hour t

The MVGt will be based on the expected market price of capacity and energy for the next day. The expected market price shall be the PJM Real-Time Total Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour.

The kW per hour incremental or decremental usage from the CBL shall be adjusted to reflect applicable metering adjustments under the standard Rate Schedule.

ENERGY DELIVER CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

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

ANCILLARY SERVICES CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

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

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $183.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

Proposed Rate:

BASELINE CHARGE

The Baseline Charge is independent of Customer's currently monthly usage, and is designed to achieve bill neutrality with the Customer's standard offer tariff if no change in electricity usage pattern occurs (less applicable program charges). The Baseline Charge is calculated at the end of the billing period and changes each billing period to maintain bill neutrality for a Customer's CBL.

The Baseline Charge will be calculated as follows:

BC = (Standard Bill @ CBL)

Where:

BC = Baseline Charge

Standard Bill @ CBL = Customer's bill for a specific month on the applicable Rate Schedule including applicable Standard Contract Riders using the CBL to establish the applicable billing determinants.

The CBL shall be adjusted to reflect applicable metering adjustments under the Rate Schedule. All applicable riders shall be excluded from the calculation of the Baseline Charge.

PRICE QUOTES

The Company will send to Customer, within two hours after the wholesale prices are published by PJM each day, Price Quotes to be charged the next day. Such Price Quotes shall include the applicable Commodity Charge, the Energy Delivery Charge and the Ancillary Services Charge.

The Company may send more than one-day-ahead Price Quotes for weekends and holidays identified in Company's tariffs. The Company may revise these prices the day before they become effective.

The Company is not responsible for failure of Customer to receive and act upon the Price Quotes. It is Customer's responsibility to inform Company of any failure to receive the Price Quotes the day before they become effective.

COMMODITY CHARGE

The Commodity Charge is a charge for generation. The applicable hourly Commodity Charge (Credit) shall be applied on an hour by hour basis to Customer's incremental (decremental) usage from the CBL.

Charge (Credit) For Each kW Per Hour From The CBL:

For kWht above the CBLt, CCt = MVGt x LAF
For kWht below the CBLt, CCt = MVGt x 80% x LAF

Where:

LAF = loss adjustment factor
= 1.0530 for Rate TT
= 1.0800 for Rate DP and Rate DT
= 1.1100 for Rate DS

MVGt = Market Value Of Generation As Determined By Company for hour t

The MVGt will be based on the expected market price of capacity and energy for the next day. The expected market price shall be the PJM Day-Ahead Total Locational Marginal Price for power at the DEK Aggregate price node, inclusive of the energy, congestion and losses charges, for each hour.

The kW per hour incremental or decremental usage from the CBL shall be adjusted to reflect applicable metering adjustments under the standard Rate Schedule.

ENERGY DELIVER CHARGE

Charge (Credit) For Each kW Per Hour From The CBL

Secondary Service .... $0.015412 per kW Per Hour
Primary Service .... $0.012471 per kW Per Hour

Transmission Service .... $0.006472 per kW Per Hour

PROGRAM CHARGE

Company will provide Internet based communication software to be used to provide Customer with the Price Quotes. Customer will be responsible for providing its own Internet access. A charge of $183.00 per billing period per site shall be added to Customer's bill to cover the additional billing, administrative, and cost of communicating the hourly Price Quotes associated with the RTP Program.

Meter Data Charges-Rate MDC
(This Schedule Renamed as Meter Data Charges for Enhanced Usage Data Services-Rate MDC)
(Electric Tariff Sheet No. 101)

Current Rate:

Electronic monthly interval data with graphical capability accessed via the Internet (En-Focus™) $20.00 per month

Proposed Rate:

Electronic monthly interval data with graphical capability accessed via the Internet with (EPO™) $20.00 per month

Duke Energy Kentucky proposes the following new rate and rider schedules: Rate LED, LED Outdoor Lighting, Rider DCI, Distribution Capital Investment Rider, Rider FTR, FERC Transmission Cost Reconciliation Rider, and Rider ESM, Environmental Surcharge Mechanism. As indicated above, the following schedules are proposed to be eliminated: Rate RTP-M (Real Time Pricing – Market Based Pricing), Rate OL (Outdoor Lighting Service), and Rate NSP (Private Outdoor Lighting for Non-Standard Units).

Rate LED – LED Outdoor Area Lighting Rate
(Electric Tariff Sheet No. 64)

Proposed Rate:

NET MONTHLY BILL

Computed in accordance with the following charges:

1. Base Rate

All kWh $0.041936 per kWh

The rate shown above includes a charge of $0.023837 per kilowatt-hour reflecting the base cost of fuel.

2. Applicable Riders

The following riders are applicable pursuant to the specific terms contained within each rider:

Sheet No. 76, Rider ESM, Environmental Surcharge Mechanism Rider
Sheet No. 80, Rider FAC, Fuel Adjustment Clause
Sheet No. 82, Rider PSM, Profit Sharing Mechanism
Sheet No. 125, Rider DCI, Distribution Capital Investment Rider
Sheet No. 126, Rider FTR, FERC Transmission Cost Reconciliation Rider

3. Monthly Maintenance, Fixture, and Pole Charges:

I. Fixtures				Per Unit Per Month		
Billing Type	Description	Initial Lumens	Lamp Wattage	Monthly kWh	Fixture	Maintenance
LF-LED-50W-SL-BK-MW	50W Standard LED-BLACK	4,521	50	17	$5.44	$4.38
LF-LED-70W-SL-BK-MW	70W Standard LED-BLACK	6,261	70	24	$5.43	$4.38
LF-LED-110W-SL-BK-MW	110W Standard LED-BLACK	9,336	110	38	$6.16	$4.38
LF-LED-150W-SL-BK-MW	150W Standard LED-BLACK	12,642	150	52	$8.16	$4.38
LF-LED-220W-SL-BK-MW	220W Standard LED-BLACK	18,641	220	76	$9.25	$5.34
LF-LED-280W-SL-BK-MW	280W Standard LED-BLACK	24,191	280	97	$11.38	$5.34
LF-LED-50W-DA-BK-MW	50W Deluxe Acorn LED-BLACK	5,147	50	17	$15.87	$4.38
LF-LED-50W-AC-BK-MW	50W Acorn LED-BLACK	5,147	50	17	$14.30	$4.38
LF-LED-50W-MB-BK-MW	50W Mini Bell LED-BLACK	4,500	50	17	$13.48	$4.38
LF-LED-70W-BE-BK-MW	70W Bell LED-BLACK	5,508	70	24	$17.17	$4.38
LF-LED-50W-TR-BK-MW	50W Traditional LED-BLACK	3,230	50	17	$10.36	$4.38
LF-LED-50W-OT-BK-MW	50W Open Traditional LED-BLACK	3,230	50	17	$10.36	$4.38
LF-LED-50W-EN-BK-MW	50W Enterprise LED-BLACK	3,880	50	17	$13.93	$4.38
LF-LED-70W-ODA-BK-MW	70W LED Open Deluxe Acorn	6,500	70	24	$15.48	$4.38
LF-LED-150W-TD-BK-MW	150W LED Teardrop	12,500	150	52	$20.78	$4.38
LF-LED-50W-TDP-BK-MW	50W LED Teardrop Pedestrian	4,500	50	17	$16.86	$4.38
220W LED SHOEBOX	220W LED Shoebox	18,500	220	76	$14.39	$5.34
LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17	$5.44	$4.38
LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24	$5.43	$4.38
LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38	$6.16	$4.38
LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52	$8.16	$4.38
LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52	$8.16	$4.38
LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76	$9.25	$5.34
LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97	$11.38	$5.34
LF-LED-50W-DA-BK-MW	LED 50W DELUXE ACORN BLACK TYPE III 4000K	5,147	50	17	$15.87	$4.38
LF-LED-70W-ODA-BK-MW	LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	6,500	70	24	$15.48	$4.38
LF-LED-50W-AC-BK-MW	LED 50W ACORN BLACK TYPE III 4000K	5,147	50	17	$14.30	$4.38
LF-LED-50W-MB-BK-MW	LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	4,500	50	17	$13.48	$4.38
LF-LED-70W-BE-BK-MW	LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	5,508	70	24	$17.17	$4.38
LF-LED-50W-TR-BK-MW	LED 50W TRADITIONAL BLACK TYPE III 4000K	3,303	50	17	$10.36	$4.38
LF-LED-50W-OT-BK-MW	LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	3,230	50	17	$10.36	$4.38
LF-LED-50W-EN-BK-MW	LED 50W ENTERPRISE BLACK TYPE III 4000K	3,880	50	17	$13.93	$4.38
LF-LED-150W-TD-BK-MW	LED 150W LARGE TEARDROP BLACK TYPE III 4000K	12,500	150	52	$20.78	$4.38
LF-LED-50W-TDP-BK-MW	LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	4,500	50	17	$16.86	$4.38
LF-LED-220W-SB-BK-MW	LED 220W SHOEBOX BLACK TYPE IV 4000K	18,500	220	76	$14.39	$5.34
LF-LED-150W-BE-BK-MW	150W Sanibel	39,000	150	52	$17.17	$4.38
LF-LED-420W-SB-BK-MW	420W LED Shoebox	39,078	420	146	$21.47	$5.34
LF-LED-50W-NB-GY-MW	50W Neighborhood	5,000	50	17	$4.43	$4.38
LF-LED-50W-NBL-GY-MW	50W Neighborhood with Lens	5,000	50	17	$4.62	$4.38

II. Poles		
Billing Type	Description	Charge per Month per Unit
LP-12-C-PT-AL-AB-TT-BK-MW	12' C-Post Top - Anchor Base-Black	$10.68
LP-25-C-DV-AL-AB-TT-BK-MW	25' C-Davit Bracket- Anchor Base-Black	$28.10
LP-25-C-BH-AL-AB-TT-BK-MW	25' C-Boston Harbor Bracket- Anchor Base-Black	$28.40
LP-12-E-AL-AB-TT-BK-MW	12' E-AL - Anchor Base-Black	$10.68
15310-40FTALEMB-OLE	35' AL-Side Mounted-Direct Buried Pole	$18.08
15320-30FTALAB-OLE	30' AL-Side Mounted-Anchor Base	$13.93
15320-35FTALAB-OLE	35' AL-Side Mounted-Anchor Base	$13.55
15320-40FTALAB-OLE	40' AL-Side Mounted-Anchor Base	$16.76
POLE-30-7	30' Class 7 Wood Pole	$6.62
POLE-35-5	35' Class 5 Wood Pole	$7.20
POLE-40-4	40' Class 4 Wood Pole	$10.84
POLE-45-4	45' Class 4 Wood Pole	$11.24
15210-20BRZSTL-OLE	20' Galleria Anchor Based Pole	$9.55
15210-30BRZSTL-OLE	30' Galleria Anchor Based Pole	$11.30
15210-35BRZSTL-OLE	35' Galleria Anchor Based Pole	$32.49
LP-12-A-AL-AB-TT-BK-MW	MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.47
LP-12-A-AL-DB-TT-BK-MW	MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black	$5.54
LP-15-A-AL-AB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.66
LP-15-A-AL-DB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$5.77
LP-20-A-AL-AB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.99
LP-20-A-AL-DB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$10.71
LP-25-A-AL-AB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$8.28
LP-25-A-AL-DB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$11.93
LP-30-A-AL-AB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$9.79
LP-30-A-AL-DB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$13.28
LP-35-A-AL-AB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$11.30
LP-35-A-AL-DB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$14.35
LP-12-B-AL-AB-TT-GN-MW	MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$7.89
LP-12-C-PT-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$10.68
LP-16-C-DV-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$14.29
LP-25-C-DV-AL-AB-TT-BK-MW	MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$28.10
LP-16-C-BH-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$11.46
LP-25-C-BH-AL-AB-TT-BK-MW	MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$28.40
LP-12-D-AL-AB-TT-GN-MW	MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$10.57
LP-12-E-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$10.68
LP-12-F-AL-AB-TT-GN-MW	MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie	$11.44
15210-20BRZSTL-OLE	MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$9.55
15210-30BRZSTL-OLE	MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$11.30
15210-35BRZSTL-OLE	MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$32.49
15310-40FTALEMB-OLE	MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$18.08
15320-30FTALAB-OLE	MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE	$13.93
15320-35FTALAB-OLE	MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE	$13.55
15320-40FTALAB-OLE	MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE	$16.76
POLE-30-7	MW-POLE-30-7	$6.62
POLE-35-5	MW-POLE-35-5	$7.20
POLE-40-4	MW-POLE-40-4	$10.84
POLE-45-4	MW-POLE-45-4	$11.24

Proposed Rider ESM – Environmental Surcharge Mechanism
(Electric Tariff Sheet No. 76)

Proposed Rate:
INITIAL FACTOR VALUES

MESF	=	0.00000%
BESF	=	0.00000%

Proposed Rider DCI – Distribution Capital Investment Rider
(Electric Tariff Sheet No. 125)

Proposed Rate:
CHARGES

The applicable energy or demand charge for electric service shall be increased or decreased to the nearest $0.000001 per kWh or $0.01 per kW to recover the revenue requirement associated with incremental distribution capital costs incurred by the Company. This Rider shall be adjusted periodically to recover amounts authorized by the Commission.

Rate Group	Rate ($ / kWh)
Rate RS, Residential Service	0.000000
Rate EH, Optional Rate for Electric Space Heating	0.000000
Rate GS-FL, Optional General Service Rate for Small Fixed Loads	0.000000
Rate SP, Seasonal Sports Service	0.000000
Rate SL, Street Lighting Service	0.000000
Rate TL, Traffic Lighting Service	0.000000
Rate UOLS, Unmetered Outdoor Lighting	0.000000
Rate NSU, Street Lighting Service for Non-Standard Units	0.000000
Rate SC, Street Lighting Service – Customer Owned	0.000000
Rate SE, Street Lighting Service – Overhead Equivalent	0.000000
Rate LED, LED Outdoor Lighting Electric Service	0.000000
	($ / kW)
Rate DS, Service at Secondary Distribution Voltage	0.00
Rate DP, Service at Primary Distribution Voltage	0.00
Rate DT, Time-of-Day Rate for Service at Distribution Voltage – Primary	0.00
Rate DT, Time-of-Day Rate for Service at Distribution Voltage – Secondary	0.00

Proposed Rider FTR – FERC Transmission Cost Reconciliation Rider
(Electric Tariff Sheet No. 126)

Proposed Rate:
RIDER FTR FACTORS

Rate Group	Rate ($ / kWh)
Rate RS, Residential Service	0.000000
Rate DS, Service at Secondary Distribution Voltage	0.000000
Rate DP, Service at Primary Distribution Voltage	0.000000
Rate DT, Time-of-Day Rate for Service at Distribution Voltage	0.000000
Rate EH, Optional Rate for Electric Space Heating	0.000000
Rate GS-FL, General Service Rate for Small Fixed Loads	0.000000
Rate SP, Seasonal Sports Service	0.000000
Rate SL, Street Lighting Service	0.000000
Rate TL, Traffic Lighting Service	0.000000
Rate UOLS, Unmetered Outdoor Lighting	0.000000
Rate NSU, Street Lighting Service for Non-Standard Units	0.000000
Rate SC, Street Lighting Service – Customer Owned	0.000000
Rate SE, Street Lighting Service – Overhead Equivalent	0.000000
Rate LED, LED Street Lighting Service	0.000000
Rate TT, Time-of-Day Rate for Service at Transmission Voltage	0.000000
Other	0.000000

In addition, Duke Energy Kentucky proposes to change text of the following tariffs: Sheet No. 24 Service Regulations Section V – Metering, Sheet No. 25 Service Regulations Section VI – Billing and Payment, Sheet No. 98 Electricity Emergency Procedures for Long-Term Fuel Shortages, and Sheet No. 100 Emergency Electric Procedures.

The foregoing rates reflect a proposed increase in electric revenues of approximately $48,646,213 or 14.96% over current total electric revenues to Duke Energy Kentucky. The estimated amount of increase per customer class is as follows:

Rate RS, Residential Service:	$22,855,269 or 17.36%;
Rate DS, Service at Distribution Voltage:	$13,198,789 or 14.30%;
Rate DT, Time-of-Day Rate for Service at Distribution Voltage:	$10,516,009 or 13.31%;
Rate EH, Optional Rate for Electric Space Heating:	$91,708 or 14.23%;
Rate SP, Seasonal Sports Service:	$3,343 or 11.41%;
Rate GS-FL, General Service Rate for Small Fixed Loads:	$86,768 or 14.38%;
Rate DP, Service at Primary Distribution Voltage:	$167,667 or 17.57%;
Rate TT, Time-of-Day Rate for Service at Transmission Voltage:	$1,416,419 or 11.12%;
Rate SL, Street Lighting Service:	$159,847 or 11.87%;
Rate TL, Traffic Lighting Service:	$8,413 or 11.75%;
Rate UOLS, Unmetered Outdoor Lighting Electric Service:	$24,006 or 11.71%;
Rate NSU, Street Lighting Service for Non-Standard Units:	$7,352 or 11.86%;
Rate SC, Street Lighting Service-Customer Owned:	$435 or 11.72%;
Rate SE, Street Lighting Service-Overhead Equivalent:	$22,650 or 11.85%;
Bad Check Charge:	$0 or 0.0%;
Charge for Reconnection of Service (electric only):	$0 or 0.0%;
Rate DPA, Rate for Distribution Pole Attachments:	$60,176 or 35.0%;
Local Franchise Fee:	$0 or 0.0%;
Rate UDP-R, Underground Residential Distribution Policy:	$0 or 0.0%;
Rate UDP-G, General Underground Distribution Policy:	$0 or 0.0%;
Rate RTP, Experimental Real Time Pricing Program: (subset of other schedules)	$87,538 or 14.87%;
Rate MDC, Meter Data Charges:	$0 or 0.0%.

The average monthly bill for each customer class to which the proposed rates will apply will increase approximately as follows:

Rate RS, Residential Service:	$15.17 or 17.1%;
Rate DS, Service at Distribution Voltage:	$114.53 or 14.3%;
Rate DT, Time-of-Day Rate for Service at Distribution Voltage:	$3,848.79 or 13.5%;
Rate EH, Optional Rate for Electric Space Heating:	$98.45 or 15.8%;
Rate SP, Seasonal Sports Service:	$18.59 or 11.7%;
Rate GS-FL, General Service Rate for Small Fixed Loads:	$8.29 or 14.9%;
Rate DP, Service at Primary Distribution Voltage:	$3,269.80 or 17.9%;
Rate TT, Time-of-Day Rate for Service at Transmission Voltage:	$7,973.24 or 10.7%;
Rate SL, Street Lighting Service:	$1.15 or 11.8%;
Rate TL, Traffic Lighting Service:	$0.09 or 12.0%;
Rate UOLS, Unmetered Outdoor Lighting Electric Service:	$0.27 or 12.0%;
Rate OL-E, Outdoor Lighting Equipment Installation:	$0 or 0.0%;
Rate NSU, Street Lighting Service for Non-Standard Units:	$0.88 or 11.9%;
Rate SC, Street Lighting Service-Customer Owned:	$0.21 or 11.7%;
Rate SE, Street Lighting Service-Overhead Equivalent:	$0.92 or 11.9%;
Bad Check Charge:	$0 or 0.0%;
Charge for Reconnection of Service (electric only):	$0 or 0.0%;
Rate DPA, Rate for Distribution Pole Attachments:	$1.53 or 35.0%;
Rate RTP, Experimental Real Time Pricing Program:	$1,887.21 or 15.6%;
Rate MDC, Meter Data Charges:	$0 or 0.0%.

The rates contained in this notice are the rates proposed by Duke Energy Kentucky; however, the Kentucky Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice. Such action may result in rates for consumers other than the rates in this notice.

Any corporation, association, body politic or person with a substantial interest in the matter may, by written request within thirty (30) days after publication of this notice of the proposed rate changes, request leave to intervene; intervention may be granted beyond the thirty (30) day period for good cause shown. Such motion shall be submitted to the Kentucky Public Service Commission, P. O. Box 615, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615, and shall set forth the grounds for the request including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication the Commission may take final action on the application.

Intervenors may obtain copies of the application and other filings made by the Company by contacting Ms. Minna Rolfes-Adkins at 139 East Fourth Street, Cincinnati, Ohio 45202 or by telephone at (513) 287-4356. A copy of the application and other filings made by the Company is available for public inspection through the Commission's website at http://psc.ky.gov, at the Commission's office at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 am. To 4:30 p.m., and at the following Company offices: 4580 Olympic Boulevard, Erlanger, Kentucky 41018. Comments regarding the application may be submitted to the Public Service Commission through its website, or by mail at the following Commission address.

For further information contact:

PUBLIC SERVICE COMMISSION
COMMONWEALTH OF KENTUCKY
P. O. BOX 615
211 SOWER BOULEVARD
FRANKFORT, KENTUCKY 40602-0615
(502) 564-3940

DUKE ENERGY KENTUCKY
4580 OLYMPIC BOULEVARD
ERLANGER, KENTUCKY 41018
(513) 287-4315

List of Newspapers in Duke Energy Kentucky Territory

Campbell County Recorder
Covington Kentucky Enquirer
Falmouth Outlook
Kenton County Recorder
Warsaw Gallatin County News
Williamstown Grant County News

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807 KAR 5:001, SECTION 16(2)

Description of Filing Requirement:

Notice of intent. A utility with gross annual revenues greater than $5,000,000 shall notify the commission in writing of its intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

(a) The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.

(b) Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.

(c) Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.

Response:

See Duke Energy Kentucky's response to Filing Requirement KRS 278.180 [Tab 1].

Sponsoring Witness: James P. Henning

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(3)

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807 KAR 5:001, SECTION 16(3)

Description of Filing Requirement:

Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.

Response:

Notice given pursuant to 807 KAR 5:001, Section 17 satisfies the requirements of 807 KAR 5:051, Section 2. A copy of the customer notice is attached in response to Filing Requirement, 807 KAR 5:001, Section 16(1)(b)(5) [Tab 13].

Sponsoring Witness: James P. Henning

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807 KAR 5:001, SECTION 16(6)(a)

Description of Filing Requirement:

The financial data for the forecasted period shall be presented in the form of pro forma adjustments to the base period.

Response:

See Schedules D-2.1 through D-2.15 located in Schedule Book.

Witness Responsible: Robert H. Pratt

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(b)

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807 KAR 5:001, SECTION 16(6)(b)

Description of Filing Requirement:

Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.

Response:

See Schedules D-2.16 through D-2.35 for adjustments to the forecasted period located in Schedule Book. These adjustments are limited to the twelve (12) months immediately following the suspension period.

Witness Responsible:

Sarah E. Lawler - (D-2.17 thru D-2.20, D-2.22, D-2.23, D-2.25 thru D-2.27, D-2.29, and D-2.31 thru D-2.33)
Cynthia S. Lee - (D-2.16, D-2.21, and D-2.24)
Robert H. Pratt - (D-2.28, D-2.30, D-2.34, and D-2.35)

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DUKE ENERGY KENTUCKY
CASE NO. 2016-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(c)

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807 KAR 5:001, SECTION 16(6)(c)

Description of Filing Requirement:

Capitalization and net investment rate base shall be based on a thirteen (13) month average for the forecasted period.

Response:

Capitalization and Net Investment Rate Base for the Forecasted Period are based on a thirteen-month average.

Witness Responsible: Sarah E. Lawler

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(d)

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807 KAR 5:001, SECTION 16(6)(d)

Description of Filing Requirement:

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.

Response:

The Company will comply with this requirement.

Witness Responsible: Robert H. Pratt

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(e)

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807 KAR 5:001, SECTION 16(6)(e)

Description of Filing Requirement:

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.

Response:

The Company will prepare an alternative forecast if requested by the Commission.

Witness Responsible: Robert H. Pratt

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(6)(f)

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807 KAR 5:001, SECTION 16(6)(f)

Description of Filing Requirement:

The utility shall provide a reconciliation of the rate base and capital use to determine its revenue requirements.

Response:

See attached.

Witness Responsible: Sarah E. Lawler

DUKE ENERGY KENTUCKY, INC.
CASE NO. 2017-00321
RECONCILIATION OF CAPITALIZATION AND RATE BASE
THIRTEEN MONTH AVERAGE BALANCE ENDING MARCH 31, 2019

DATA: BASE PERIOD "X" FORECASTED PERIOD
TYPE OF FILING: "X" ORIGINAL UPDATED REVISED
WORK PAPER REFERENCE NO(S).:

FR 16(6)(f)
PAGE 1 OF 1
WITNESS RESPONSIBLE:
S. E. LAWLER

Line No.	Description	Source	Amount
1	Capitalization Allocated to Electric Operations	Schedule A	705,051,140
2	Net ARO not in Rate Base		16,116,171
3	Adjustments to Plant in Service	Sch. B-2.2 & B-3.1	1,925,269
4	Assets per Books not included in Rate Base:		
5	Other Property and Investments		(1,926,150)
6	Cash		(3,722,633)
7	Other Current Assets		(21,114,823)
8	Other Regulatory Assets		(47,435,281)
9	Other Deferred Debits		(27,215,744)
10	Subtotal		(101,414,631)
11	Liabilities per Books not included in Rate Base:		
12	Other Current liabilities		27,409,467
13	Other Non-current liabilities		10,788,685
14	Deferred Credits		26,737,421
15	Subtotal		64,935,573
16	Items included in Rate Base:		
17	Cash Working Capital Formula		14,215,407
18	Capitalization / Rate Base Differences		(624,368)
19	Subtotal		13,591,039
20	Total Variance		(4,846,579)
21	Electric Rate Base	Schedule B-1	700,204,561

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(a)

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807 KAR 5:001, SECTION 16(7)(a)

Description of Filing Requirement:

The written testimony of each witness the utility proposes to use to support its application, which shall include testimony from the utility's 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.

Response:

All testimony is provided under separate cover.

Sponsoring Witness: All Witnesses

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(b)

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807 KAR 5:001, SECTION 16(7)(b)

Description of Filing Requirement:

The utility's most recent capital construction budget containing at minimum a three (3) year forecast of construction expenditures.

Response:

See attached.

Sponsoring Witness: Robert H. Pratt / Joseph A. Miller / Anthony J. Platz

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Capital Expenditure Budget
Years 2017 - 2019

Line No.	Project ID / Description	CWIP Balance @ 12/31/16	Projected Expenditures 2017	2018	2019
1	NORMAL RECURRING CONSTRUCTION	18,729,420	51,443,440	70,670,959	39,661,660
2					
3	WD101209 - WGS CT 1 Overhaul #2	3,160,770	7,314,540	0	0
4	EB021422 - Precipitator Rebuild	627,694	8,749,392	26,224,855	0
5	WDC00004 - Install Fuel Oil System	160,162	3,366,990	36,621,265	15,000,000
6	EB020578 - East Bend 2 Dual Fuel Cofiring	0	1,543,412	2,141,357	4,013,122
7	EB020290 - Lined Retention Basin WEST	1,025,696	736,539	19,089,303	240,014
8	EB020745 - Lined Retention Basin EAST	0	0	75,313	4,092,541
9	EB020298 - East Bend SW / PW REROUTE	970,733	6,656,571	14,671,999	305,047
10	EB021281 - New East Bend Landfill Ph 2 of 8	0	1,052,812	2,512,716	12,522,926
11	EB021410 - Dry Bottom Ash Conversion	1,623,170	8,346,702	9,739,344	0
12	EBS01243 - New East Bend Landfill Ph 1 of 8	27,216,024	17,053,446	0	0
13	Advanced Metering Infrastructure	0	11,134,409	12,305,233	0
14	Solar Generation Facilities	34,936	13,431,325	1,160,870	0
15	TOTAL	53,548,604	130,829,579	195,213,215	75,835,310

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(c)

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807 KAR 5:001, SECTION 16(7)(c)

Description of Filing Requirement:

A complete description, which may be filed in written testimony form, of all factors used in preparing the utility's forecast period. All econometric models, variables, assumptions, escalation factors, contingency provisions, and changes in activity levels shall be quantified, explained, and properly supported.

Response:

Attached are a copy of the Budget Guidelines for 2017 and a summary of the assumptions that were used in developing the projected data in the base and forecasted test periods. Descriptions of the factors used in preparing the forecasted test period are also incorporated in each witness' pre-filed testimony.

Sponsoring Witness: Robert H. Pratt

2017 & 2018
BUDGET GUIDELINES AND ASSUMPTIONS

May 4, 2016

Version 1.0

Contents

1.0 General Guidelines for 2017 and 2018 Budgets

All guidance contained in this document is based on the best available information as of the published date. The contents and guidance are subject to change as business circumstances may require. **NOTE: This guidance does not include assumptions regarding Piedmont operational costs. Do not budget Piedmont operational expenses at this point in time. Further instructions will be provided at a later date.**

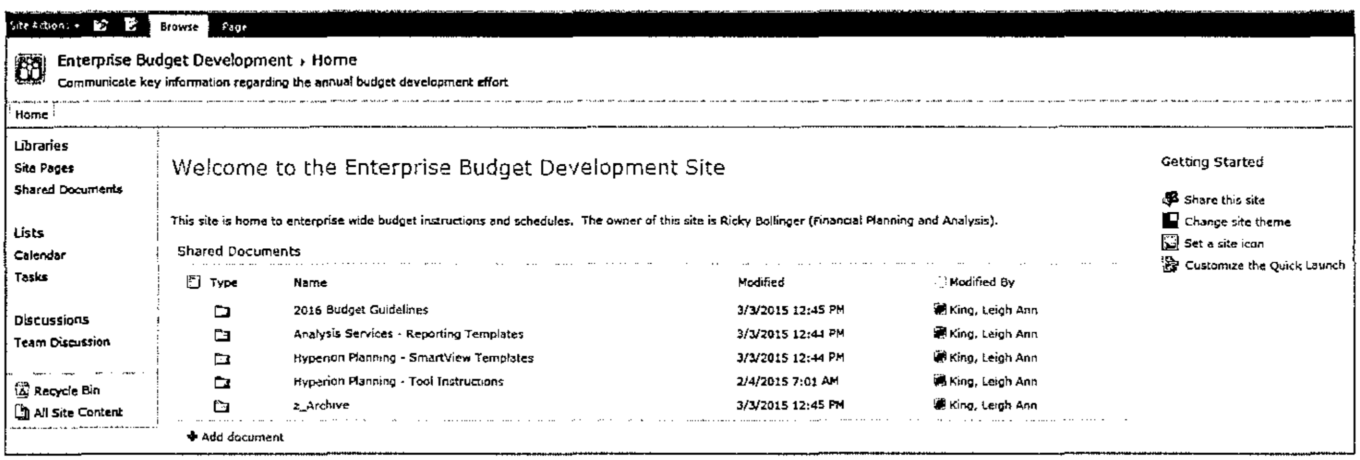
1.1 Key Changes for 2017/2018 Budgeting

- O&M and Capital budgets will be entered for two years.
  - Deadline for year two entry is same as year one (see section 2.0 for timeline)
  - Year two budget requirements (see section 1.3)
- Piedmont acquisition costs to achieve (CTA) budgets should use information from: CTA Instructions Piedmont
- User id entered on Send to Validation form – available in FiHUB
- Worker Cost/Labor Mapping cube enhancements:
  - Transfer workers to different RCs
  - Named contractor loads
  - Vacant positions available in Labor Mapping cube
- New Unit Cost cube to be used by T&D and Commercial budgeters – training mid-May
- The budget calendar has been updated - see section **2.0 Budget Timeline**
- Inflation and Loading rates have been updated
  - Section 3.2 Labor Inflation Rates and Labor Loading Rates
  - Section 4.3 Non-Labor Loading Rates (Stores/Freight/Handling)

1.2 Reference Material

A Budgeting link is available on the Finance Portal for various reference materials.

1. From the Portal, navigate to ***Work Related Sites → Finance***
2. Locate the ***Share Point Sites*** section, then select the ***Enterprise Budget Development*** link



1.3 Year Two Budgeting Requirements

- During this budget cycle, O&M and Capital budgets for two years will be completed (2017 and 2018).
- Targets have been issued for each year
- Year two budget details should be at the same level of detail as year one to support multi-year business/financial plans and certain regulatory filings.

- There are two ways to enter Year 2 data:
  - Directly in the Budgets Cube
    - New year 2 specific template
    - Ad hoc SmartView
  - Feed from Copperleaf Horizons or PowerPlan LRP

- There is a separate Send to Validation form for year two
- Budget allocations steps/stats for year one will be applied to year two. Results of allocations will be available in the HUB on a one day lag.
- The table below shows which scenarios are open for editing in each budget year:

Scenario	Year 1	Year 2
User Input	Open	Open
Labor Input**	Closed	Open
LRP Input*	Closed	Closed
Horizons Input*	Closed	Closed
Service Provider Input	Open	Open
Unit Cost Input**	Closed	Open
Unit Qty Input**	Closed	Open

* Year 1 and Year 2 are from external feeders (e.g., Copperleaf)
** Year 1 is developed in separate Hyperion Planning Cubes (e.g., Worker Cost / Labor)

1.4 Budget Development

Budgets should be prepared on an accrual basis and include a focus on accurate monthly timing of budgeted costs. The goal is to reduce actual versus budget timing variances for 2017 reporting by placing budget dollars in the months costs are expected to occur.

Costs should be directly charged to the legal entity (Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, etc.) benefiting from the services to the extent it is feasible.

Care should be taken to ensure that Service Agreements are in place for affiliate transactions.

1.5 Budget Systems

All 2017 and 2018 budgets (excluding PeopleSoft allocations) make their way to the Hyperion Planning Budget Tool, by direct entry or by an interface from Fossil Hydro and Nuclear long range planning tools to Hyperion Planning (i.e., PowerPlan LRP and Copperleaf Horizons, respectively).

- Fossil Hydro will plan all capital projects and outage projects using PowerPlan LRP; users cannot modify these budgets in Hyperion Planning
- Nuclear will plan all capital projects and non-routine O&M projects using Copperleaf Horizons; users cannot modify these budgets in Hyperion Planning
- All other budgets will be entered (directly or via spreadsheet upload) to Hyperion Planning

Monday- Sunday nights, Hyperion Planning budget data is sent to PeopleSoft for allocations / loadings, then sent to the FIHUB for reporting of "fully-loaded" budgets.

The Hyperion Planning user guide can be found on the portal by searching FIN2631. Additionally, you may contact your Budget Subject Matter Expert (SME) – See list below.

1.5.2 Subject Matter Experts

Cust Ops / Market Sol / Renew Gen Lisa Bryson - 704 382-9598

Transmission Carla Cook – 704 382-6579

Delivery Ops CAR - Amy Futrell – 919 546-2678; FL – Chris King – 727 820-5749; IN/OH/KY – Sherry Trebes – 513 287-3183

Gas Joe Shoemaker – 513 287-3971

Grid Solutions Mark Brooks - 704 382-0690

State Presidents Daniel Maddox - 980 373-2890

Nuclear Betsy Solakoglu – 919 362-2133 and Will Goebel – 980 373-1775

Fossil Hydro/ Ash / Other Gen Hadia Lugo - 980 373-9373

Strategic Services – IT and Other Michelle Cary - 704 382-9145

External Affairs / HR / Legal Joe Asbell - 980 373-8808

Commercial / International Kattie Aittola – 704 382-1303

Finance / CEO Staff Neena Chopra - 704 382-0716

FP&A Kathy Dimoff - 704 382-4795, Ricky Bollinger - 704 382-5885, Charlton Jacobs - 980 373-4594

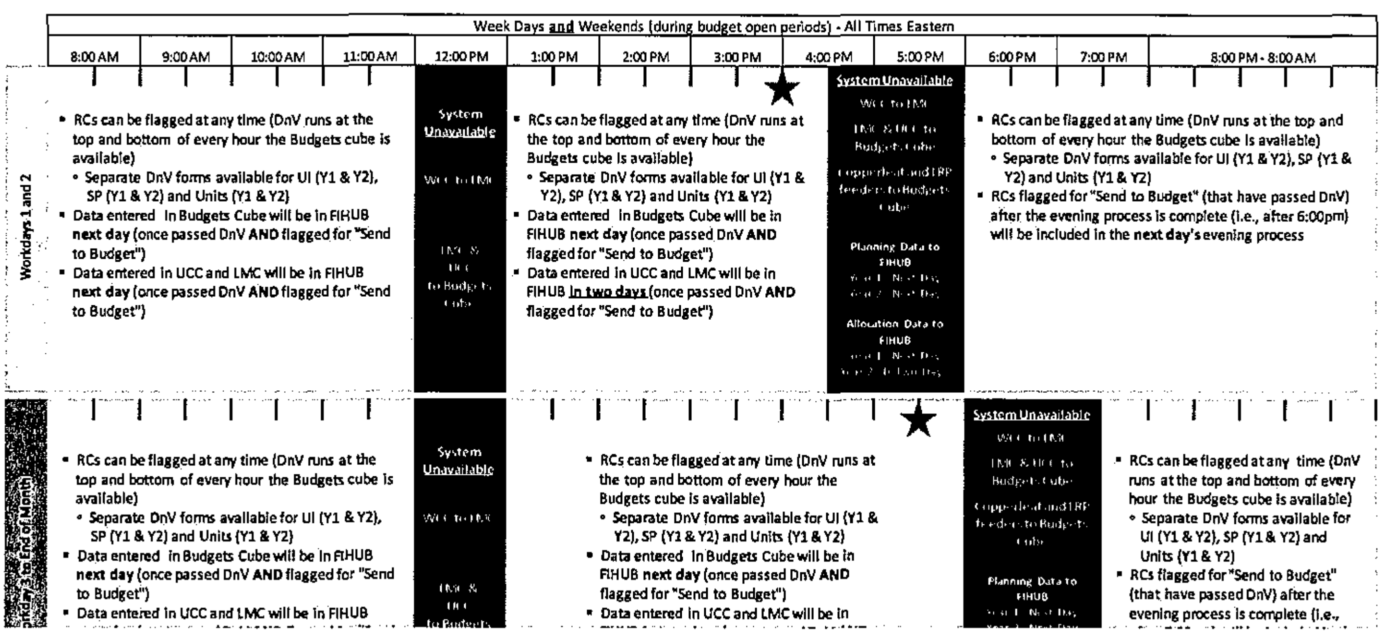
1.6 Budgeting Tool Availability and Data Flow

- Hyperion Planning Budget Tool daily processing times will occur based on the following schedule. During the first 2 days of close, the nightly processing cut-off will be 4:30pm. All other days, processing begins at 6:00pm.

- LRP (Fossil Hydro) and Horizons (Nuclear) will feed budget information to the Hyperion Planning Budget Tool according to those systems' operating/processing schedules.

- Budget data sent to PeopleSoft/FIHUB (Monday-Sunday) via the Hyperion Planning Budget Tool will be available in the FIHUB the next morning. PeopleSoft allocations and labor loadings are running Monday - Sunday. Year 1 (2017) data with allocations and labor loadings will be available the next day. Year 2 (2018) data with allocations and labor loadings will be available in two days.

The following timeline details system availability along with the budget data that is processed throughout the workday:



2.0 Budget Timeline

Below is a summary of the key dates for the 2017 and 2018 budgeting process. *Please note that the deadlines indicated are for final signoffs. Any internal department reviews must be completed prior to these final signoff dates.*

These dates reflect the calendar as planned, dates and events are subject to change as business circumstances may require.

Dates	Activity
[redacted]	[redacted]
April 20	Worker Cost populated in Hyperion Planning from HR ODS
Early May	Targets issued to functions
May 2	Hyperion Planning Budget Tool opens
August 26	O&M and Capital Budgets @ Target and locked – Last allocation run Friday 8/26
August 30	Forecasting loads '17 & '18 O&M and Capital from BARS into UI for 8x4v1
August 30	O&M special item templates for '19 - '21 due
September 6	Budget reopens for Cash Flow changes
September 27	2016 8x4v1 complete
October 14	O&M and Capital Budget @ Target and locked – last allocation run Friday 10/14
October 18 - 21	Fringe Benefit Loading Rates updated
October 24	Forecasting loads '17 & '18 O&M and Capital from BARS into UI for 8x4v2
[redacted]	[redacted]
November 1 - 18	Update Service Company, Commercial, and OH/KY allocations
November 11	2016 8x4v2 complete
[redacted]	[redacted]
December 15 - 18	Run monthly allocations
December 19	Forecasting loads '17 & '18 O&M and Capital from BARS into UI for 12x0
December 20	O&M special items and capital templates for '19 - '21 due
January 26	2016 12x0 complete
January 27 - Feb 6	Forecasting loads rest of Income Statement to budget tools (HP complete Feb 2, HFM complete Feb 6)
February 4 - 5	Budget scenario marked 'Final' for AvB reporting

3.0 Workforce Budgeting

3.1 Headcount Budgeting

Headcount (Duke employee and staff-aug contractors) and estimated wages will be collected for 2017 by using the Worker Cost application in Hyperion Planning.

With the exception of International, total employee and staff augmentation contractor costs are estimated in the Worker Cost applicaton by HR department ID and responsibility center. Analytics around headcount will be performed using the Worker Cost application data.

3.2 Labor Inflation Rates

The table below contains the preliminary wage increases that will be used to begin the 2017 budgeting process. Labor increases will be automatically applied to Worker Cost in Hyperion Planning after HR employee data is loaded. If labor budgets are loaded using the Labor Mapping cube, labor will feed in with increases layered in to the appropriate months. If labor is loaded using the Budgets Cube, be sure to budget the effects of labor increases in the appropriate months. TBD – "To Be Determined" guidance will be provided as information becomes available.

Category	Union	Date of Increase	2016 Wage Increase[1]	2017 Wage Increase Est.[1]	2018 Wage Increase Est.[1]
Non-Union	n/a	March 1	3.5% *(Total compensation including merit, promotion, etc.)*	3.5% *(Total compensation including merit, promotion, etc.)*	3.5% *(Total compensation including merit, promotion, etc.)*
Non-Union	Non-represented Craft	October 1	3.0% est. TBD – Early Summer 2016	TBD – Early Summer 2017	TBD – Early Summer 2018
Union	UWUA, IUU Local 600 (Technical)[2]	April 1	2.0%	2.0%	2.0%
Union	UWUA, IUU Local 600 (Clerical/Manual)[2]	April 1	2.0%	2.0%	2.0%
Union	IBEW 1347[2]	April 1	3.0%	TBD	TBD
Union	IBEW 1347-Matl Spec C, Meter Repair, Manual Techs[2]	April 1	1.0%	TBD	TBD
Union	IBEW 1393[2]	May 1	2.5%	2.5%	3.0%
Union	USW 12049[2]	May 15	2.5% est. TBD – May/June 2016	TBD	TBD
Union	USW 5541	May 15	2.5% est. TBD – May/June 2016	TBD	TBD
Union	USW 7202	October 1	3.0% est. TBD – Fall 2016	TBD – Fall 2017	TBD – Fall 2018
Union	IBEW 962	October 1	3.0% est. TBD – Fall 2016	TBD – Fall 2017	TBD – Fall 2018
Union	IBEW 962T	December 1	3.0% est. TBD – Fall 2016	TBD – Fall 2017	TBD – Fall 2018
Union	IBEW SCU-8 Florida (Main IBEW Florida)	December	3.00% – Fall 2015 (12/7/15 – 12-4/16)	TBD – Fall 2016	TBD – Fall 2016
Union	IBEW SCU-8 Florida (Hines Energy Complex)	March	3.00% – Fall 2015 (3/28/16 – 3-27/17)	TBD – March 2017	TBD – March 2017

Notes:
[1]*Estimates have been included where negotiations are pending. Estimates used are for budget purposes only and may not be representative of management's offer during future negotiations.*

[2]*Employees in the IBEW 1347, IBEW 1393, UWUA, and USW 12049 unions receive one week of prepaid sick time in the month of January. This week of prepaid sick time is calculated by the Worker Cost Cube process in Hyperion Planning.*

3.3 Labor Loading Rates

The table below contains the initial labor loading rates used for the 2017 & 2018 budgeting process.

Category	2017& 2018 Rate
Fringe Benefits	
DE Carolinas	17.55%
DE Progress	12.72%
DE Florida	17.14%
DE Indiana	27.30%
DE Kentucky	20.56%
DE Ohio	22.78%
DE Commercial Power	10.54%
DE International	14.53%
DE Business Services	21.38%
Payroll Tax	7.65%
Incentive	
Non-Union	10.50%
Union	3.00%

3.4 Incentives

STPP will be budgeted through incentive loading rates calculated at target performance. Executive stock based incentives, including EIP and the equity portion of CEIP, will be budgeted in a Human Resources responsibility center (RC 8937) and allocated to operating units as appropriate. Any incentives outside the aforementioned plans should be budgeted at the responsibility center level.

3.5 Payroll Cycle for Exempt and Non-Exempt Employees

All exempt employees should be budgeted assuming a semi-monthly pay cycle (two payrolls per month).

Non-exempt employees will continue on a bi-weekly payroll cycle. In 2017, there will be two payrolls for all months except March and September, which will have three pay periods. In 2018, there will be two payrolls for all months except March and August, which will have three pay periods.

3.6 Recruiting and Relocation Expenses

Items budgeted by HR:

- Recruiting
- Job Postings
- Testing Fees

Items budgeted by hiring organization:

- Candidate Travel Expenses
- Agency Fees
- Staff Augmentation
- Relocation Expenses

3.7 Military Leave Pay

All responsibility centers with employees incurring military pay should budget for those employees based on the updated Military Leave of Absence Policy which can be found through the pathway: Portal Home > Our Company > Policies > Human Resources

Employees are eligible to receive 100% pay for up to 80 hours for non-deployment related training. In addition, the Company will pay the difference between the employee's military pay and the Company's regular base pay for up to five years per leave for each deployment, including pre-deployment training.

3.8 Education Reimbursement (Tuition Refund) Expenses

All education reimbursement will be budgeted within the employee benefit rates. No tuition refund expenses should be budgeted within the business unit budgets unless the business unit plans to exceed established limits on graduate education reimbursement.

3.9 Dependent Care and Short Term Disability Accruals

Labor for employees on short-term disability should be budgeted by the business unit.

Accruals are established at the enterprise level as appropriate and provided to the business units to the extent they are required, per Accounting Research Group guidance.

3.10 Service and Retirement Awards

All service and retirement award gifts will be budgeted by HR and included in the employee fringe benefits load rate. The department is responsible for expenditures for any informal recognition events.

4.0 Non-Labor Budgeting

4.1 Affiliate Transactions

In certain instances (e.g., sale of Accounts Receivables and Bison Insurance), O&M budget lines should identify the affiliate business unit such that inter-company eliminations can be determined. To specify the Affiliate ID, the Supporting Detail feature within the Budgets application in Hyperion Planning will be used.

4.2 Rate Case Support

Duke Energy utilizes the budget to file rate cases for Ohio, Kentucky, and Florida. To help provide details needed to support rate requests, please consider the following:

- Budget to Accounts where actual charges will occur.
- Budget social club dues, professional dues, charitable contributions, advertising, professional services and civic/political expenses to the accounts provided below.
- Budget to the appropriate Gas vs. Electric business units where actual charges will occur.

Expense Type	Account
Social Club Dues	0926430
Professional Dues	0930210
Charitable Contributions	0426100
Advertising	On the Enterprise Budget Development SharePoint site
Professional Services	0923000
Civic/Political Expenses	0426400

4.3 Non-Labor Loading Rates

The table below contains the stores, freight, and handling rates that will be used to begin the 2017 & 2018 budgeting process.

Stores, Freight & Handling	DE Carolinas	DE Indiana	DE Ohio	DE Kentucky	DE Progress	DE Florida
Fossil / Hydro Operations	12.36%	3.50%	-	15.29%	10.52%	10.80%
Transmission & Distribution	11.5%	11.5%	11.0%	11.0%	10.0%	10.0%
Gas	-	-	6.0%	5.0%	-	-
Nuclear - Catawba	10.0%	-	-	-	-	-
Nuclear - McGuire	10.0%	-	-	-	-	-
Nuclear - Oconee	10.0%	-	-	-	-	-
Nuclear - Brunswick	-	-	-	-	10.0%	-
Nuclear - Harris	-	-	-	-	10.0%	-
Nuclear - Robinson	-	-	-	-	10.0%	-
Nuclear - Crystal River	-	-	-	-	-	15.0%

4.4 Print Services Costs

In 2017 & 2018, Print Services will charge business units (i.e. General Counsel, Commercial Business, etc.) based on actual or allocated usagefor copier use based on negotiated price per impression. The budgeted charges include impressions only. Supplies and maintenance are included in the price per impression. Administrative Services Finance will budget on behalf of the business – using the business' responsibility centers.

Departments should continue to budget for paper in 2017 & 2018.

Copy Center Services (prints, binding, etc.):
Any copy/print job created at an in house Copy Center should be budgeted by the respective Business Unit. All accounting should be provided at time of order within the myChoice Print Request tool.

Wide Format Fleet Devices –(non-Imaging Center)
Large format equipment (those at sites or specifically for Business Unit groups) is budgeted with the owner/user of equipment.

Imaging Center devices and services (prints, scans, etc.)
Any large format prints and scans created at Imaging Production Centers should be budgeted by the respective Business Unit.

If you have questions about the 2017 & 2018 Print Services budget contact Zandria Turner (704-382-3349)

4.5 Facility Costs

Corporate Offices
Budgeting responsibility for renovations to corporate office space in 2017 & 2018 will be handled by Real Estate, including office consolidations in 526 S Church St, the Duke Energy Center, 400 South Tryon, the 4th & Main/Annex in Cincinnati, and the Progress Energy Building in Raleigh.

Facility Maintenance / Additions / Changes
Real Estate will budget all building maintenance costs (i.e., janitorial services, cleaning supplies, lease payments, parking, utilities, grounds maintenance) for the corporate offices and electric/gas distribution facilities (excludes operational costs such as tools, equipment used by customer, etc.). Real Estate will budget for facility infrastructure replacements (i.e. roof, air conditioning, paving, carpet). For Real Estate questions contact:

- Fred Trammel – Midwest
- Keith Stenzler – Carolinas West
- Bobby Veit – Carolinas East
- Dawn Waldrop – Charlotte Metro
- TBD (for now Chris Arbuckle) - Florida

Additions or changes to facilities and grounds will be budgeted by the requesting department (i.e. expansion of outside storage areas, addition of access control, office renovations, furniture replacement, and new facilities) with the exception of Corporate Offices mentioned above. For pricing estimates to budget additions or changes contact:

- Chris Gilb – Midwest
- Martha B Brown/ Cathy SMedelay-Martin – Carolinas West
- Kim Bunnell – Carolinas East
- Misty Lanham/Cathy Smedelay-Martin– Charlotte Metro
- Eric Rathburn - Florida

Personnel moves that involve the movement of boxes and computers will be budgeted by the business unit unless associated with a Real Estate project. Typical rates for moves range from $75-150 for moves that occur within the same buildings, $100-175 for moves from bldg. to bldg. less than 25 miles, and $150-250 for moves greater than 25 miles. Customers requesting moves that involve reconfiguration of furniture, cubicles, keyboard trays, etc. should be budgeted within the department's budget.

Substation control house and Telecommunication building facility maintenance (i.e. plumbing, roof, air conditioning) will be budgeted by Real Estate for all locations except substations locations in Ohio/Kentucky.

Lease Administration
Real Estate is responsible for the budgeting and administration of all facility and land leases. This includes both Payable and Receivable leases. Leases are budgeted and paid internally by Real Estate using Real Estates' Responsibility Center and charged to the Operating Unit and other accounting provided by the Business Unit where the facility resides. Contact Walt Dixon (704) 382-6658 for leasing or lease administration questions.

4.6 Transportation (Fleet Services) Costs

A direct charging process is used for costs associated with all assigned vehicles and mobile (off-road) equipment. This enables Fleet Services' customers to (1) see actual costs associated with owning their vehicle and to more appropriately show the costs associated with how a particular vehicle or piece of equipment is used in their daily work, (2) create awareness of the total costs to the company for owning and operating vehicles and equipment, and (3) provide an effective management tool to use in the decision making process regarding vehicle and equipment purchases.

The direct charging process breaks down costs by ownership, repair labor, parts, fuel, commercial repair, and other miscellaneous costs. Customers can view these breakdowns by accessing the Fleet Services' Maximo customer report "Vehicle Chargeback by Level 4." You will need to get the proper security clearance to access Fleet Services customer reports in Maximo prior to viewing this report. Contact the Help Desk and press the button for Maximo Support. Ask them to open a ticket to the Fleet Services Maximo Support Team requesting them to grant you access to the Fleet Services Customer Reports. If you need further assistance in getting this access or if you have questions regarding the report, please contact Linda Price (704-382-1968).

All vehicle and mobile (off-road) equipment purchases are to be coordinated through Fleet Services. Certain mobile equipment purchases may be eligible to be funded using the customer's departmental capital accounting. Please contact Mike Allison (704-382-4750) for details and how this may affect Fleet Services chargebacks to the customer.

For 2017 budgeting purposes, all assigned vehicles and mobile equipment should be budgeted to Resource Type 50000 in the appropriate business unit budgets. This can be at a departmental level or as low as each individual responsibility center. The following guidelines may be used in determining what to budget for in the upcoming year:

(1) Take the current YTD costs in RT 50000 and annualize them; OR
(2) Run the Fleet Services' Maximo customer report " Vehicle Chargeback by Level 4" for the last 12 months. Take into consideration if units were added or reduced from the group or department and compare the result with (1) above; THEN
(3) If units are anticipated to be added in 2017 & 2018, plan on adding monies for those units. Contact the Fleet Services Customer Representative for your region to assist with determining how much to budget for these additional units (see names and contact information below).

It is essential that adequate dollars are budgeted for the vehicles and equipment assigned to your group/department as Fleet Services does not budget these dollars for you. If you need assistance with how to calculate the Fleet Services' costs for your group/department, please contact any of the following Fleet Services representatives:

Region	Contact	Phone	Email
Carolinas	Greg Sites	704-382-2320	Gregory.Sites@duke-energy.com
Florida	Jerry Shelley	407-942-9470	Jerry.Shelley@duke-energy.com

Midwest	Steve Moore	317-838-2226	Steve.Moore@duke-energy.com
All Regions	Linda Price	704-382-1968	Linda.Price@duke-energy.com

4.7 Parking Costs for Company Owned Vehicles

Each Business Unit is responsible for budgeting monthly parking costs for their company owned vehicles. The accounting below should be used to process parking costs for company owned vehicles that are parked at company owned parking facilities (Mint Street, Ohio Regional Headquarters, Florida Regional Headquarters, etc.):

Code block Element	What to charge
Responsibility Center	Business Unit Responsibility Center
Operating Unit	Business Unit Operating Unit
Process	PARK
Resource Type	69500
Account	0417007

Please contact your financial support contact for the appropriate parking accounting for non-company owned parking facilities.

4.8 Postage/Courier Services/Freight Logistics

The Administrative Services - Distribution Services group budgets for postage for routine mailings from the Corporate Mail Centers. Please use the following guidelines for specific situations:

Type of Mailing Expense	Budgeted by
Customer billing and customer bill-related mailings	User organization
Marketing related mailings	User organization
Bulk or large mailings	User organization
Employee paychecks, pension checks, incentive checks	Administrative Services - Distribution Services
Daily routing business mailings processed by Distribution Services	Administrative Services - Distribution Services
All other postage, courier, and freight-related costs – Florida	User organization
All other postage, courier, and freight-related costs – other jurisdictions	Administrative Services - Distribution Services

4.9 Research Sources, Subscriptions and Books

Type of Service	Budgeted By
Basic reference sources used by Corporate Library staff or most cost effectively maintained in central location	Administrative Services - Research Services, contact Chris Hamrick (704-382-6413)
Specialized Subscriptions/Memberships unique to a specific organization	User Organization, contact Chris Hamrick (704-382-6413) for information or cost estimate

4.10 Information Technology Budget Guidelines

The Personal Mobile Device (PMD) program is managed out of IT Customer Services. The AirWatch Technology licenses are purchased by IT. The monthly reimbursement for approved PMD program participants is provided via the expense system, meaning these costs come out of individual manager's expense budgets. $50 per month should be budgeted for each employee approved for reimbursement. You can see the 2017 & 2018 IT Planning Assumptions via the link below:

Portal Home > Work-Related Sites > Finance > Enterprise Budget Development

5.0 Capital Budgeting

5.1 Capitalization Guidelines

If you have questions regarding the capitalization policies, please contact the following:

- Mike Mc Gee for Power Production - (704) 382-8625
- Monica Kilpatrick for Land - (704) 382-9525
- Linda Miller for Software - (704) 373-2407
- Ron Foster for Power Production/Software/Land or general questions - (704) 382-8573
- Amanda Barbee for Facilities and Fleet (General Plant)- (704) 382-7623
- Krista Markel for Transmission - (980) 373-4221
- Karen Brown for Distribution (704) 382-5817
- Huyen Dang (980) 373-6482 for T&D, General Plant, Nuclear Fuel, MW/DEF Reporting, and Regulatory Accounting

To access the current Duke Energy capitalization guidelines or the Unit of Property Catalogues navigate to the following site on the Portal or click the link:

Portal Home > Work-Related Sites > Policies > Internal Controls & Finance > Property, Plant and Equipment

5.2 Capital Class definitions – Expansion, Environmental, and Maintenance

Recoverable

- Defined as items that are recovered outside of normal base rates that (1) have a specific clause/rider/tracker or (2) are deemed probable for future regulatory treatment that would result in a clause/rider/tracker.
- No or limited regulatory lag

Examples:

- DCI-DEO Rider
- AMRP & ASRP-DEO Rider
- ECRC & ECCR Clause Recovery in Florida
- Indiana Environmental Trackers
- Edwardsport Tracker

Expansion

- Would generally include projects with AFUDC that are not included in 'Recoverable' and have limited regulatory lag, or deferral opportunities. Would include projects adding MW, revenue producing projects, and acquisitions.

Examples:

- New Generation: Expenditures on projects for assets expanding generation capabilities.

- New Connects: Capital expenditures to provide lighting and metered services to new customers including dollars to achieve connection (includes new lighting installations).
- Transmission Line Expansion or major modification to accommodate new generating facilities
- Renewables

Major Projects

- Includes projects greater than $25M that are garnering AFUDC that are not in 'Recoverable' or 'Expansion'.

Example:

- Wholesale large replacement or retrofitting a plant.

Maintenance

- Includes all non-'Recoverable', non-'Expansion', and non-'Major Projects' capital.
- Maintenance would generally include minimal to no AFUDC and carries regulatory lag implications.

5.3 Capital Contingency

Project Management Center of Excellence standards require project teams to evaluate risks and establish, monitor, and report project contingency

In order to increase the transparency around budgeted contingency across the Company, all business units and corporate areas are requested to separately identify contingency by budgeting those amounts using Resource Type 94008 – Contingency.

Ideally, contingency should be cash-flowed based on the timing of the identified risks and estimates with which it is associated. If the Project is early in the development stages, and the risks have not yet been defined, it is recommended that contingency be budgeted in December or in the final month of the Project if closing prior to year end. This also applies to large O&M projects subject to PMCoE standards.

6.0 Service Company Guidelines

6.1 Charging Guidance

Costs should be directly charged to the legal entity (Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, etc.) benefiting from the services to the extent it is feasible. Otherwise, the service company allocations should be utilized.

There are three types of service company allocation pools:

- <u>Governance</u> – Corporate departments with accountability for the management of the overall function and respective issues within Duke Energy; responsible for the governance, compliance, oversight, control, audit, and strategic program design of corporate-wide activities. These costs are charged to a governance identified business unit.

- <u>Enterprise</u> – Support departments providing day-to-day services to all lines of business (e.g., IT, Corporate Facilities, Accounts Payable, HR Services); the execution of the governance process which benefits all business units. These costs are driven by and support the business, but for simplification, are allocated by the service company. These costs are charged to segment business units.

- Utility – Support departments providing day-to-day services to regulated utilities only. The execution of the governance process which only benefits the regulated utilities. These costs are driven by and support the utility businesses, but for simplification, are allocated by the service company. These costs are charged to regulated utility business units.

DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(d)

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807 KAR 5:001, SECTION 16(7)(d)

Description of Filing Requirement:

The utility's annual and monthly budget for the twelve (12) months preceding the Filing Date, the Base Period, and Forecasted Period.

Response:

See the attached for the Company's official 2017 and 2018 operating budgets which include the 12 months preceding the Filing Date (September 2016 - August 2017) and the Base Period (December 2016 - November 2017). The requested annual budget for the 12 months of the Forecasted Test Period is provided in Schedule C-1. The monthly revenue and monthly O&M amounts are shown in Work Papers WPC-2d and WPC-2.1a, respectively. This data is comprised of Duke Energy Kentucky's 2017 annual budget and extended through March 2019 as described in the testimony of Mr. Pratt.

Sponsoring Witness: Robert H. Pratt

Duke Energy Segment Reporting

DE Kentucky Electric
Dynamic Income Statement for Budget
Periodic

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Dec
	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016	2016
	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget	Budget
	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	Periodic	YTD
Operating Revenue													
Regulated Electric	30,550,772	28,621,342	27,318,469	24,651,066	25,716,890	31,614,426	31,194,474	31,302,481	27,332,263	24,834,571	24,632,212	27,858,077	335,627,042
Non-Regulated Electric, Natural Gas and Other	149,668	149,668	149,668	149,668	149,668	149,668	149,668	149,668	149,668	149,668	149,668	149,668	1,796,015
Total Operating Revenues	30,700,440	28,771,010	27,468,137	24,800,734	25,866,558	31,764,093	31,344,142	31,452,149	27,481,931	24,984,238	24,781,879	28,007,745	337,423,057
Operating Expenses													
Fuel used in Electric Generation and Purchased Power	11,059,241	10,169,423	10,303,899	8,639,237	9,181,669	12,336,583	10,706,578	11,185,272	10,276,027	8,910,758	9,008,200	10,005,333	121,782,220
Operations, Maintenance and Other	7,934,073	8,160,604	9,319,786	11,445,720	8,050,304	7,729,383	8,301,830	8,869,382	8,732,248	8,939,389	8,692,765	8,769,118	104,944,602
Depreciation and Amortization	2,652,820	2,655,004	2,654,828	2,783,542	2,787,004	2,791,411	2,798,798	2,794,851	2,776,785	2,782,344	2,786,996	2,735,291	32,999,674
Property and Other Taxes	794,097	777,427	784,603	808,726	786,101	783,159	789,090	788,629	814,689	792,259	790,305	786,653	9,495,738
Total Operating Expenses	22,440,232	21,762,459	23,063,115	23,677,225	20,805,079	23,640,536	22,596,296	23,638,134	22,599,749	21,424,749	21,278,266	22,296,396	269,222,235
Operating Income	8,260,207	7,008,551	4,405,022	1,123,509	5,061,479	8,123,557	8,747,846	7,814,015	4,882,182	3,559,490	3,503,614	5,711,349	68,200,822
Other Income and Expenses													
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred	162,268	176,458	110,896	45,715	54,565	62,560	77,772	93,723	107,077	122,158	139,627	134,627	1,287,446
7310_INT_DIV - Interest and Dividends	3,169	625	625	625	625	625	625	625	625	625	625	625	10,044
7330_INTERCO_INT - Intercompany Interest Income	108,942	152,962	132,857	93,590	76,708	68,824	70,654	82,283	86,825	95,211	103,052	98,322	1,170,231
Other Income and Expenses	274,380	330,045	244,377	139,929	131,899	132,009	149,051	176,631	194,527	217,994	243,305	233,574	2,467,721
Earnings Before Interest Expense and Taxes	8,534,587	7,338,596	4,649,400	1,263,438	5,193,378	8,255,566	8,896,897	7,990,646	5,076,709	3,777,484	3,746,918	5,944,923	70,668,543
Interest Expense	1,065,132	1,049,217	967,407	932,709	893,135	926,092	911,112	868,502	904,000	943,199	957,779	962,379	11,380,663
Earnings From Continuing Operations Before Income Taxes	7,469,454	6,289,380	3,681,993	330,729	4,300,243	7,329,474	7,985,785	7,122,144	4,172,709	2,834,285	2,789,139	4,982,544	59,287,880
Income Tax Expense (Benefit) From Continuing Operations	2,754,851	2,314,185	1,390,859	127,195	1,613,707	2,712,640	3,050,606	2,709,776	1,551,001	1,003,474	987,782	1,864,742	22,080,817
Income From Continuing Operations Attributable to Duke E	4,714,604	3,975,195	2,291,134	203,534	2,686,536	4,616,834	4,935,179	4,412,369	2,621,708	1,830,811	1,801,357	3,117,802	37,207,063
Income (Loss) From Continuing Operations	4,714,604	3,975,195	2,291,134	203,534	2,686,536	4,616,834	4,935,179	4,412,369	2,621,708	1,830,811	1,801,357	3,117,802	37,207,063
Net Inc Bfr Ext and Chg in Acct. Prin.	4,714,604	3,975,195	2,291,134	203,534	2,686,536	4,616,834	4,935,179	4,412,369	2,621,708	1,830,811	1,801,357	3,117,802	37,207,063

Duke Energy Segment Reporting

DE Kentucky Electric
Dynamic Income Statement for Budget
Periodic

	Jan 2016 Budget Periodic	Feb 2016 Budget Periodic	Mar 2016 Budget Periodic	Apr 2016 Budget Periodic	May 2016 Budget Periodic	Jun 2016 Budget Periodic	Jul 2016 Budget Periodic	Aug 2016 Budget Periodic	Sep 2016 Budget Periodic	Oct 2016 Budget Periodic	Nov 2016 Budget Periodic	Dec 2016 Budget Periodic	Dec 2016 Budget YTD
Consolidated Net Income	4,714,604	3,975,195	2,291,134	203,534	2,686,536	4,616,834	4,935,179	4,412,369	2,621,708	1,830,811	1,801,357	3,117,802	37,207,063
Less: Net Income (Loss) attributable to non controlling interes	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income Attributable to Controlling Interests	4,714,604	3,975,195	2,291,134	203,534	2,686,536	4,616,834	4,935,179	4,412,369	2,621,708	1,830,811	1,801,357	3,117,802	37,207,063

Duke Energy Segment Reporting

DE Kentucky Electric
Dynamic Income Statement for Budget
Periodic

	Jan 2017 Budget Periodic	Feb 2017 Budget Periodic	Mar 2017 Budget Periodic	Apr 2017 Budget Periodic	May 2017 Budget Periodic	Jun 2017 Budget Periodic	Jul 2017 Budget Periodic	Aug 2017 Budget Periodic	Sep 2017 Budget Periodic	Oct 2017 Budget Periodic	Nov 2017 Budget Periodic	Dec 2017 Budget Periodic	Dec 2017 Budget YTD
Operating Revenue													
Regulated Electric	28,653,601	27,248,839	29,141,516	28,178,653	24,979,987	28,410,456	31,297,033	29,948,133	26,286,549	25,009,049	24,752,538	27,648,119	331,554,473
Non-Regulated Electric, Natural Gas and Other	41,860	41,860	41,860	41,860	41,860	41,860	41,860	41,860	41,860	375,193	375,193	375,193	1,502,320
Total Operating Revenues	28,695,461	27,290,699	29,183,376	28,220,513	25,021,847	28,452,316	31,338,893	29,989,993	26,328,409	25,384,243	25,127,732	28,023,313	333,056,793
Operating Expenses													
Fuel used in Electric Generation and Purchased Power	10,238,394	10,104,026	11,868,460	9,036,942	8,738,509	9,775,442	11,091,390	10,554,391	9,893,492	8,870,045	8,504,324	9,150,446	117,825,859
Operations, Maintenance and Other	9,003,284	8,676,382	10,194,192	9,613,362	8,743,749	8,272,486	8,678,442	8,385,645	7,809,259	8,248,145	8,601,756	10,021,504	106,248,207
Depreciation and Amortization	2,942,789	2,944,497	2,946,398	3,208,925	3,206,031	3,206,894	3,258,499	3,222,607	3,207,595	3,269,084	3,284,169	3,303,398	38,000,886
Property and Other Taxes	916,238	901,721	932,575	908,714	898,947	901,818	901,566	899,888	926,112	907,095	901,286	903,044	10,899,005
Total Operating Expenses	23,100,705	22,626,625	25,941,626	22,767,943	21,587,236	22,156,641	23,929,897	23,062,531	21,836,458	21,294,369	21,291,535	23,378,392	272,973,956
Operating Income	5,594,756	4,664,074	3,241,750	5,452,570	3,434,612	6,295,675	7,408,995	6,927,461	4,491,951	4,089,874	3,836,197	4,644,921	60,082,837
Other Income and Expenses													
Gain (Loss) \ Impairment - Equity of Affiliates	-	-	(1,400,000)	-	-	-	-	-	-	-	-	-	(1,400,000)
7311_AFUDC_OTH_DF_RT - AFUDC and Other Deferred	163,516	194,516	111,536	39,427	90,239	110,965	122,771	158,400	176,173	192,702	235,959	225,522	1,821,727
7310_INT_DIV - Interest and Dividends	2,331	625	625	625	625	625	625	625	625	625	625	625	9,206
7330_INTERCO_INT - Intercompany Interest Income	108,089	116,265	103,353	83,427	75,934	94,439	104,164	106,593	99,326	88,200	85,522	95,678	1,160,991
Other Income and Expenses	273,936	311,407	(1,184,486)	123,479	166,798	206,029	227,559	265,618	276,125	281,527	322,106	321,825	1,591,923
Earnings Before Interest Expense and Taxes	5,868,693	4,975,480	2,057,264	5,576,050	3,601,410	6,501,704	7,636,554	7,193,080	4,768,076	4,371,401	4,158,302	4,966,746	61,674,760
Interest Expense	760,835	726,344	786,403	821,383	855,314	971,133	951,138	900,658	936,377	910,757	857,025	901,013	10,378,380
Earnings From Continuing Operations Before Income Taxes	5,107,857	4,249,136	1,270,861	4,754,666	2,746,095	5,530,571	6,685,416	6,292,422	3,831,698	3,460,645	3,301,278	4,065,734	51,296,380
Income Tax Expense (Benefit) From Continuing Operations	1,917,767	1,575,453	489,554	1,829,669	1,037,334	2,015,670	2,540,417	2,375,537	1,381,951	1,272,831	1,194,873	1,589,008	19,220,094
Income From Continuing Operations Attributable to Duke E	3,190,090	2,673,684	781,307	2,924,997	1,708,761	3,514,901	4,144,969	3,916,885	2,449,748	2,187,814	2,106,405	2,476,726	32,076,285
Income (Loss) From Continuing Operations	3,190,090	2,673,684	781,307	2,924,997	1,708,761	3,514,901	4,144,969	3,916,885	2,449,748	2,187,814	2,106,405	2,476,726	32,076,285
Net Inc Bfr Ext and Chg in Acct. Prin.	3,190,090	2,673,684	781,307	2,924,997	1,708,761	3,514,901	4,144,969	3,916,885	2,449,748	2,187,814	2,106,405	2,476,726	32,076,285

Duke Energy Segment Reporting

DE Kentucky Electric
Dynamic Income Statement for Budget
Periodic

	Jan 2017 Budget Periodic	Feb 2017 Budget Periodic	Mar 2017 Budget Periodic	Apr 2017 Budget Periodic	May 2017 Budget Periodic	Jun 2017 Budget Periodic	Jul 2017 Budget Periodic	Aug 2017 Budget Periodic	Sep 2017 Budget Periodic	Oct 2017 Budget Periodic	Nov 2017 Budget Periodic	Dec 2017 Budget Periodic	Dec 2017 Budget YTD
Consolidated Net Income	3,190,090	2,673,684	781,307	2,924,997	1,708,761	3,514,901	4,144,969	3,916,885	2,449,748	2,187,814	2,106,405	2,476,726	32,076,285
Less: Net Income (Loss) attributable to non controlling interes	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Income Attributable to Controlling Interests	3,190,090	2,673,684	781,307	2,924,997	1,708,761	3,514,901	4,144,969	3,916,885	2,449,748	2,187,814	2,106,405	2,476,726	32,076,285

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(e)

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807 KAR 5:001, SECTION 16(7)(e)

Description of Filing Requirement:

A statement of attestation signed by the utility's chief officer in charge of Kentucky operations which shall provide:

(1) that the forecast is reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified;

(2) that the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist; and

(3) that productivity and efficiency gains are included in the forecast.

Response:

See attached.

Sponsoring Witness: James P. Henning

AFFIDAVIT OF JAMES P. HENNING

STATE OF OHIO)
)
COUNTY OF HAMILTON)

Now comes James P. Henning, President of Duke Energy Kentucky, Inc. and as required by 807 KAR 5:001, Section 16(7)(e), hereby attests as follows:

1. the forecast used in this rate application is reasonable, reliable, made in good faith and that all basic assumptions used in the forecast have been identified and justified;
2. the forecast contains the same assumptions and methodologies as used in the forecast prepared for use by management, or an identification and explanation for any differences that exist; and
3. productivity and efficiency gains are included in the forecast.

Further affiant sayeth naught.

James P. Henning, Affiant

Sworn and subscribed before me by James P. Henning on this 18th day of August 2017.

Notary Public

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(f)(1) through (4)

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807 KAR 5:001, SECTION 16(7)(f)(1) through (4)

Description of Filing Requirement:

For each major construction project which constitutes five (5) percent or more of the annual construction budget within the three (3) year forecast the following information shall be filed:

(1) The date the project was started or estimated starting date;

(2) The estimated completion date;

(3) The 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) The most recent available total costs incurred exclusive and inclusive of AFUDC or interest during construction credit.

Response:

See attached.

Sponsoring Witness: Robert H. Pratt / Joseph A. Miller / Anthony J. Platz

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Major Construction Projects
Constituting 5% or More of Annual Budget

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2017	Estimated Costs Including AFUDC 2018	Estimated Costs Including AFUDC 2019	Estimated Costs Excluding AFUDC 2017	Estimated Costs Excluding AFUDC 2018	Estimated Costs Excluding AFUDC 2019	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	WD101209 - WGS CT 1 Overhaul #2	12/1/2011	10/31/2017	7,314,540	0	0	7,107,322	0	0	3,160,770	3,073,087
2	EB021422 - Precipitator Rebuild	1/1/2016	12/31/2018	8,749,392	26,224,855	0	8,509,235	24,780,336	0	627,694	598,889
3	WDC00004 - Install Fuel Oil System	8/1/2016	12/31/2019	3,366,990	36,621,265	15,000,000	3,300,001	35,307,449	15,000,000	160,162	158,336
4	EB020578 - East Bend 2 Dual Fuel Cofiring	1/1/2017	12/31/2020	1,543,412	2,141,357	4,013,122	1,500,000	2,081,547	3,900,800	-	-
5	EB020290 - Lined Retention Basin WEST	8/1/2016	3/31/2019	736,539	19,089,303	240,014	703,368 0	18,572,079 0	240,014	1,025,696	1,012,282
6	EB020745 - Lined Retention Basin EAST	10/1/2018	3/31/2021	0	75,313	4,092,541	0 0	75,000 0	4,053,028	-	-
7	EB020298 - East Bend SW / PW REROUTE	8/1/2016	3/31/2019	6,656,571	14,671,999	305,047	6,554,270 0	13,990,195 0	305,047	970,733	956,037
8	EB021281 - New East Bend Landfill Ph 2 of 8	6/1/2017	12/31/2021	1,052,812 0	2,512,716 0	12,522,926	1,036,000 0	2,355,732 0	11,865,280	-	-
9	EB021410 - Dry Bottom Ash Conversion	12/1/2015	4/30/2018	8,346,702 0	9,739,344	0	8,086,716 0	9,527,817 0	0	1,623,170	1,591,867
10	EBS01243 - New East Bend Landfill Ph 1 of 8	12/1/2013	12/31/2017	17,053,446	0	0	14,799,505 0	0 0	0	27,216,024	26,484,314
11	Advanced Metering Infrastructure	2/1/2017	11/30/2018	11,134,409 0	12,305,233	0	11,130,625	12,303,392	0	-	-
12	Solar Generation Facilities	10/1/2016	3/31/2018	13,431,325	1,160,870	0	13,338,733	1,160,870	0	34,936	34,936

Note: Duke Energy Kentucky, Inc.'s normal practice is to forecast AFUDC at a summarized level, with certain similar projects combined for forecasting purposes.
AFUDC amounts in this schedule represent estimates related to these specific projects.

DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(g)

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807 KAR 5:001, SECTION 16(7)(g)

Description of Filing Requirement:

For all construction projects which constitute less than five (5) percent of the annual construction budget within the three (3) year forecast, the utility shall file an aggregate of the information requested in paragraph (f) 3 and 4 of this subsection.

Response:

See attached.

Sponsoring Witness: Robert H. Pratt / Joseph A. Miller / Anthony J. Platz

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Major Construction Projects
Constituting Less than 5% of Annual Budget

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs Including AFUDC 2017	Estimated Costs Including AFUDC 2018	Estimated Costs Including AFUDC 2019	Estimated Costs Excluding AFUDC 2017	Estimated Costs Excluding AFUDC 2018	Estimated Costs Excluding AFUDC 2019	Actual Costs To Date incl AFUDC	Actual Costs To Date excl AFUDC
1	Sum of all projects not included on 7(f)	Various	Various	55,553,005	76,249,194	40,725,309	54,763,805	75,058,798	40,471,141	18,729,420	11,969,309

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(h)

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807 KAR 5:001, SECTION 16(7)(h)

Description of Filing Requirement:

A financial forecast corresponding to each of the three (3) forecasted years included in the capital construction budget. The financial forecast shall be supported by the underlying assumptions made in projecting the results of operations and shall include 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, if applicable.

Response:

Items 6, 13, 14, 16, and 17 are not applicable. For all other items, see attached.

Sponsoring Witnesses:

Robert H. Pratt – (Items 1, 2, 3, 4, 8, 9, 10, 12, 15)
Robert H. Pratt / Benjamin Passty – (Item 5)
John Verderame – (Item 7)
John L. Sullivan, III – (Item 11)

FR 16(7)(h)(1)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Projected Income Statement 2017-2019

Line No.	Description	2017	2018	2019
1	Operating Revenue			
2	Electric Revenue	$ 330,436,793	$ 326,082,407	$ 322,276,396
3	Gas Revenue	96,646,230	97,634,986	115,672,540
4	Other Revenue	1,220,000	220,000	220,000
5	Total Operating Revenue	$ 428,303,023	$ 423,937,393	$ 438,168,936
6	Operating Expenses			
7	Fuel & Purchased Power	$ 117,825,859	$ 115,924,404	$ 113,241,543
8	Gas Purchased	39,110,139	38,193,071	38,514,133
9	Operation & Maintenance	134,812,034	151,658,873	147,566,790
10	Depreciation & Amortization	49,044,141	63,805,233	69,279,374
11	Taxes Other Than Income	14,395,228	15,993,098	18,688,545
12	Operating Expenses before Income Tax	$ 355,187,401	$ 385,574,679	$ 387,290,385
13	Pre-Tax Operating Income	$ 73,115,622	$ 38,362,714	$ 50,878,551
14	Other Income	$ 3,768,715	$ 5,314,779	$ 2,157,800
15	Interest Expense	$ 13,771,742	$ 18,663,244	$ 21,815,365
16	State Income Taxes	$ 3,295,509	$ 1,171,623	$ 1,687,146
17	Federal Income Taxes	20,117,425	7,136,710	10,209,574
18	Total Income Taxes	$ 23,412,934	$ 8,308,333	$ 11,896,720
19	Income Available for Common Dividends	$ 39,699,661	$ 16,705,916	$ 19,324,266
20	Average Common Equity	$ 461,861,130	$ 519,813,919	$ 555,329,009
21	Earned Return	8.60%	3.21%	3.48%

FR 16(7)(h)(2)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Projected Balance Sheet 2017-2019

Line No.	Description	2017	2018	2019
1	**Assets**			
2	Utility plant in service	$ 2,218,734,753	$ 2,467,756,157	$ 2,533,991,188
3	Construction work in progress	54,000,402	26,198,349	46,019,876
4	Total Utility Plant	$ 2,272,735,155	$ 2,493,954,506	$ 2,580,011,064
5	Non-regulated property, plant, and equipment	$ 2,206	$ 2,206	$ 2,206
6	Accumulated depreciation	975,734,138	1,010,439,315	1,049,092,409
7	Net Property, Plant, and Equipment	$ 1,297,003,223	$ 1,483,517,397	$ 1,530,920,861
8	Current Assets	$ 110,871,702	$ 99,458,615	$ 94,685,059
9	Other Assets	$ 120,966,042	$ 120,814,642	$ 127,125,324
10	Total Assets	$ 1,528,840,967	$ 1,703,790,654	$ 1,752,731,244
	Liabilities			
11	Total Current Liabilities	$ 92,150,331	$ 193,007,118	$ 101,739,702
12	Long-term debt	451,576,284	520,839,539	525,190,007
13	Accumulated deferred income taxes	354,626,522	403,840,840	431,866,420
14	Unamortized investment tax credits	5,035,347	5,035,347	5,035,347
15	Other	138,741,522	28,150,932	131,158,625
16	Total Non-Current Liabilities	$ 949,979,675	$ 957,866,658	$ 1,093,250,399
17	Total Common Stock Equity	486,710,962	552,916,876	557,741,142
18	Total Liabilities	$ 1,528,840,968	$ 1,703,790,652	$ 1,752,731,243

FR 16(7)(h)(3)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Projected Cash Flow Statement 2017-2019

Line No.	Description	2017	2018	2019
1	Net Income	$ 39,699,661	$ 16,705,916	$ 19,324,266
2	Other Operating Activities	59,777,892	93,378,502	90,244,502
3	Cash from Operating Activities	$ 99,477,553	$ 110,084,418	$ 109,568,768
4	Financing Activities			
5	Change in contributed capital	$ 10,000,000	$ 49,500,000	$ (14,500,000)
6	Change in short-term debt	(19,656,000)	-	-
7	Issuance of long-term debt	90,000,000	70,000,000	104,500,000
8	Change in non-current capital leases			
9	Redemption of long-term debt	(655,023)	(921,776)	(100,314,700)
10	Dividends on common stock			
11	Cash from Financing Actitivies	$ 79,688,977	$ 118,578,224	$ (10,314,700)
12	Investing Activities			
13	Construction Expenditures (net of AFUDC)	$ (170,587,741)	$ (234,506,098)	$ (102,771,399)
14	Acquisitions and other investments	793,045	3,042	10,573
15	Cash from Investing Actitivies	$ (169,794,696)	$ (234,503,056)	$ (102,760,826)
16	Net Increase/(Decrease) in Cash	$ 9,371,834	$ (5,840,414)	$ (3,506,758)

FR 16(7)(h)(4)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Revenue Requirements 2017-2019

Line No.	Description	2017	2018	2019
1	Capitalization Allocated to Electric Operations	$ 682,705,566	$ 799,787,721	$ 802,757,920
2	Operating Income	$ 38,904,219	$ 16,750,374	$ 15,327,982
3	Earned Rate of Return (Line 2 / Line 1)	5.700%	2.100%	1.900%
4	Rate of Return	7.208%	7.092%	7.092%
5	Required Operating Income (Line 1 x Line 4)	$ 49,209,417	$ 56,720,945	$ 56,931,592
6	Operating Income Deficiency (Line 5 - Line 2)	$ 10,305,198	$ 39,970,571	$ 41,603,610
7	Gross Revenue Conversion Factor	1.6298147	1.6298147	1.6298147
8	Revenue Deficiency (Line 6 x Line 7)	$ 16,795,563	$ 65,144,624	$ 67,806,175

FR 16(7)(h)(5)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Load Forecast 2017-2019

Line No.	Description	2017	2018	2019
1	KW Demand - Coincident Peak			
2				
3	January	742,056	740,448	736,748
4	February	696,848	696,650	691,922
5	March	614,684	614,716	610,342
6	April	554,864	555,663	551,977
7	May	712,106	712,492	709,268
8	June	808,659	808,287	805,403
9	July	836,088	830,425	833,670
10	August	819,739	813,635	816,948
11	September	806,722	800,473	803,731
12	October	605,347	597,266	600,175
13	November	614,173	605,827	608,357
14	December	663,532	654,233	656,716
15				
16	KWH Sales			
17				
18	January	374,404,251	378,494,485	379,322,548
19	February	335,543,242	353,286,320	355,911,599
20	March	275,990,565	286,508,562	288,196,044
21	April	274,949,937	285,473,154	278,290,580
22	May	295,456,777	287,850,763	299,356,025
23	June	347,378,963	352,998,969	355,501,230
24	July	401,372,263	404,139,437	404,733,395
25	August	364,057,286	363,707,154	363,405,622
26	September	371,125,008	375,323,317	376,089,067
27	October	329,331,732	328,154,578	326,238,829
28	November	296,726,241	298,820,079	296,706,464
29	December	365,338,063	367,893,824	366,257,814

FR 16(7)(h)(7)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Mix of Generation 2017-2019

Line No.	Description	2017	2018	2019
1	Coal	3,721,791	3,024,817	3,622,135
2	Natural Gas	19,216	18,371	18,883
3	Oil	0	0	0
4	Total Generation (MWH)	3,741,007	3,043,188	3,641,018

16(7)(h)(8)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Mix of Gas Supply 2017-2019

Line No.	Description	2017	2018	2019
1	Columbia Gas Trans - No Notice	960,049	960,049	960,049
2	Undetermined	8,393,384	8,479,328	8,570,366
3	Propane - Air	31,000	31,000	31,000
4	Total Supply - MCF	9,384,433	9,470,377	9,561,415
5	Columbia Gas Trans - No Notice	$ 3,492,771	$ 3,186,250	$ 3,024,324
6	Undetermined	28,961,000	28,650,786	28,654,434
7	Propane - Air	448,652	448,652	448,652
8	Demand Costs	7,254,386	7,327,281	7,551,748
9	Total Cost	$ 40,156,809	$ 39,612,969	$ 39,679,158

FR 16(7)(h)(9)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Number of Employees 2017-2019

Line No.	Description	2017	2018	2019
1	Number of employees	185	185	185

This count includes only direct employees of Duke Energy Kentucky, Inc..

FR 16(7)(h)(10)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Labor Cost Changes 2017-2019

Line No.	Description	2017	2018	2019
1	Total Labor Costs:			
2				
3	Gas O&M Expense	$ 11,397,519	$ 11,531,466	$ 11,646,781
4	Electric O&M Expense	40,381,212	38,515,330	38,900,483
5	Total O&M	$ 51,778,731	$ 50,046,796	$ 50,547,264
6				
7	Gas Capital	$ 7,529,358	$ 6,680,345	$ 6,747,148
8	Electric Capital	14,749,358	12,965,111	13,094,762
9	Non-jurisdictional Capital	0	0	0
10	Total Capital	$ 22,278,716	$ 19,645,456	$ 19,841,910
11				
12	Total	$ 74,057,447	$ 69,692,252	$ 70,389,174

* Includes benefits & incentives (direct & allocated).

FR 16(7)(h)(11)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Capital Structure Requirements 2017-2019

Line No.	Description	2017		2018		2019
		$	%	$	%	$
1	Common Equity	486,710,962	50.236%	552,916,876	50.069%	557,741,142
2	Long-term Debt	451,576,284	46.610%	520,839,539	47.164%	525,190,007
3	Short-term Debt	30,556,687	3.154%	30,556,687	2.767%	30,556,687
4	Total Capital	968,843,933	100.00%	1,104,313,102	100.00%	1,113,487,836

FR 16(7)(h)(12)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Rate Base 2017-2019

Line No.	Description	2017	2018	2019
1	Adjusted Jurisdictional Plant in Service	$ 1,700,531,365	$ 1,916,251,916	$ 1,960,119,585
2	Accumulated Depreciation and Amortization	(814,267,402)	(839,379,170)	(867,870,527)
3	Net Plant in Service (Line 1 + Line 2)	$ 886,263,963	$ 1,076,872,746	$ 1,092,249,058
4	Construction Work in Progress	44,999,234	14,855,127	32,635,714
5	Cash Working Capital Allowance	13,515,444	15,981,459	15,319,285
6	Other Working Capital Allowances	40,471,626	40,471,626	40,471,626
7	Other Items:			
8	Customers' Advances for Construction	0	0	0
9	Investment Tax Credits	(4,397,166)	(4,397,166)	(4,397,166)
10	Deferred Income Taxes	(270,830,785)	(313,069,742)	(335,751,099)
11	Other Rate Base Adjustments	0	0	0
12	Jurisdictional Rate Base (Line 3 through Line 11)	$ 710,022,316	$830,714,050	$ 840,527,418

FR 16(7)(h)(14)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Customer Forecast 2017-2019

Line No.	Description	2017	2018	2019
1	Residential	125,085	125,643	126,252
2	Commercial	14,057	14,106	14,138
3	Industrial	367	365	362
4	Other	1,381	1,377	1,379
5	Total Electric Retail	140,890	141,491	142,131
6	Residential	91,744	92,474	93,077
7	Commercial	7,412	7,468	7,485
8	Industrial	211	210	209
9	Other	370	372	375
10	Total Full Requirements	99,737	100,524	101,146
11				
12	Transportation			
13	Commercial	82	83	83
14	Industrial	52	51	51
15	Other	16	16	17
16	Total Transportation	150	150	151
17				
18	Total Gas Retail (Line 10 + Line 16)	99,887	100,674	101,297

16(7)(h)(15)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
MCF Sales Forecast 2017-2019

Line No.	Description	2017	2018	2019
1	Residential	5,881,326	5,998,071	6,052,019
2	Commercial	2,951,550	2,984,514	2,984,231
3	Industrial	190,388	195,003	197,722
4	Other	357,102	359,587	359,783
5	Interdepartmental	4,506	4,492	4,453
6	Total Retail	9,384,872	9,541,667	9,598,208
7	Transportation			
8	Commercial	493,839	499,354	499,307
9	Industrial	1,652,078	1,692,115	1,715,737
10	Other	1,599,049	1,616,756	1,629,046
11	Total Transportation	3,744,966	3,808,225	3,844,090
12	Total MCF Sales	13,129,838	13,349,892	13,442,298

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DUKE ENERGY KENTUCKY
CASE NO. 2017-00321
FORECASTED TEST PERIOD FILING REQUIREMENTS
FR 16(7)(i)

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807 KAR 5:001, SECTION 16(7)(i)

Description of Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports.

Response:

See attached.

Witness Responsible: David L. Doss, Jr.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. PA14-2-000
April 1, 2016

Duke Energy Corporation
Attention: Mr. Brian D. Savoy
Senior Vice President, Chief Accounting
Officer and Controller
550 South Tryon St.
Charlotte, NC 28202

Dear Mr. Savoy:

1. The Division of Audits and Accounting (DAA) within the Office of Enforcement (OE) of the Federal Energy Regulatory Commission (Commission) has completed an audit of Duke Energy Corporation (Duke Energy) and its public utility subsidiaries. The audit covered the period from January 1, 2011 through January 31, 2016.

2. The audit evaluated Duke Energy's compliance with conditions and requirements established in Commission orders authorizing the merger of Duke Energy and Progress Energy, Inc. The audit also evaluated each Duke Energy public utility subsidiary's compliance with: (1) tariff requirements governing its transmission formula rate; (2) accounting regulations in 18 C.F.R. Part 101, Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act; and (3) financial reporting regulations in 18 C.F.R. Part 141, Statements and Reports. The enclosed audit report contains eight findings and 37 recommendations that require Duke Energy to take corrective action.

3. On March 30, 2016, you notified DAA that Duke Energy does not contest the audit report or any of its recommendations. A copy of your verbatim response is included as an appendix to this report. I hereby approve the audit report.

4. Duke Energy should submit its implementation plan to comply with the recommendations within 30 days of this letter order. Duke Energy should make quarterly submissions to DAA describing the progress made to comply with the recommendations, including the completion date for each corrective action. As directed by the audit report, these submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after this audit report is issued, and continuing until all the corrective actions are completed.

5. The Commission delegated authority to act on this matter to the Director of OE under 18 C.F.R. § 375.311 (2015). This letter order constitutes final agency action. Duke Energy may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2015).

6. This letter order is without prejudice to the Commission's right to require hereafter any adjustments it may consider proper from additional information that may come to its attention. In addition, any instance of noncompliance not addressed herein or that may occur in the future may also be subject to investigation and appropriate remedies.

7. I appreciate the courtesies extended to the auditors. If you have any questions, please contact Mr. Bryan K. Craig, Director and Chief Accountant, Division of Audits and Accounting at (202) 502-8741.

Sincerely,

Larry R. Parkinson
Director
Office of Enforcement

Enclosure

Federal Energy Regulatory Commission
Office of Enforcement
Division of Audits and Accounting

AUDIT REPORT

Audit of Duke Energy Corporation and its Public Utility Subsidiaries' Compliance with:

- Conditions in Commission Merger Authorization Orders;
- Transmission Formula Rate Tariff Requirements; and
- Accounting and Financial Reporting Regulations.

Docket No. PA14-2-000
March 29, 2016

Table of Contents

I. Executive Summary

A. Overview

The Division of Audits and Accounting (DAA) in the Office of Enforcement has completed an audit of Duke Energy Corporation (Duke Energy) and its public utility subsidiaries'[1] (collectively, Duke Companies) compliance with conditions and requirements established in Commission orders authorizing the merger of Duke Energy and Progress Energy, Inc. (Progress Energy).[2] The audit also evaluated each Duke Energy public utility subsidiary's compliance with: (1) tariff requirements governing its transmission formula rate; (2) accounting regulations in 18 C.F.R. Part 101, Uniform System of Accounts (USofA) Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act; and (3) financial reporting regulations in 18 C.F.R. Part 141, Statements and Reports. The audit covered the period January 1, 2011 through January 31, 2016.

B. Duke Energy Corporation

Duke Energy is a public utility holding company headquartered in Charlotte, NC. It is engaged in energy production, trade, transmission, and distribution through its six public utility subsidiaries that operate in the Southeast and Midwest regions of the United States. In 2014, Duke Energy was the largest electric utility in the nation. The company had 7.3 million retail electric and 500,000 natural gas customers, 32,400 miles of transmission lines, 57,500 MW of generating capacity, and total operating revenue of $23.9 billion. Its service area covered about 95,000 square miles and had an estimated population of 23 million. Regulated operations accounted for over 90 percent of the company's total revenue, and commercial power generation and international operations provided most of the remainder.

[1] The Duke Energy public utility subsidiaries are: Duke Energy Carolinas, LLC (DEC), Duke Energy Progress, LLC (DEP), Duke Energy Florida, LLC (DEF), Duke Energy Indiana, LLC (DEI), Duke Energy Ohio, Inc. (DEO), and Duke Energy Kentucky, Inc. (DEK).

[2] *Duke Energy Corp. and Progress Energy, Inc.*, 136 FERC ¶ 61,245 (2011) (Merger Order), *order on compliance*, 137 FERC ¶ 61,210 (2011), *order on compliance*, 139 FERC ¶ 61,194 (2012) (June 8 Compliance Order), *order on compliance*, 149 FERC ¶ 61,078 (2014) (October 29 Compliance Order).

C. Summary of Compliance Findings

Audit staff identified eight findings of noncompliance. Below is a summary of audit staff's compliance findings. Details are in section IV of this report.

- *Accounting for Merger Transaction Costs* – Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

- *Merger Transaction Internal Labor Costs* – Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million.

- *Merger Transaction Outside Services and Related Costs* – Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $745,000.

- *Use of the Consolidation Method of Accounting* – DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their FERC Form No. 1, Annual Reports (Form No. 1), contrary to the Commission's long-standing accounting policy.

- *Accounting for Sales of Accounts Receivable* – DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

- *Accounting for Lobbying Expenses:* Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 through 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

- *Allocation of Lobbyist Labor Costs:* Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

- *Nonutility Expenses in Operating Accounts:* Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

D. Summary of Recommendations

Audit staff's recommendations to remedy the findings are summarized below with details in section IV of this report. Audit staff recommends that Duke Companies:

Accounting for Merger Transaction Costs

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

Merger Transaction Internal Labor Costs

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Merger Transaction Outside Services and Related Costs

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Use of the Consolidation Method of Accounting

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

Accounting for Sales of Accounts Receivable

17. Revise procedures to ensure that all costs and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all losses associated with receivable sales are recorded in Account 426.5.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be

made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Accounting for Lobbying Expenses

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying cost in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Allocation of Lobbyist Labor Costs

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support

staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of the date of the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

30. Implement policies and procedures to perform a labor time study biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

Nonutility Expenses in Operating Accounts

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to administrative and general (A&G) accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

35. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

E. Implementation of Recommendations

Audit staff further recommends that Duke Companies submit the following for audit staff's review:

- A plan for implementing the audit recommendations within 30 days after the final audit report is issued;

- Quarterly reports describing progress in completing each corrective action recommended in the final audit report. Quarterly nonpublic submissions should be made no later than 30 days after the end of each calendar quarter, beginning with the first quarter after the final audit report is issued, and continuing until all recommended corrective actions are completed; and

- Copies of any written policies and procedures developed in response to recommendations in the audit report. These documents should be submitted in the first quarterly filing after Duke Companies complete such policies and procedures.

II. Background

A. Merger of Duke Energy and Progress Energy

On January 10, 2011, Duke Energy and Progress Energy announced their intention to merge in a stock-for-stock transaction under which Progress Energy would become a wholly owned subsidiary of Duke Energy, and the shareholders of Progress Energy would become shareholders of Duke Energy. At the time, the transaction was valued at over $31 billion. The merger was poised to create the largest U.S. electric utility in history with over seven million electric customers and operations in six states.

Following the announcement, on April 4, 2011, Duke Energy, Progress Energy, and their public utility subsidiaries (collectively, Duke Companies) filed an application with the Commission seeking authorization for the merger transaction under section 203 of the Federal Power Act (FPA)[3] and Part 33 of Commission regulations.[4] To receive authorization for the transaction, the companies committed to hold transmission and wholesale requirements customers harmless from the costs of the transaction for five years. The companies also contended that the transaction would not adversely affect competition, and thus there were no market power concerns associated with the transaction.

On September 30, 2011, the Commission found that the transaction, as proposed in the application, would result in significant screen failures in the horizontal market power analysis and have an adverse effect on competition.[5] As such, the Commission authorized the transaction subject to conditions. Among other things, the transaction was conditioned on Duke Companies holding transmission and wholesale requirements customers harmless from the costs of the transaction, and submitting proposed market power mitigation measures that the Commission approves. The Commission advised Duke Companies that sufficient mitigation measures could include membership in a regional transmission organization, implementing an independent coordinator of transmission arrangement, actual or virtual divestiture of generation, and/or transmission upgrades to provide greater market access to third-party energy suppliers.

Further, the Commission stated that the hold harmless commitment included all merger transaction costs, not only costs related to consummating the transaction.[6] To recover merger transaction costs through wholesale requirement or transmission rates, the

[3] 16 U.S.C. § 824b (2012).

[4] 18 C.F.R. Part 33.

[5] Merger Order, 136 FERC ¶ 61,245 at PP 145-146.

[6] *Id.* P 169.

companies were required to submit a filing to the Commission that identified merger costs to be recovered and demonstrated that the costs were exceeded by savings produced by the transaction.[7] Duke Companies did not submit a filing to recover merger transaction costs during the audit period. However, as discussed in detail below, the companies recovered merger transaction costs through rates charged.

Consistent with the Commission's merger authorization condition that required Duke Companies to submit proposed market power mitigation measures for approval, the companies submitted an initial compliance filing on October 17, 2011, which proposed to mitigate market power through virtual divestiture of generation. The filing proposed a must-offer obligation under which Duke Companies would sell specified quantities of energy at cost-based rates to entities directly or indirectly serving load in the DEC and DEP Balancing Authority Areas (BAAs). The Commission rejected the filing on the grounds that the market power mitigation proposals did not remedy the market power concerns identified in the Merger Order.[8]

A revised compliance filing was submitted by Duke Companies on March 26, 2012 that proposed permanent and interim market power mitigation measures. To permanently mitigate market power, Duke Companies proposed to build seven transmission expansion projects (TEPs), expedite completion of an eighth project that was already planned, and set aside 25 MW of transfer capacity on their transmission systems for use by third parties (Stub Mitigation). During construction of the TEPs, as an interim measure to protect against potential market power concerns, Duke Companies proposed to enter into power sale agreements with three unaffiliated firms – Cargill Power Marketing, EDF Trading, and Morgan Stanley Capital Markets – to which the companies would sell power during all periods requiring mitigation. The companies also proposed to hire an independent monitor, Potomac Economics Ltd. (Potomac Economics), to verify compliance with the provisions of the power sale agreements.

The Commission accepted the revised compliance filing on June 8, 2012, subject to certain revisions and conditions, which included, among other things, requirements to hold customers harmless from the cost of the mitigation actions and to expand Potomac Economics' duties to verify that the TEPs were completed within the prescribed scope and timeline.[9] The merger was consummated on July 2, 2012.

On December 6, 2013, after the merger was consummated, Duke Companies submitted a motion to supplement its March 26, 2012 compliance filing, due to newly identified information that affected calculation of the impact of the market power

[7] *Id.* P 170.

[8] *Duke Energy Corp.*, 137 FERC ¶ 61,210 (2011).

[9] *See* June 8 Compliance Order, 139 FERC ¶ 61,194 at P 113.

mitigation measures. In the filing, Duke Companies offered to increase the Stub Mitigation by 104 MW (thereby raising the total amount of the transmission set-aside to 129 MW), repair out of service phase-shifting transformers at DEC's Rockingham substation and return them to service, and operate the transformers so as to create additional import capability on the transmission system. The Commission granted the motion and accepted the supplementary compliance filing subject to conditions on October 29, 2014.[10] Moreover, the Commission reiterated its requirement that transmission and wholesale requirements customers be held harmless from costs associated with repairing the transformers and returning them to service.

B. Duke Energy's Public Utility Subsidiaries

During the audit period, the Duke Companies provided electricity service in portions of North Carolina, South Carolina, Florida, Indiana, Ohio, and Kentucky. DEO and DEK also provided natural gas service in portions of Ohio and Kentucky. The following describes the services provided by each company, its open access transmission tariff (OATT), membership in an independent system operator (ISO) or regional transmission organization (RTO), transmission formula rate, and market-based rate authority.

Duke Energy Carolinas, LLC

DEC is a vertically integrated public utility that generates, transmits, distributes, and sells electricity to 2.5 million customers in a 24,000 square mile service area in North and South Carolina. DEC owns 8,302 miles of transmission lines and 19,600 MW of generating capacity.

DEC provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1995 through 2011.[11] In 2011, DEC began recovery of its transmission service cost pursuant to a formula rate that became effective June 1, 2011.[12] However, on March 26, 2012, in connection with the merger transaction, DEC, DEP, and DEF filed for approval of a Joint OATT under section 205 of the FPA and Part 35 of the Commission's regulations. The filing was conditionally accepted by the Commission on June 8, 2012.[13]

[10] October 29 Compliance Order, 149 FERC ¶ 61,078 (2014).

[11] *Duke Power Co.,* 73 FERC ¶ 61,309 (1995) (Duke Power Order).

[12] *Duke Energy Carolinas, LLC*, 137 FERC ¶ 61,058 (2011).

[13] *Duke Energy Corp.,* 139 FERC ¶ 61,193 (2012).

The Joint OATT provided for transmission service at non pancaked rates for transactions involving the combined transmission systems of the companies. DEC's transmission formula rate is incorporated as Schedule 10-B of the Joint OATT. DEC's formula rate implementation protocols are incorporated as Exhibit A of the Joint OATT, and the formula rate template and formula rate principles are contained in Exhibit B. DEC does not belong to an ISO or RTO.

DEC has wholesale power sale agreements with cost-based rates determined under a formula, and it has Commission authorization to make wholesale sales at market-based rates outside its and DEP's BAAs and Peninsular Florida.

Duke Energy Progress, LLC

DEP is a vertically integrated public utility that generates, transmits, distributes, and sells electricity to 1.5 million customers in a 32,000 square mile service area in North and South Carolina. DEP owns 6,981 miles of transmission lines and 12,200 MW of generating capacity.

DEP provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1996 through 2008. In 2008, DEP began recovery of its transmission service cost pursuant to a formula rate that became effective July 1, 2008.[14] Since the merger, DEP has provided transmission service under the Joint OATT with DEC and DEF. DEP's transmission formula rate is incorporated in Attachment H of the Joint OATT. The formula rate template is incorporated as Attachment H-1 of the Joint OATT, and the implementation protocols as Attachment H-2. DEP does not belong to an ISO or RTO.

DEP has wholesale power sale agreements with cost-based rates determined under a formula, and it has Commission authorization to sell energy and capacity at market-based rates outside its and DEC's BAAs and Peninsular Florida.

Duke Energy Florida, LLC

DEF is a vertically integrated public utility that generates, transmits, and delivers electricity to 1.7 million customers in a 13,000 square mile area in central and southern Florida. DEF owns 4,424 miles of transmission lines and 1,200 MW of generating capacity.

[14] *Carolina Power and Light Co.*, Docket No. ER08-889-000 (June 27, 2008) (delegated letter order).

DEF provided open access transmission service under a Commission-approved OATT at cost-based stated rates from 1996 through 2008. In 2008, DEF began recovery of its transmission service cost pursuant to a formula rate that became effective January 1, 2008.[15] Since the merger, DEF has provided transmission service under the Joint OATT with DEC and DEP. DEF's transmission formula rate is incorporated as Schedule 10-A of the Joint OATT. The implementation protocols are designated as Schedule 10-A.1 of the Joint OATT, and the formula rate template as Schedule 10-A.2. DEF does not belong to an ISO or RTO. Additionally, DEF has Commission authorization to sell energy and capacity outside the DEC and DEP BAAs and Peninsular Florida.

Duke Energy Indiana, LLC

DEI is a vertically integrated utility that generates, transmits, distributes, and sells electricity to 810,000 customers within a 23,000 square mile service territory in central, north central, and southern Indiana. DEI owns 7,500 MW of generating capacity and 4,815 miles of transmission lines.

DEI became a member of the Midcontinent Independent System Operator, Inc., (MISO) in 1997 and recovered its cost of transmission service pursuant to cost-based stated rates. In 1998, DEI began to recover its transmission service cost pursuant to a transmission formula rate. DEI's transmission formula rate template is included at Attachment O of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. Additionally, DEI has Commission authorization to sell power at market-based rates outside the DEC and DEP BAAs and Peninsular Florida.

Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

DEO is the direct parent of DEK. The companies are combination electric and gas utilities that transmit, distribute, and sell electricity at retail and wholesale, and distribute and sell natural gas at retail in southwestern Ohio and northern Kentucky, respectively. DEO owns 1,879 miles of transmission lines. The company divested its generating assets pursuant to Ohio's electric restructuring program and received Commission authorization for the divestiture.[16] DEK owns 102 miles of transmission lines and about 1,200 MW of generating capacity.

[15] *Florida Power Corp.,* Docket No. ER08-105-000 (Dec. 17, 2007) (delegated letter order).

[16] *See Dynegy Resource I, LLC,* 150 FERC ¶ 61,232 (2015).

DEO and DEK were members of MISO until January 1, 2012, when they withdrew their membership and joined PJM Interconnection, L.L.C. (PJM).[17] The companies recover transmission service costs pursuant to a transmission formula rate under the PJM OATT. DEO and DEK's transmission formula rate is incorporated as Attachment H-22 of the PJM OATT. The formula rate template is incorporated as Attachment H-22A of the OATT, and the implementation protocols as Attachment H-22B. Additionally, DEO and DEK have Commission authorization to sell power at market-based rates outside the DEC and DEP BAAs and Peninsular Florida.

[17] The Commission conditionally authorized the move in an order issued October 21, 2010. *See Duke Energy Ohio, Inc.*, 133 FERC ¶ 61,058 (2010).

III. Introduction

A. Objectives

The audit evaluated Duke Companies' compliance with conditions established in the Merger Order and associated orders on compliance, requirements of each company's transmission formula rate tariff, and accounting and financial reporting regulations. The audit covered the period January 1, 2011 through January 31, 2016.

B. Scope and Methodology

Audit staff performed specific actions to facilitate the audit and evaluate compliance with the audit objectives. Audit staff also reviewed the effectiveness of Duke Companies' compliance program in relation to the audit objectives and other key factors. To address overall audit objectives, audit staff:

- Conducted an extensive review of publicly available materials to understand the companies' corporate structure and organization, operations, financial accounting and reporting activities, and other key regulatory and business activities, both before and after the merger. Examples of materials and documentation reviewed include Commission rules, regulations, and orders, Form No. 1 reports, FERC Form No. 65, Notification of Holding Company Status, formula rate filings, the Commission's enforcement hotline calls and company self-reports, company-related web sites, and relevant media sources. This also included a review of filings with other government agencies, such as the Securities and Exchange Commission Forms 10-K and 10-Q, Annual and Quarterly Reports;

- Evaluated the companies' internal policies and procedures relevant to the audit objectives;

- Conferred with other Commission staff on various compliance issues to ensure audit findings were consistent with Commission precedent and policy. For example, audit staff communicated with staff from other divisions within the Office of Enforcement and staff from the Office of Energy Market Regulation and Office of General Counsel;

- Conducted two site visits to Duke Energy's headquarters in Charlotte, NC. The visits enabled audit staff to further understand the company's corporate structure, functions, operations, accounting systems and practices, transmission planning and cost-estimating procedures, formula rate, internal audit function, and regulatory and corporate compliance programs. While on site, audit staff interviewed employees and managers responsible for performing tasks within the audit scope, sampled and tested documents to verify compliance with Commission orders related to merger conditions, accounting regulations, financial reporting, transmission formula rates, and related matters. Additionally, audit staff also interviewed compliance program staff, senior officials, internal auditors, and employees who fulfill day-to-day compliance activities for the purposes of carrying out regulatory oversight responsibilities;

- Conducted teleconferences to discuss audit objectives and scope, data requests and responses, technical and administrative matters, compliance concerns, and held a closing conference to discuss the completion of audit fieldwork and results; and

- Issued data requests to gather information not available through public means. This information related to internal policies and procedures, business practices, reporting activities, corporate compliance, internal and external audit reports, merger order conditions and compliance, transaction and operational data, and other pertinent information. Audit staff used this information as underlying support for testing and evaluating compliance with Commission requirements relevant to the audit scope and objectives.

Further, audit staff performed these specific actions to facilitate the testing and evaluation of compliance with relevant requirements for the audit scope areas. A summary of these actions follows.

Compliance with Merger Conditions

To evaluate compliance with the hold harmless and market power mitigation conditions established in the Merger Order and associated compliance orders, audit staff performed audit fieldwork applicable to the merger. Audit staff performed the following steps:

- Reviewed the merger application, supporting testimony and exhibits to understand the context, terms, and conditions of the merger proposal and commitment to hold transmission and wholesale requirements customers harmless from costs of the transaction. Reviewed intervenor comments and protests, and responses to the comments and protests, and also reviewed Duke Companies' compliance filings, intervenor responses, and answers to the responses;

- Evaluated Duke Companies' responses to Commission staff's delegated data requests that sought information regarding the merger application and compliance filings;

- Examined the companies' policies and procedures associated with tracking and accounting for merger transaction costs incurred prior to and following consummation of the merger;

- Performed a comparative analysis of Duke Energy and Progress Energy's accounting for costs of the merger prior to and after its consummation and the companies' policies associated with the accounting;

- Reviewed actions taken by the companies to maintain compliance with merger conditions;

- Analyzed the companies' procedures to ensure compliance with hold harmless conditions and to account for merger transaction costs;

- Conducted sample-based tests of internal costs and external contracted costs incurred by the companies to assess the accounting for the costs and the impact on wholesale rate determinations;

- Obtained information on staff involved in merger activities, including employee names, positions, salaries, work performed on merger activities, and time spent on merger-related activities;

- Reviewed documentation and supporting evidence of merger transaction costs and performed substantive tests of sample data;

- Inspected reports submitted by Potomac Economics regarding the Rockingham phase shifters and other relevant Commission filings;

- Evaluated expenses incurred to repair the Rockingham phase shifters to assess the accounting for the costs and impacts on wholesale rate determinations; and

- Examined costs incurred to operate the TEPs – including the Rockingham phase shifters – from 2012 through Q1 2015 to evaluate the accounting used to record cost of activity and the resulting impact on wholesale rate determinations.

Furthermore, audit staff conducted the following additional steps to evaluate Duke Companies' compliance with the market power mitigation conditions:

- Reviewed the companies' contract with Potomac Economics to ascertain whether the independent monitor had sufficient oversight authority and timely access to data needed to monitor compliance with interim and permanent market power mitigation measures;

- Examined the quarterly independent monitoring reports prepared by Potomac Economics detailing Duke Companies' compliance with interim and permanent market power mitigation conditions;

- Interviewed personnel responsible for reporting the status of TEP construction to Potomac Economics, and reviewed a sample of email communications between the parties;

- Interviewed personnel involved with TEP planning, engineering and design, purchasing and contracting, construction, and project management to verify that the projects were completed as required and to ascertain the amount of labor time employees spent on the projects;

- Identified scope changes made to the TEP plans and assessed the impact of changes on project cost and expected performance of the transmission system;

- Examined a sample of information that Potomac Economics relied on to conclude that the TEPs were placed into service. This information included data from the supervisory control and data acquisition (SCADA) system on the operation of the constructed projects and associated work orders;

- Analyzed photographs of TEP equipment nameplates for asset identification and facility ratings for a sample of major equipment installed, and compared nameplate information to construction work orders and internal company correspondence related to the TEPs;

- Reviewed Duke Companies' written procedures that governed implementation of the power sales agreements required by the Commission's interim market power mitigation measures. Also, interviewed personnel responsible for developing and implementing the agreements, and reviewed Potomac Economics' seasonal and event-based reports to the Commission on the company's performance under the agreements;

- Analyzed a sample of transaction data on power sales DEC and DEP made under the power sale agreements and reviewed transmission schedules on the Open Access Same-time Information System (OASIS) to verify the energy was scheduled and delivered;

- Interviewed power marketing personnel to gain information on operating procedures and processes used to comply with the requirement to set aside firm transmission capacity on the DEC-DEP interface (i.e., Stub Mitigation requirement);

- Reviewed Potomac Economics' reports on the Stub Mitigation requirement and analyzed a sample of data from OASIS regarding transmission offerings and requests for firm transmission service on the DEC-DEP interface;

- Evaluated the DEC-DEP Joint Dispatch Agreement (JDA) and associated operating procedures to understand the methods used to forecast load and determine the mix of generating resources needed to meet load demand on daily and weekly bases;

- Interviewed power marketing employees responsible for scheduling power between the DEC and DEP BAAs, and examined a sample of transactions that involved dispatch of generating resources, reserving and scheduling transmission service consistent with the JDA, and operating the respective BAAs separately. Also, tested a sample of OASIS transmission reservations and schedules to evaluate DEC and DEP's reservations of point-to-point and network transmission service to transmit energy and capacity between the two BAAs; and

- Identified instances in which DEC and DEP used network transmission to deliver power to their respective BAAs, and evaluated these transactions to assess compliance with conditions that restricted certain transactions in the BAAs.

Transmission Formula Rates

To evaluate compliance with the requirements of each company's transmission formula rate tariff, audit staff:

- Reviewed the initial applications filed seeking approval of each company's transmission formula rate tariff, intervenor responses to the filings, any associated settlement agreements with wholesale customers and interested parties, and the Commission orders that approved the transmission formula rate tariffs;

- Examined the transmission formula rate templates and all appendices and attachments used to compute key inputs to the annual transmission revenue requirement and associated formula rate protocols;

- Interviewed employees responsible for populating each public utility's transmission formula rate template, verifying data and calculations, and reviewing and obtaining management approval of the calculated transmission service rates;

- Assessed the adequacy of management oversight and verification controls that support performance of key activities;

- Evaluated data responses and conducted conference calls to understand the accounting for major items affecting the formula rate, including miscellaneous deferred debits, income taxes, and others. Also, reviewed these items to determine compliance with relevant accounting regulations, instructions, and definitions;

- Reviewed annual informational and true-up filings submitted after the initial rate years and during the audit period. Reconciled the Form No. 1 data with formula rate calculations and evaluated discrepancies. Conducted a detailed analysis of supporting worksheets and attachments to evaluate the calculation of transmission formula rate inputs;

- Analyzed footnotes included in each company's Form No. 1 to determine whether information disclosed provided for a reconciliation of publicly available data to balances used to calculate the transmission service rates;

- Performed procedures to verify that transmission formula rate inputs were supported by data reported in each company's Form No. 1;

- Evaluated the companies' accounting for merger transaction costs by assessing documented policies, operating processes, and procedures, and tested a sample of invoices and work orders that included merger activities and associated costs. Analyzed the accounting for the costs and the impact on transmission rate determinations;

- Checked plant balances used to calculate transmission revenue requirements, sampled work order charges included in construction work in progress and plant balances, and performed tests on amortized pre-commercial costs;

- Tested a sample of depreciation accruals on utility plant to assess the depreciation rates applied to the plant; and

- Performed substantive tests on a sample of invoices and work orders that included nonutility expenses, and evaluated the impact of identified misclassified items on transmission rate determinations.

Accounting and Reporting

To evaluate compliance with the Commission's accounting and reporting regulations in the USofA under 18 C.F.R. Parts 101 and 141, audit staff performed the following with respect to the merger:

- Conducted interviews and teleconferences and met with company staff to discuss accounting policies, procedures, and practices. These interviews included discussions with employees involved in the operation of each public utility subsidiary's financial accounting systems to assess the adequacy of accounting and reporting oversight controls related to the merger, and employees in leadership positions responsible for day-to-day oversight of merger activities to understand how merger-related labor was reported on timesheets;

- Examined procedures for preparing, reviewing, and obtaining management approval of the Form No. 1 reports. Reviewed disclosures in the reports to understand major accounting policies;

- Reviewed and evaluated the processes, procedures, and controls the companies used before and after merger consummation to track and account for merger transaction costs;

- Evaluated the Form No. 1 and Securities and Exchange Commission 10-K notes and disclosures related to tracking, accounting, and reporting merger transaction costs;

- Analyzed the companies' accounting entries that recorded merger-related labor, goodwill, TEP project costs and impairments, and the income tax effects of the transaction;

- Reviewed third-party lobbying expenditure disclosures, press articles, meeting schedules, and agendas of internal lobbyists. Interviewed internal lobbyists and support staff to understand the nature and extent of the companies' lobbying activities;

- Tested a sample of work orders, invoices, and associated accounting detail records that support internal lobbyists' labor costs incurred;

- Assessed the impact on wholesale rates of merger and other costs incurred by the companies that were reported in the Form No. 1;

- Tested a sample of FERC accounts for compliance with the Merger Order as well as the companies' internal policies and procedures; and

- Evaluated certain income statement and balance sheet accounts and balances reported in the companies' Form No. 1 reports for 2012 through 2014.

IV. Findings and Recommendations

1. Accounting for Merger Transaction Costs

Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

Pertinent Guidance

The Commission's September 30, 2011 order conditionally authorizing the Proposed Transaction established the following requirement concerning the submission of accounting entries related to the merger:

> To the extent any applicant that is subject to the Commission's Uniform System of Accounts records any aspect of the Proposed Transaction in its accounts, it is directed to file its accounting entries with the Commission within six months of the consummation of the Proposed Transaction. Further, if the accounting entities are recorded six months after the consummation of the Proposed Transaction, the applicant must file those accounting entries with the Commission within 60 days from the date they were recorded. The accounting submission must provide all accounting entries related to the Proposed Transaction, including narrative explanations describing the basis, and the rate impact, of such entries.[18]

The Commission's long-standing precedent stipulates that transaction costs incurred by public utilities associated with a merger are nonoperating in nature and should be charged to Account 426.5, Other Deductions, to the extent the costs are not retained by the parent holding company. For example, in *Allegheny Energy, Inc.,* the Commission stated in part:

> The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in

[18] Merger Order, 136 FERC ¶ 61,245 at P 190.

Account 426.5, Other Deductions.[19]

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

18 C.F.R. Part 101, General Instruction No. 5, Submittal of Questions, states:

> To maintain uniformity of accounting, utilities shall submit questions of doubtful interpretation to the Commission for consideration and decision.

Background

In the Merger Order, the Commission authorized Duke Companies to merge, subject to conditions. With respect to accounting, the Merger Order stated that if any Duke Energy subsidiary subject to the USofA recorded any aspect of the merger on its books, the subsidiary must file the accounting entries with the Commission within 60 days of consummation of the transaction. The Commission noted that such accounting entries include entries related to transaction costs, merger premiums, acquisition adjustments, goodwill, or any cost related to the merger.[20]

Moreover, pursuant to long-standing Commission precedent, merger transaction costs are considered nonoperating in nature and are required to be recorded to Account 426.5, Other Deductions. The text of Account 426.5 states that the account shall include expenses that are nonoperating in nature. Audit staff evaluated Duke Companies' accounting for the merger and found that the companies recorded merger transaction costs on their books. Further, contrary to the requirements of the Merger Order and Commission accounting rules, Duke Companies neither filed accounting entries with the Commission that reflected the recording of the transaction costs on the companies' books nor accounted for nonoperating merger transaction costs in Account 426.5.

[19] *See Allegheny Energy, Inc.*, 133 FERC ¶ 61,222, at P 73 (2010). *See also Midwest Power Systems, Inc. and Iowa-Illinois Gas and Elec. Co.*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Co. and MidAmerican Energy Holdings Co.*, 85 FERC ¶ 61,354, at 62,370 (1998); and *Wis. Elec. Power Co.,* 74 FERC ¶ 61,069, at 61,192 (1996).

[20] Merger Order, 136 FERC ¶ 61,245 at n. 414.

Duke Companies collectively incurred over $1 billion in merger costs and recorded the costs on their Form No. 1 reports from 2011 through October 30, 2015. The costs were accounted for in numerous operating plant and expense accounts, including: A&G expense; payroll tax; customer account expense; transmission, distribution, and production operating and maintenance expense; and other accounts.

Duke Energy explained that it interpreted the Merger Order to require submittal of accounting entries only if a subsidiary used the purchase method of accounting and increased the book value of assets for goodwill acquired in the transaction. However, the Merger Order did not require the companies to file accounting entries only if they used the purchase method of accounting or increased the book value of assets for goodwill. To the contrary, the Merger Order stated that if *any entity* subject to the USofA recorded *any aspect* of the merger on its books, it must file its accounting entries with the Commission. The Merger Order further clarified that such accounting entries included entries related to transaction costs, merger premiums, acquisition adjustments, goodwill, or any cost related to the merger.

All of Duke Energy's public utility subsidiaries were subject to the Commission's USofA, therefore the companies should have filed accounting entries. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries not in accordance with Commission accounting requirements.

Furthermore, Duke Companies should have recorded merger transaction costs incurred to effectuate the merger in Account 426.5 rather than in operating accounts consistent with the text of Account 426.5 and Commission precedent.[21] Audit staff found that prior to March 2012, both Duke Energy and Progress Energy recorded merger transaction costs in operating accounts. However, in March 2012, Progress Energy transferred its merger transaction costs to Account 426.5, due to its interpretation of a Commission merger order that required such accounting. Duke Energy did not implement a similar reclassification of its merger transaction costs. Duke Energy explained that it believed costs associated with the merger were appropriately recorded in operating accounts.

[21] Post-merger integration cost (i.e., cost incurred following consummation of a merger, in which the assets, personnel, and business activities of the entities participating in the merger are combined) are recordable to operating accounts; however, the cost would be subject to the Commission's hold harmless commitments and prohibited from recovery in jurisdictional rates.

In April 2012, Duke Energy's external auditors questioned its accounting of the merger transaction costs. The external auditors informed Duke Energy of the Commission's merger accounting policy, which the auditors interpreted as requiring merger transaction costs to be recorded below-the-line in Account 426.5. Duke Energy disagreed with the auditors' interpretation. Rather than adjusting its accounting, Duke Energy and its external auditors agreed that Duke Energy's management representation letter would be revised. The letter is a signed attestation by Duke Energy management of the accuracy of its financial statements. The letter was revised to include a statement that Duke Energy was aware of Commission orders that indicated merger transaction costs should be recorded in Account 426.5, but Duke Energy nonetheless believed that its classification of merger transaction costs in operating accounts was appropriate.

The Duke Companies were required to file the accounting entries with the Commission as directed in the Merger Order. The companies' improper accounting for merger transaction costs contributed to the inappropriate recovery of merger-related internal labor and outside service costs through charges to Commission-jurisdictional customers. To the extent Duke Companies was uncertain about the appropriate accounting for the transaction, the companies should have submitted accounting questions of doubtful interpretation to the Commission for consideration and decision. The Commission expects Duke Companies, and all entities that have a reporting requirement for transactions under FPA section 203, to fully comply with the orders approving such transactions. Duke Companies' lack of compliance with the Merger Order reporting requirement is a very serious matter.

Recommendations

We recommend Duke Companies:

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

2. Merger Transaction Internal Labor Costs

Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million.

Pertinent Guidance

The Commission's Merger Order states in part:

> We accept Applicants' commitment to hold transmission and wholesale requirements customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within the next five years, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by quantified savings resulting from the transaction, in addition to any requirements associated with filings made under section 205.[22]

The Commission's June 8, 2012 order accepting Duke Companies' revised compliance filing states in part:

> [T]he Commission will require Applicants to hold transmission and wholesale requirements customers harmless from the costs of the Transmission Expansion Projects in accordance with the hold harmless commitment, as set forth in the Merger Order.[23]

[22] Merger Order, 136 FERC ¶ 61,245 at PP 169-170.

[23] June 8 Compliance Order, 139 FERC ¶ 61,194 at P 91.

The Commission's October 29, 2014 order denying rehearing and granting a motion to supplement compliance filing states in part:

> [T]he Commission requires Applicants to hold transmission and wholesale requirements customers harmless for five years from costs related to the Phase Shifters.[24]

Background

On April 4, 2011, Duke Energy, Progress Energy, and their public utility subsidiaries (collectively, Duke Companies) filed an application seeking Commission authorization of a proposal to merge under section 203 of the FPA and Part 33 of Commission regulations. In the application, Duke Companies committed to exclude costs related to the merger from transmission and wholesale requirements customers' rates, except to the extent the companies demonstrated in a section 205 rate filing that merger-related savings were equal to or in excess of merger costs included in the rate filing. On September 30, 2011, the Commission issued an order authorizing Duke Companies to merge subject to conditions. Among other things, the Commission conditioned authorization on Duke Companies maintaining its commitment to hold transmission and wholesale requirements customers harmless from costs related to the merger. Pursuant to this condition, "[a]ll transaction related costs, not only costs related to consummating the transaction," were required to be excluded from rates charged.[25] To determine if Duke Companies complied with the hold harmless requirement, audit staff examined the companies' procedures for tracking and accounting for merger costs, and excluding the costs from rates.

To track costs incurred due to the merger, the companies established special accounting processes and procedures. Audit staff found that Duke Energy and Progress Energy did not account for merger costs using the same accounting treatment prior to consummation of the merger. Prior to consummation of the merger, Duke Energy accounted for merger transaction costs in above-the-line operating accounts, whereas Progress Energy accounted for the costs below-the-line in Account 426.5, Other Deductions.[26] However, after consummation of the merger, Progress Energy adopted Duke Energy's internal accounting policy for merger transaction costs and thereafter began accounting for incurred merger transaction costs in operating accounts.

[24] October 29 Compliance Order, 149 FERC ¶ 61,078 at P 81.

[25] Merger Order, 136 FERC ¶ 61,245 at P 169.

[26] Account 426.5, Other Deductions, 18 C.F.R. Part 101 (2015), provides for the recording of expenses that are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

Duke Energy devised and distributed instructions to its public utility subsidiaries regarding accounting for merger costs, which it characterized as Costs to Achieve (CTA) the merger. Duke Energy defined CTA as "costs that are incremental and nonrecurring that would otherwise not have been incurred but for the merger or integration planning efforts."[27] The CTA instructions identified the accounting codes to be used to account for and track merger costs. The codes included the business and operating unit that incurred the cost, process, task, project ID, and other details associated with activities that involved the incurrence of merger costs. The CTA instructions were communicated to managers and staff assigned to work on the merger, and employees were trained on use of the accounting codes. Duke Energy's shared services accounting group retrieved merger cost data from the general ledgers of the public utility subsidiaries, reviewed charges for reasonableness, and compared actual and budgeted costs as part of its monthly reporting process.

Duke Energy's shared services accounting group developed additional procedures to exclude certain merger costs from wholesale power and transmission formula rate determinations of the public utility subsidiaries. The procedures included preparation of monthly spreadsheets identifying merger costs included in each subsidiary's operating accounts as reported in the Form No. 1. The rate staff of each public utility subsidiary was instructed to subtract the merger costs from operating accounts in the Form No. 1 that were used to compute the company's transmission formula rate. The procedures were designed to prevent merger costs reported in operating accounts from being incorporated in wholesale power and transmission formula rate determinations.

As a result of these procedures under which merger-related internal labor costs were not treated as CTA, audit staff found that Duke Companies' wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.5 million due to the inclusion of merger transaction internal labor costs in wholesale power and transmission rate determinations without first making a section 205 filing with the Commission as the Merger Order required. The improper charges included an estimated $17.2 million through inclusion of internal labor costs incurred in merger transaction and integration activities, and over $300,000 through inclusion of

[27] This included costs incurred in developing, executing, and obtaining approvals for the merger as well as incremental integration costs, but did not include merger-related internal labor costs Duke Companies considered non-incremental. For example, the costs included severance payments, employee relocation and retention costs, bonuses paid to employees for their work on the merger, investment banking and advisory fees, state and Federal regulatory expenses, costs for integrating accounting and information technology systems, transmission systems, fuel and dispatch systems, as well as transition costs, mitigation/concession costs, depreciation expenses for merger projects, and fees paid to providers of transmission service between the regulated utilities.

internal labor costs incurred to construct and operate the transmission expansion projects (TEPs), and repair and operate the Rockingham phase shifters.

Merger Transaction Internal Labor

During fieldwork, audit staff determined that Duke Energy excluded merger transaction internal labor from its definition of CTA and its CTA coding procedures. Duke Energy acknowledged that employees spent substantial time on merger activities. However, the company contended that employees performed merger activities in addition to their regular responsibilities and, therefore, no incremental internal labor costs were incurred due to the merger. Based on a belief that the hold harmless obligation applied only to incremental merger costs, Duke Energy instructed employees not to use the special CTA codes to report time devoted to merger activities on their timesheets. Consequently, public utility subsidiaries did not track all merger transaction internal labor costs or exclude all such costs from wholesale power and transmission formula rate cost computations. As a result, the subsidiaries improperly included some merger transaction internal labor costs in wholesale power and transmission formula rate determinations and inappropriately charged the costs to customers.

Contrary to Duke Energy's interpretation, the Merger Order required Duke Companies to hold customers harmless from "*all* merger transaction costs," and did not limit this requirement only to costs Duke Energy considered incremental. Duke Energy's assertion that its hold harmless obligation extended only to incremental costs must be made within a section 205 proceeding where it and other interested parties will have an opportunity to assess all evidence that supports or contradicts such a position. By excluding internal labor from its CTA tracking and reporting procedures, Duke Energy did not have the ability to determine the proportion of employee labor costs devoted to merger-related tasks, as opposed to utility-related tasks, the cost of which are appropriately recovered in rates. Moreover, even in the absence of detailed time reporting and accounting data, the companies were nonetheless prohibited from including these merger transaction costs in rate determinations without first receiving Commission authorization to do so in a section 205 proceeding in accordance with Merger Order requirements.

Since Duke Companies did not track all merger transaction internal labor costs, audit staff issued data requests and interviewed company employees during site visits and conference calls to develop its own estimate of the amount of merger transaction internal labor costs Duke Companies incurred and included in transmission formula rate charges. The information audit staff obtained confirmed that company employees spent substantial amounts of time working on the merger, as Duke Energy acknowledged. For example, Duke Energy reported in data responses that over 2,400 employees were engaged in merger activities from mid-2010 through present. The total included more than 2,300 employees who participated in over 300 merger integration projects performed to upgrade and integrate the companies' information technology, human resources, finance, and accounting systems and functions. About 140 employees were engaged in merger planning and evaluation, preparing and supporting merger applications and post-merger litigation, and developing and implementing measures to mitigate market power due to the merger. Audit staff found through assessment of data response information and interviews of company staff, that certain of these employees worked full time on the merger for the duration of their projects, while others devoted 50 percent or more of their time to assigned merger activities. Moreover, detailed analysis of integration projects with the largest budgets indicated that the assigned employees were heavily engaged in the projects for prolonged periods of time.

Audit staff used this information, interviews with employees engaged in merger activities, employees' salary information procured from data responses, and salary estimates found on publicly available sources to approximate the amount of internal labor costs incurred due to the merger. Audit staff estimated that the Duke Companies incurred between \$55 million and \$75 million of internal labor costs related to the merger, including salaries and benefits.

Audit staff then asked Duke Energy to provide its own estimate of the internal labor costs associated with each merger activity and a breakdown by FERC account. As the table below shows, Duke Energy estimated that \$78.8 million in merger transaction internal labor costs were incurred to perform four primary merger tasks. Duke Energy's estimate exceeded audit staff's high-range estimate of internal labor costs.

		A	B
Row	**Merger Tasks**	**Duke Companies' Estimated Internal Labor Cost (Million $)**	**Estimated Internal Labor Included in the Revenue Requirements of Wholesale Power and Transmission Rates (Million $)**
1	Merger Planning, Evaluation, Due Diligence	2.3	0.1
2	Preparation and Support for Regulatory Applications and Post-Merger Litigation	3.9	0.2
3	Development and Implementation of Measures to Mitigate Market Power	0.6	0.03
4	Planning, Management, and Execution of Merger Integration Projects	72.0	16.9
	Total	**78.8**	**17.2**

Of the \$78.8 million in merger transaction internal labor costs estimated by Duke Energy, about \$1.6 million of the costs were recorded in distribution operating and maintenance expense accounts that were not included in Commission-jurisdictional rate determinations, and $31.4 million was recorded in production and transmission operating and maintenance expense accounts incorporated in wholesale power and transmission formula rates. Duke Energy estimated that wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $17.2 million.[28] The remaining $45.8 million in merger transaction internal labor costs were charged to capital work orders for integration projects that are under construction and not yet completed. Duke Energy represented that these costs have been classified as CTA, and will be excluded from wholesale power and transmission formula rates when the projects are completed.

By including these merger-related tasks in its definition of CTA, Duke Energy acknowledged that the merger activities employees performed would not have been required in the absence of the merger. Since the work was not related to utility service, employee time engaged on the merger should have been excluded from transmission formula rate determinations. In accordance with the hold harmless commitment, to recover merger costs in their wholesale power or transmission rates, the companies were required to submit a section 205 filing with the Commission detailing costs to be recovered and demonstrating that the costs were offset by quantified savings produced by the merger. Duke Companies did not submit a section 205 filing; therefore, the companies should not have recovered the costs in rates charged.

TEP Operating Expenses

Duke Energy's public utility subsidiaries included an estimated $300,000 of merger transaction internal labor costs in the transmission customers' formula rate revenue requirement for costs related to the TEP projects from 2012 through 2015. This amount was incurred to repair and operate the Rockingham phase shifters. The $300,000 was recorded as transmission maintenance expenses in Account 570, Maintenance of Station Equipment. In accordance with Duke Companies' internal accounting policy, the companies neither characterize the costs as merger-related CTA nor exclude the costs from transmission formula rate determinations. As a result, the $300,000 was included in transmission formula rates, and thus a portion of these costs was inappropriately charged to transmission customers.

In its June 8 and October 29 Compliance Orders, the Commission explicitly directed Duke Companies to hold customers harmless from all costs related to the TEPs

[28] During the audit, DEC and DEP had about 20 wholesale power customers under service contracts with cost-based rates determined under a formula to which merger transaction internal labor costs were incorporated. As a result, a portion of the merger transaction labor costs included in the formula was charged to wholesale power customers.

and the Rockingham phase shifters, consistent with the hold harmless commitment established in the Merger Order. Duke Companies should not have included these internal labor charges in transmission formula rate determinations without first submitting a section 205 filing to the Commission that demonstrated that the costs were offset by quantified savings produced by the merger.

Recommendations

We recommend Duke Companies:

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

3. Merger Transaction Outside Services and Related Costs

Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 application demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $745,000.

Pertinent Guidance

The Commission's Merger Order states in part:

> We accept Applicants' commitment to hold transmission and wholesale requirements customers harmless for five years from costs related to the Proposed Transaction. We interpret Applicants' hold harmless commitment to include all transaction-related costs, not only costs related to consummating the transaction.
>
> If Applicants seek to recover transaction-related costs through their wholesale power or transmission rates within the next five years, they must submit a compliance filing that details how they are satisfying the hold harmless requirement. If Applicants seek to recover transaction-related costs in an existing formula rate that allows for such recovery within the next five years, then that compliance filing must be filed in the section 205 docket in which the formula rate was approved by the Commission, as well as in the instant section 203 docket. In such filings, Applicants must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by quantified savings resulting from the transaction, in addition to any requirements associated with filings made under section 205.[29]

The Commission's long-standing precedent stipulates that transaction costs incurred by public utilities associated with a merger are nonoperating in nature and should be charged to Account 426.5, Other Deductions, to the extent the costs are not passed on to the parent holding company. For example, in *Allegheny Energy, Inc.*, the Commission stated in part:

[29] Merger Order, 136 FERC ¶ 61,245 at PP 169-170.

The Commission has previously determined that merger transaction costs are considered non-operating in nature and should be recorded in Account 426.5, Other Deductions.[30]

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

Background

In the process of evaluating Duke Companies' compliance with the hold harmless commitment, audit staff issued data requests and interviewed company employees regarding the accounting and formula rate impact of activities engaged prior to and after public announcement of the merger, such as outside service costs incurred to facilitate the merger and associated internal corporate costs. In reviewing materials received, audit staff found that Duke Energy's corporate development group incurred over $1.5 million in merger transaction costs in the second half of 2010 (i.e., prior to the merger announcement in January 2011) and allocated those costs to its then public utility subsidiaries – DEC, DEI, DEO, and DEK – prior to consummation of the merger.

The costs included $1.35 million paid to outside consultants, lawyers, and accountants for financial forecasting, analysis of market power issues and related services, and $150,000 of internal labor and other costs related to this work. The subsidiary companies improperly recorded the merger transaction outside service costs in Account 923, Outside Services Employed, and most of the associated internal labor and other costs in Account 920, Administrative and General Salaries. Account balances reported in each company's Form No. 1 were included in the determination of the company's wholesale power and transmission formula rate service charges.

DEC, DEI, DEO, and DEK reported these costs in their respective 2010 Form No. 1 reports. The companies neither characterized the costs as merger-related CTA following the merger announcement and issuance of the Merger Order, nor excluded the costs from wholesale power and transmission formula rate determinations in 2011 or subsequent years.

[30] *See Allegheny Energy, Inc.*, 133 FERC ¶ 61,222 at P 73 (2010). See also *Midwest Power Systems, Inc. and Iowa-Illinois Gas and Elec. Co.*, 71 FERC ¶ 61,386, at 62,509 (1995); *MidAmerican Energy Co. and MidAmerican Energy Holdings Co.*, 85 FERC ¶ 61,354, at 62,370 (1998); and *Wis. Elec. Power Co.*, 74 FERC ¶ 61,069, at 61,192 (1996).

Pursuant to the hold harmless commitment, the companies should not have included the $1.5 million in merger transaction costs in wholesale rate determinations without first submitting a section 205 filing to the Commission that demonstrated the costs were offset by quantified savings produced by the merger. Moreover, pursuant to long-standing Commission precedent, the merger transaction costs the companies recorded in Accounts 920 and 923 are considered nonoperating in nature and, as such, were required to be recorded to Account 426.5. The text of Account 426.5 states that the account shall include expenses that are nonoperating in nature. Duke Energy estimated that wholesale power and transmission customers' revenue requirements were inappropriately overstated $745,000.

Recommendations

We recommend Duke Companies:

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

4. Use of the Consolidated Method of Accounting

DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their Form No. 1 reports, contrary to the Commission's long-standing accounting policy.

Pertinent Guidance

Order No. 469 revised and amended sections of 18 C.F.R. Parts 101 and 201 to adopt the equity method of accounting for long-term investments in subsidiaries and add new balance sheet and income statement accounts, and definitions. Order No. 469 states in part:

> Under the equity method of accounting, the utility's investment account is increased or decreased to reflect the utility's proportionate share of a subsidiary's current earnings applicable to common stock regardless of whether the earnings are actually paid out as dividends to the utility. When dividends are received, the investment account is reduced by an equivalent amount.[31]

18 C.F.R. Part 101, Account No. 123.1, Investment in Subsidiary Companies, states:

> A. This account shall include the cost of investments in securities issued or assumed by subsidiary companies and investment advances to such companies, including interest accrued thereon when such interest is not subject to current settlement plus the equity in undistributed earnings or losses of such subsidiary companies since acquisition. This account shall be credited with any dividends declared by such subsidiaries.
>
> B. This account shall be maintained in such a manner as to show separately for each subsidiary: the cost of such investments in the securities of the subsidiary at the time of acquisition; the amount of equity in the subsidiary's undistributed net earnings or net losses since acquisition; advances or loans to such subsidiary; and full particulars regarding any such investments that are pledged.

[31] *Revisions in the Uniform System of Accounts, and Annual Report Forms No.1 and No. 2 to Adopt the Equity Method of Accounting for Long-Term Investments in Subsidiaries*, Order No. 469, 49 FPC 326, *reh'g denied*, 49 FPC 1028 (1973).

18 C.F.R. Part 101, Account 216.1, Unappropriated Undistributed Subsidiary Earnings, states:

> This account shall include the balances, either debit or credit, of undistributed retained earnings of subsidiary companies since their acquisition. When dividends are received from subsidiary companies relating to amounts included in this account, this account shall be debited and account 216, Unappropriated Retained Earnings, credited.

18 C.F.R. Part 101, Account No. 418.1, Equity in Earnings of Subsidiary Companies, states:

> This account shall include the utility's equity in the earnings or losses of subsidiary companies for the year.

Background

DEC and DEP formed wholly owned special purpose subsidiaries, Duke Energy Receivables Finance Company, LLC (DERF) and Duke Energy Progress Receivables, LLC (DEPR), respectively, in 2003 and 2013. The companies accounted for their investments in the subsidiaries using the consolidated method of accounting. Specifically, DEC consolidated DERF in its Form No. 1 reports from 2003 through 2013; and DEP consolidated DEPR in its Form No. 1 in 2013. The accounting resulted in the recognition of property, expenses, revenue, debt, and equity of the subsidiaries in DEC and DEP's respective Form No. 1 reports. During the course of the audit, in 2014, the companies ceased accounting for their investments in the subsidiaries using the consolidation method of accounting and began using the equity method of accounting.

Prior to 2014, DEC and DEP's accounting for their investments in the subsidiaries was not consistent with the Commission's accounting requirements, which required the companies to account for the investments using the equity method of accounting. In accordance with the provisions of Order No. 469, the companies were required to account for the subsidiaries as investments in Account 123.1, Investments in Associated Companies, and record equity in earnings of the subsidiaries in Account 418.1, Equity in Earnings of Subsidiary Companies, and undistributed retained earnings of the subsidiaries in Account 216.1, Unappropriated Undistributed Subsidiary Earnings.[32]

[32] *Id.*

On August 19, 2015, during the course of the audit, Duke Energy submitted a request to the Commission on behalf of the companies for retroactive and prospective waivers of the equity method accounting requirement.[33] In the filing, among other things, DEC and DEP acknowledged that they had inappropriately accounted for investments in their subsidiaries using the consolidation method of accounting, and improperly included the results of the subsidiaries' operations in cost of service formula rate determinations. On December 18, 2015, the companies submitted a filing to the Commission under section 205 of the FPA seeking approval of proposed amendments to the formula rates in their Joint OATT and wholesale power agreements to provide for consolidation of the subsidiaries for cost of service rate determination purposes.[34]

Duke Energy did not notify audit staff of the inappropriate consolidation accounting, or of its request for waiver of the equity accounting requirements. The company should have disclosed the erroneous accounting to audit staff when it discovered the matter, which according to its representation occurred in late 2014. However, neither audit staff nor the Commission was notified of the improper accounting and the associated rate impacts until August 2015. Duke Energy's lack of timely disclosure of DEC and DEP's noncompliance with Commission regulations is problematic. The company should take necessary steps to ensure that its corporate compliance culture and program are strengthened to prevent situations like this on a going forward basis.

[33] Duke Energy Carolinas, LLC, et al., Request for Waiver, Docket No. AC15-174-000, (filed Aug. 19, 2015). The filing requested waivers of the equity accounting requirement on behalf of DEC, DEP, and DEF, which formed a wholly owned subsidiary Duke Energy Florida Receivables, LLC (DEFR) in 2014. The Chief Accountant issued a delegated letter order on February 12, 2016 that granted the requested waivers to the companies and directed specific accounting regarding sales of accounts receivable. Duke Companies filed a request for rehearing of the letter order on March 14, 2016.

[34] *Duke Energy Carolinas, LLC, et al.*, Docket Nos. ER16-577-000, ER16-578-000, and ER16-579-000. The Commission issued delegated letter orders on February 11, 2016, accepting for filing the amendments to the Joint OATT and rate schedules to provide for DEC, DEP, and DEF's use of the consolidated method of accounting for ratemaking purposes.

Recommendations

We recommend Duke Companies:

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

5. Accounting for Sales of Accounts Receivable

DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

Pertinent Guidance

18 C.F.R. Part 101, Account 930.2, Miscellaneous General Expenses, states in part:

> This account shall include the cost of labor and expenses incurred in connection with the general management of the utility not provided for elsewhere.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states in part:

> This account shall include other miscellaneous expenses which are nonoperating in nature, but which are properly deductible before determining total income before interest charges.

The Commission addressed the appropriate accounting for the sale of accounts receivable in Opinion No. 375, which stated in part:

> From an accounting standpoint, we find that the record supports the staff and intervenors' position – which the initial decision adopted – that the loss on the sale of accounts receivable was erroneously recorded by SERI [System Energy Resources, Inc.] in Account 930.2. . ..[35]

Background

During audit fieldwork, audit staff analyzed data regarding transactions between DEC, DEP, and DEF and the companies' respective nonutility subsidiaries, DERF, DEPR, and DEFR, and interviewed employees responsible for accounting for the transactions. The transactions involved the companies' sales of accounts receivable to their subsidiaries. The receivables arose from billings on sales of electricity and related services by the companies. The companies sold the receivables to their subsidiaries at a loss (or discount), and accounted for the loss as an expense by debiting Account 930.2, Miscellaneous General Expenses, an account included in wholesale power and transmission service cost formula rate determinations, for the amount of the loss. DEC,

[35] *System Energy Resources, Inc.*, 60 FERC ¶ 61,131 (1992).

DEP, and DEF recognized total losses of $149.6 million, $35.1 million, and $23.5 million, respectively, from 2011 through 2014.

Audit staff also discovered that there were similar transactions involving sales of accounts receivable by DEI, DEO, and DEK to Cinergy Receivables, a Duke Energy subsidiary. However, through discussions with audit staff, Duke Energy represented that instead of recording losses on sold receivables in Account 930.2, DEI, DEO, and DEK accounted for the losses in Account 904, Uncollectible Accounts, an account not included in wholesale power or transmission service cost formula rate determinations.

DEC, DEP, and DEF performed collection services on behalf of their subsidiaries associated with the sold receivables whereby the companies collected bill payments from customers and remitted funds received to the subsidiaries. The companies charged the subsidiaries a fee for performing the collection service, which effectively resulted in a reimbursement of the collection service cost incurred by the companies. Expenses incurred by the companies associated with performing the collection service were accounted for by debiting the costs to Account 903, Customer Records and Collection Expenses. These expenses were also accounted for as a debit in Account 930.2 that Duke Energy represented was the fee billed to the subsidiaries for performing the collection service. As a result of this accounting, DEC, DEP, and DEF double-counted expenses in their respective Form No. 1 reports associated with collection services performed. Furthermore, the companies accounted for the reimbursements of their incurred collection service expenses that resulted from their billed subsidiaries by crediting Account 421, Miscellaneous Non-Operating Income.

Duke Companies' accounting for the loss on the sale of the receivables was not consistent with the Commission's accounting requirements and precedent. Under the Uniform System of Accounts (USofA), sales of accounts receivable constitute the disposition of utility assets. The USofA contemplates that in transactions of this nature, a company should recognize a gain or loss, measured by the difference between the net book value of the asset at the date of the sale and the proceeds from the sale, less related fees and expenses of the sale. Further, the USofA requires a company to record any gains or losses from the disposition of assets in nonoperating expense accounts, except with respect to the sale of future use property.[36] The instructions to Account 426.5, Other Deductions, provide for the recording of nonoperating expenses of this nature. Additionally, the Commission has previously addressed the matter of the appropriate

[36] With respect to future use property recorded in Account 105, Electric Plant Held for Future Use, the USofA requires a company to include a gain on a sale in Account 411.6, Gains from Disposition of Utility Plant, and a loss in Account 411.7, Losses from Disposition of Utility Plant.

accounting for sales of receivables in its Opinion No. 375, wherein it was determined that the loss on the sale of receivables should be accounted for in Account 426.5.[37]

In addition, DEC, DEP, and DEF's accounting for reimbursements of incurred collection service expenses was not consistent with the Commission's accounting requirements. The USofA contemplates that such reimbursements of collection service expenses incurred by DEC, DEP, and DEF on behalf of their respective subsidiaries be recorded as a reduction of the expenses. Accordingly, the companies should have accounted for the reimbursements through a credit entry to the collection service expenses recorded in Account 903.

Duke Energy represented that prior to 2014, DEC and DEP's accounting for the losses on the sales of receivables and collection service fees billed to the subsidiaries that were recorded in Account 930.2 had no impact on service rates charged to wholesale power and transmission formula rate customers due to accounting entries the companies made associated with consolidation method accounting that offset the items and neutralized the rate impact. Duke Energy indicated that the companies made the offsetting entries from the respective dates their subsidiaries were established and transactions initiated through 2013.[38] However, in 2014, DEC and DEP ceased their practice of using the consolidation method of accounting.[39] Cessation of consolidation method accounting led the companies to end their practice of recording the offsetting entries. Moreover, DEF established its subsidiary, DEFR, in 2014, and did not record any accounting entries to offset its losses on the sales and collection service fees billed to its subsidiary. As a result, rates charged by DEC, DEP, and DEF based on amounts reported in the companies' respective 2014 Form No.1 reports included the nonoperating losses and collection service fees that were misclassified in Account 930.2 and not offset by other entries. This led to DEC, DEP, and DEF inappropriately including the losses and fees of $38.1 million, $33.1 million, and $23.5 million, respectively, in rate determinations.

The companies' accounting mistakes led to an estimated $94.7 million of costs being inappropriately included in wholesale power and transmission formula rate service cost determinations during the audit period. Duke Energy estimated that this resulted in wholesale power and transmission customers' revenue requirements being inappropriately overstated by an estimated $61 million.

[37] *System Energy Resources, Inc.*, 60 FERC ¶ 61,131 (1992).

[38] DEC's subsidiary, DERF, was established in 2003, and DEP's subsidiary, DEPR, was established in 2013.

[39] *See* Finding No. 4, Consolidation Method of Accounting.

On March 14, 2016, Duke Companies filed a request for rehearing of the Chief Accountant letter order in Docket No. AC15-174-000 challenging the order's decision regarding the appropriate accounting for losses on the sale of receivables, which is also addressed by this Audit Finding. In light of the current challenge to the Chief Accountant's order and uncertain outcome, as well as, the potential of a contested audit over the identical issue, in this instance the portions of this Audit Finding that relate to the losses issues, including Recommendations 17 and 18, shall be held in abeyance and shall be subject to the outcome of the rehearing request and any subsequent petitions for court review. Although the recommendations regarding the portion of this Audit Finding relating to the losses issues are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for court review, the requirement to make refunds in accordance with Recommendation 21 below is not impacted by the rehearing request.

Recommendations

We recommend Duke Companies:

17. Revise procedures to ensure that all costs and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all losses associated with receivable sales are recorded in Account 426.5.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

6. Accounting for Lobbying Expenses

Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 to 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

Pertinent Guidance

18 C.F.R. Part 101, Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, states in part:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances . . . or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials. . . .

Background

Audit staff evaluated costs incurred by Duke Companies associated with civic, political, and related activities during the audit period. Audit staff reviewed third-party lobbying expenditure disclosures, press articles, internal lobbyist meeting schedules and agendas, and interviewed internal lobbyists and support staff to understand the nature and extent of the companies' lobbying activities. In addition, audit staff tested a sample of work orders, invoices, and associated accounting detail records that support internal lobbyists' labor costs incurred. Audit staff discovered that Duke Companies improperly recorded nearly $2.4 million in lobbying costs to above-the-line operating accounts rather than to Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, as required.

Account 426.4 provides for reporting expenditures for the purpose of influencing public opinion, such as lobbying expenses. Audit staff found that Duke Companies recorded a portion of these costs associated with wages and salaries of internal lobbyist and support staff in Account 426.4 as required, but failed to properly charge other related costs to the account associated with the labor, such as payroll taxes, retirement, health, and other benefits. Audit staff also found that the companies incorrectly accounted for amounts paid to outside firms that lobby on behalf of the companies. Duke Companies improperly included these expenses in wholesale power and transmission formula rate determinations and recovered a portion of the costs through charges to customers.

Further, audit staff found that Duke Companies lacked formal procedures and oversight controls to help ensure that lobbying costs were accounted for appropriately.

The companies should implement procedures to reduce the risk that lobbying costs are inappropriately accounted for and included in jurisdictional rate determinations.

Recommendations

We recommend Duke Companies:

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying costs in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

7. Allocation of Lobbyist Labor Costs

Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

Pertinent Guidance

18 C.F.R. Part 101, General Instruction No. 9, Distribution of Pay and Expenses of Employees, states:

> The charges to electric plant, operating expense and other accounts for services and expenses of employees engaged in activities chargeable to various accounts, such as construction, maintenance, and operations, shall be based upon the actual time engaged in the respective classes of work, or in case that method is impracticable, upon the basis of a study of the time actually engaged during a representative period.

18 C.F.R. Part 101, General Instruction No. 10, Payroll Distribution, states:

> Underlying accounting data shall be maintained so that the distribution of the cost of labor charged direct to the various accounts will be readily available. Such underlying data shall permit a reasonably accurate distribution to be made of the cost of labor charged initially to clearing accounts so that the total labor cost may be classified among construction, cost of removal, electric operating functions (steam generation, nuclear generation, hydraulic generation, transmission, distribution, etc.) and nonutility operations.

18 C.F.R. Part 101, Account 426.4, Expenditures for Certain Civic, Political, and Related Activities, states in part:

> This account shall include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances . . . or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials . . . .

Background

In connection with the evaluation of Duke Companies' expenditures for lobbying activities, audit staff discovered that the companies' allocation of the labor costs of internal lobbyists and their support staff was based in part on the amount of time that state legislatures and Congress were in session. Duke Energy explained that these entities were in session on average 180 days a year, and that lobbying activities of its staff to influence legislation would typically be performed while the legislatures and Congress were in session. This resulted in the companies using a default allocator that charged 50 percent of lobbying costs above-the-line to operating accounts and 50 percent below-the-line to Account 426.4, Expenditures for Certain Civic, Political, and Related Activities.

Audit staff interviewed internal lobbyists and their support staff to understand their roles and job assignments, and reviewed lobbyists' schedules as documented in email, itineraries from industry conferences, and other materials. Duke Energy represented that the companies' internal lobbyist performed internal corporate functions such as (1) budgeting, (2) performance appraisals, (3) training, and (4) other activities. However, audit staff could not determine based on documentation provided, that the 50/50 labor allocation split between above- and below-the-line accounting for lobbying and related costs was accurate or reasonable. Moreover, audit staff discovered that the companies neither had a formal oversight review process to assess the accuracy of the labor allocations nor maintained documentation to support the allocations.

General Instructions No. 9, Distribution of Pay and Expenses of Employees, and No. 10, Payroll Distribution, require public utilities to charge lobbying-related labor to operations based on actual time engaged in utility operations or on a representative time study, and to maintain data supporting distribution of the labor to operating costs. Audit staff found that Duke Companies' charges of lobbying and support staff labor to operations were neither based on actual time engaged in utility operations nor derived from representative time studies, as required. The companies also did not maintain data supporting distribution of the costs to utility operations. Duke Companies' accounting for lobbying labor time charges was not consistent with Commission accounting requirements and could have resulted in the inclusion of inappropriate costs in operating accounts, and consequently, in charges to transmission service formula rate and wholesale requirements customers. This could have led to the overcharging of wholesale ratepayers.

Recommendations

We recommend Duke Companies:

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support

staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of receiving the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

30. Implement policies and procedures to perform a labor time study at least biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

8. Nonutility Expenses in Operating Accounts

Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

Pertinent Guidance

Accounting Release 12, Discriminatory Employment Practices, states in part:

Expenditures resulting from employment practices found to be discriminatory by a judicial or administrative decree or that were the result of a compromise settlement or consent decree are not just and reasonable cost of utility operations and as such must be charged to nonoperating expense accounts.

18 C.F.R Part 101, Account 426.1, Donations, states:

This account shall include payments or donations for charitable, social, or community welfare purposes.

18 C.F.R. Part 101, Account 426.5, Other Deductions, states:

This account shall include other miscellaneous expenses for which are non-operating in nature, but which are properly deductible before determining total income before interest charges.

Background

Audit staff reviewed a sample of expenses charged to administrative and general (A&G) accounts to determine whether the charges were accounted for in accordance with Commission accounting requirements. The sample included charges to Accounts 920, Administrative and General Salaries, 923, Outside Services Employed, and 926, Employee Pensions and Benefits, in 2012. Audit staff reviewed accounting records and documentation supporting amounts reported in the accounts, such as invoices, work orders, and billings. Audit staff also interviewed Duke Companies' employees with responsibility for documenting and accounting for costs reported in the accounts.

Audit staff's review found that Duke Companies accounted for $100,000 of expenditures resulting from employment practices found to be discriminatory as operating expenses. However, in accordance with the requirements of Accounting Release 12, Discriminatory Employment Practices, expenses of this nature should be accounted for as nonoperating expenses. Of the $100,000, audit staff found that $40,000 was improperly recorded to Account 923 and inappropriately included in transmission formula rate determinations. The remaining $60,000 was incorrectly accounted for in production and distribution operating accounts, including Accounts 519, Coolants and Water, 524, Miscellaneous Nuclear Power Expenses, and 583, Overhead Line Expenses. The costs should have been charged to Account 426.5, Other Deductions, consistent with the instructions of the account. Account 426.5 provides for recording expenses that are nonoperating in nature, and are properly deductible before determining total income before interest charges.

Further, audit staff also found that Duke Companies improperly charged about $39,000 in costs related to donations and charitable contributions to above-the-line operating accounts rather than Account 426.1, Donations, as required. Account 426.1 provides for reporting payments or donations for charitable, social, or community welfare purposes. The sampled invoices that audit staff reviewed included expenditures for charity-related activities that were improperly charged to operating accounts.

Because audit staff's review involved a select, small sample of transactions out of a larger population of transactions that involved expenses charged to Accounts 920, 923, and 926, audit staff believes that review of a larger number of transactions charged to these accounts may have revealed additional accounting errors that could have resulted in inappropriate charges to wholesale power and transmission formula rate customers. Duke Companies represented that they performed an analysis of all charges to the 900 series expense accounts for April 2014 through December 2014, and estimated that they incorrectly accounted for approximately $490,000 of costs in the accounts in 2014. These errors are the result of Duke Companies' lack of documented policies and insufficient training of employees on Commission requirements pertaining to accounting for nonoperating expenses. Employees with responsibility for recording expenses of this nature should have knowledge of the importance of appropriate accounting and the impact of improper accounting on rates charged through transmission formula rates.

Recommendations

We recommend Duke Companies:

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to A&G accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

35. Submit a refund analysis, within 60 days of receiving the final audit report, for review to DAA that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Appendix: Duke Energy's Comments on Audit Report

DUKE ENERGY.

Brian D. Savoy
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March 30, 2016

Mr. Bryan K. Craig
Director and Chief Accountant
Division of Audits and Accounting
Office of Enforcement
Federal Energy Regulatory Commission
888 First Street NE, Room 5K-13
Washington, DC 20426

RE: Office of Enforcement
Docket No. PA14-2-000
Duke Energy Corporation

Dear Mr. Craig:

On February 19, 2016, the Division of Audits and Accounting ("DAA") within the Office of Enforcement of the Federal Energy Regulatory Commission (the "Commission") issued a draft audit report setting forth the DAA's findings and recommendations resulting from the audit of Duke Energy Corporation ("Duke Energy") and its public utility subsidiaries' compliance with (1) conditions in Commission merger authorization orders, (2) transmission formula rate tariff requirements, and (3) accounting and financial reporting regulations. After several constructive discussions between DAA staff and Duke Energy, the draft audit report was revised several times. DAA staff sent the latest revision to Duke Energy dated March 29, 2016. Duke Energy is responding to the March 29 revision.

SUMMARY

In the draft audit report as revised, the DAA made eight findings and 37 associated recommendations. In sum, Duke Energy accepts five of the eight findings and all associated recommendations. Duke Energy respectfully disagrees with, but will not contest, two of the eight findings (findings 2 and 3) and agrees to comply with all associated recommendations. Duke Energy disagrees with a portion of, but will not contest under 18 CFR Part 41, one of the eight findings (finding 5) and all recommendations as they apply to the portion with which it disagrees, and accepts in part finding 5 and all recommendations as they apply to the accepted portion.

RESPONSE TO FINDINGS

In accordance with the procedures set forth in 18 C.F.R. 41.1, Duke Energy responds to each of the findings as follows:

- **Finding 1.** *Accounting for Merger Transaction Costs* – Duke Companies did not file merger transaction accounting entries with the Commission as required by the Merger Order, and the companies recorded merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. By not filing the accounting entries, Duke Companies prevented Commission review of the merger accounting and correction of any entries that were not in accordance with Commission accounting requirements.

Response: Duke Energy accepts this finding.

- **Finding 2.** *Merger Transaction Internal Labor Costs* – Duke Companies improperly included approximately $31.4 million of merger transaction internal labor costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating that the costs were offset by quantified savings produced by the merger. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated an estimated $17.5 million.

Response: Duke Energy respectfully disagrees with this finding, but will not contest it. For the purpose of establishing a complete record, Duke Energy explains its position as follows.

Duke Energy acknowledges its obligation to hold transmission and wholesale power customers harmless for five years from costs related to the merger of Duke Energy and Progress Energy, Inc. (the "Merger").

Between the time of the Commission's Merger Order issued on September 30, 2011 and the closing of the Merger on July 2, 2012, Duke Energy determined that its hold harmless commitment is intended to apply to costs caused by the Merger ("Incremental Costs") and not to costs that would have been incurred even in the absence of the Merger ("Non-Incremental Costs"). No Commission orders squarely addressed this issue, and it seemed to be inherent in the nature of a *hold harmless* commitment that it would protect customers only from costs that they would not have incurred otherwise.

On the basis of this logic, Duke Energy did not treat as transaction-related costs any portion of the regular compensation that employees would have received in the absence of the Merger even if the employees spent some of their time working on transaction-related activities. The company would have paid those same salaries to the employees with or without the Merger. Thus the regular compensation of employees was viewed as Non-Incremental Costs. On the other hand, Duke Energy did treat as transaction-related costs any compensation paid to employees that would *not* have been incurred but for the Merger. For example, this included any bonuses paid to employees in recognition of the extended hours many employees worked to fulfill their regular duties and to work on merger activities. It also included temporary employees and contractors hired to backfill for work that could not be absorbed in this manner. These costs were viewed as Incremental Costs and accordingly were excluded from FERC-jurisdictional rates.

Treatment of internal labor costs in the context of a hold harmless obligation was certainly not a settled issue in early 2012 or even today. This uncertainty was reflected in the Commission's notice of proposed *Policy Statement on Hold Harmless Commitments* issued January 22, 2015 in Docket No. PL15-3. In this notice of proposed policy statement issued two and a half years after the closing of the Merger, the Commission states as follows:

> "...we propose to clarify those costs to which hold harmless commitments will apply. Although the Commission has provided broad guidance regarding the costs that should be covered under hold harmless commitments, it has never defined those costs with much specificity, leading to inconsistency with respect to this issue."[1]

The Commission proposed to clarify that internal labor costs should be treated as transaction-related costs and stated as follows:

> "If the duties of employees are not solely dedicated to activities related to a transaction, internal labor costs deemed merger-related should be determined in a manner that is proportionally equal to the amount of time spent on the merger compared to other activities of the utility and tracked accordingly."[2]

While this *proposal* is clear on this issue, it is worth repeating that it was issued two and a half years after the Merger closed. It is also important to note that it is just a proposal at this time because the final policy statement has not been issued. In addition, some commenters specifically disagreed with this point.[3] Finally, the Commission stated in the notice of proposed policy statement that it would have prospective effect only.[4]

Notwithstanding Duke Energy's belief that its failure to exclude from rates Non-Incremental internal labor costs was not a violation of any settled policy and in fact was based on the most reasonable interpretation of its hold harmless commitment, Duke Energy will not expend the resources necessary to contest this issue and will comply with all associated recommendations in the audit report. Duke Energy reserves all rights in the event that the Commission issues an order

[1] Paragraph 16 of the notice of proposed policy statement.
[2] Footnote 41 of the notice of proposed policy statement.
[3] See the comments of Edison Electric Institute filed on March 30, 2015 at p. 15-16.
[4] Paragraph 20 of the notice of proposed policy statement.

in the proposed policy statement proceeding or any other proceeding that is not consistent with Finding 2.
Duke Energy estimates that the total refunds that will be due to transmission and wholesale power customers arising from this finding will be approximately $1.2 million plus interest.

- **Finding 3.** *Merger Transaction Outside Services and Related Costs* – Duke Companies incorrectly included $1.5 million of merger transaction outside services and related costs in wholesale power and transmission formula rate service cost determinations without first submitting a section 205 filing demonstrating the costs were offset by quantified savings produced by the merger. In addition, the companies recorded the merger transaction costs in operating accounts, contrary to the Commission's long-standing policy that such costs be recorded in nonoperating accounts. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated an estimated $745,000.

Response: Duke Energy respectfully disagrees with this finding, but will not contest it. For the purpose of establishing a complete record, Duke Energy explains its position as follows.

The costs which are the subject of this finding are costs incurred in 2010 to investigate, agree to, and perform preliminary due diligence regarding, the Merger prior to the announcement of the Merger. Duke Energy made the determination that its hold harmless commitment was not intended to include such costs incurred during the formative stage of a potential transaction before it was clear that the company would even pursue the transaction. Like most utility holding companies, Duke Energy has a corporate development group that regularly investigates and reviews potential transactions as part of its routine operations. Only a very small percentage of potential transactions reviewed are ever consummated. In order to comply with a hold harmless commitment as interpreted in this Finding 3 for a transaction that is eventually consummated, the company would have to track all its costs for each and every potential transaction it reviews even though the vast majority will never be consummated. This would be unwieldy and wasteful. Because these potential transactions often will benefit customers, discouraging investigation of them is not in the best interests of customers.

Treatment of such investigation costs incurred prior to the announcement of a transaction in the context of a hold harmless obligation was certainly not a settled issue in early 2012 or even today. This uncertainty was reflected in the Commission's notice of proposed *Policy Statement on Hold Harmless Commitments* discussed in Duke Energy's response to Finding 2 above.

In the notice of proposed policy statement, the Commission proposed to clarify that such investigation costs would be subject to the hold harmless commitment.[5]

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[5] Paragraph 22 of the notice of proposed policy statement.

As in Duke Energy's response to Finding 2 above, we will point out again that the notice of proposed policy statement was issued two and a half years after the Merger closed, and is just a proposal at this time because the final policy statement has not been issued. In addition, some commenters specifically disagreed with this point.[6]

Notwithstanding Duke Energy's belief that its failure to exclude pre-announcement costs that are the subject of Finding 3 was not a violation of any settled policy, Duke Energy will not expend the resources necessary to contest this issue and will comply with all associated recommendations in the audit report.

Duke Energy estimates that the total refunds that will be due to transmission and wholesale power customers arising from this finding will be approximately $60,000 plus interest.

- **Finding 4.** *Use of the Consolidation Method of Accounting* – DEC and DEP accounted for investments in subsidiaries on a consolidated basis in their FERC Form No. 1, Annual Reports (Form No. 1), contrary to the Commission's long-standing accounting policy.

Response: Duke Energy accepts this finding.

- **Finding 5.** *Accounting for Sales of Accounts Receivable* – DEC, DEP, and DEF misclassified an estimated $94.7 million of nonoperating expenses and receivables arising from transactions with their subsidiaries during the audit period. As a result, the wholesale power and transmission customers' revenue requirements were inappropriately overstated by an estimated $61 million.

Response: Duke Energy disagrees with the portion of this finding that concerns accounting for losses on the sale of receivables. However, Duke Energy will not contest this finding under 18 CFR Part 41 because the portion of this finding that relates to accounting for losses on the sale of receivables, including recommendations 17 and 18, will be held in abeyance and will be subject to the outcome of Duke Energy's request for rehearing in Docket No. AC15-174-001 pursuant to the draft audit report.

- **Finding 6.** *Accounting for Lobbying Expenses:* Duke Companies recorded approximately $2.4 million of lobbying expenses in above-the-line operating accounts from 2011 through 2013. As a consequence, Duke Companies improperly included these costs in wholesale power and transmission formula rate service cost determinations.

Response: Duke Energy accepts this finding.

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[6] See the comments of Edison Electric Institute filed March 30, 2015 at p. 14-15.

- **Finding 7.** *Allocation of Lobbyist Labor Costs:* Duke Companies accounted for the labor costs of internal lobbyists and their support staff in operating accounts that lacked support for inclusion in the accounts. Improper accounting for the costs can lead to inappropriate recovery of the costs through rates charged and billed to customers.

Response: Duke Energy accepts this finding.

- **Finding 8.** *Nonutility Expenses in Operating Accounts:* Duke Companies recorded approximately $490,000 of nonutility expenses in operating accounts in 2014. As a result, inappropriate costs were included in wholesale power and transmission formula rate service cost determinations and charged to customers.

Response: Duke Energy accepts this finding.

RESPONSE TO RECOMMENDATIONS

Duke Energy will comply with all recommendations except as otherwise stated below. As requested, Duke Energy proposes target completion dates below for each recommendation wherever the recommendation does not specify the completion date.

Accounting for Merger Transaction Costs

1. Revise accounting policies and procedures to appropriately account for merger transactions consistent with Commission accounting requirements.

Target Completion Date: September 30, 2016

2. Develop written policies and procedures to timely identify proposed accounting transactions that would trigger a notification to the Commission.

Target Completion Date: September 30, 2016

3. Develop written policies and procedures to submit accounting questions of doubtful interpretation to the Commission.

Target Completion Date: September 30, 2016

4. Provide training to employees on compliance with the merger cost accounting conditions and the revised policies, procedures, and controls for complying with the conditions. Also, develop a training program that supports the provision of periodic training in this area.

Target Completion Date: December 31, 2016

Merger Transaction Internal Labor Costs

If the Commission issues a policy statement on hold harmless commitments and such policy statement is inconsistent with Finding 2 or Finding 3, then Duke Energy reserves the right to seek relief from compliance with any of recommendations 5 – 12 as appropriate.

5. Revise all policies and procedures for tracking, accounting, and excluding merger transaction costs from wholesale power and transmission formula rates, including amounts previously charged to utility plant, accumulated deferred income taxes, construction work in progress with the associated capitalized cost of funds used during construction (AFUDC), and maintenance and operating expense accounts, and future charges to such accounts for any transaction to which a FERC hold harmless obligation applies. The revised procedures should hold customers harmless from all merger transaction costs consistent with requirements of the Merger Order. Among other things, the revised policies and procedures should include an annual review of each subsidiary's merger transaction cost adjustments as well as periodic evaluations within the year, as needed and appropriate.

Target Completion Date: September 30, 2016

6. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction internal labor and related costs in wholesale power and transmission formula rates during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

7. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

8. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Merger Transaction Outside Services and Related Costs

9. Revise accounting policies and procedures to appropriately account for merger transaction costs consistent with Commission accounting requirements.

Target Completion Date: September 30, 2016

10. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the inclusion of merger transaction outside services and related costs in wholesale power and transmission formula rate charges during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

11. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

12. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Use of the Consolidation Method of Accounting

13. Review and, as needed, revise accounting policies, practices, and procedures to ensure that investments in subsidiaries are accounted for consistent with the Commission's equity method accounting requirements.

Response and Target Completion Date: Duke Energy will comply with this recommendation, but notes that the Commission has granted to DEC, DEP, and DEF a waiver from the requirement to use the equity method as discussed above. Target Completion date is 60 days after receiving the final audit report.

14. Evaluate the accounting applied to Duke Companies' existing subsidiaries and notify DAA of any areas of noncompliance with Commission accounting requirements.

Target Completion Date: 60 days after receiving the final audit report.

15. Revise documented policies, procedures and processes to ensure timely notice is provided to relevant regulators regarding instances of noncompliance with regulations, rules, and orders.

Target Completion Date: September 30, 2016

16. Provide training to staff on procedures, practices, and available tools to transparently or anonymously report instances of noncompliance to senior management, the Board of Directors, and relevant regulators.

Target Completion Date: December 31, 2016

Accounting for Sales of Accounts Receivable

17. Revise procedures to ensure that all costs, revenues, and account balances associated with the sale of accounts receivable are accounted for in accordance with Commission accounting regulations. Among other things, the corrected accounting should ensure that all discounts, fees, and revenues associated with receivable sales are recorded in Account 426.5, and that the cost of performing collection services on behalf of the subsidiaries, including employee labor, expenses, and an appropriate allocation of overhead and utility plant, are recorded in Account 426.5.

Response and Target Completion Date: In accordance with the draft audit report, the portions of this recommendation that relate to accounting for losses on the sale of receivables are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for review proceedings. The target completion date for portions that do *not* relate to accounting for losses on the sale of receivables is 60 days after receiving the final audit report.

18. Provide the revised procedures to DAA for review within 60 days of receiving the final audit report.

Response and Target Completion Date: In accordance with the audit report, the portions of this recommendation that relate to accounting for losses on the sale of receivables are held in abeyance and subject to the outcome of the rehearing request and any subsequent petitions for review proceedings.

19. Recalculate charges to wholesale power and transmission customers of DEC, DEP, and DEF and submit the recalculations in a refund analysis to DAA for review within 60 days of receiving the final audit report. The refund analysis should explain and detail the: (1) return of collection service billings charged in 2014; (2) return of losses on the sales included in rates; (3) determinative components of the refund; (4) refund method; (5) period(s) refunds will be made; and (6) interest calculated in accordance with section 35.19 of Commission regulations.

20. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

21. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Accounting for Lobbying Expenses

22. Establish and implement written procedures governing the methods used to account for, track, report, and review lobbying costs incurred.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

23. Provide training on Commission accounting requirements and the impact of accounting on cost-of-service rate determinations to employees involved in lobbying and lobbying-related work, and those with oversight responsibility for lobbying cost allocations. Also, develop a training program that supports the provision of periodic training in this area.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

24. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of lobbying cost in operating accounts during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made.

25. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

26. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Allocation of Lobbyist Labor Costs

27. Revise written policies and procedures to create a process to document and verify appropriate allocation of lobbying and lobbying-related costs, and maintain auditable support for the cost included in rate determinations.

Response: Duke Energy has completed this action. Duke Energy will update its procedures upon completion of the labor time study referenced in recommendation 28.

28. Retain an independent third-party entity to conduct a representative labor time study to determine an appropriate allocation of internal lobbyist labor, support staff, and associated costs that should be accounted for in operating and nonoperating accounts based on time spent by employees engaged in the activities. Provide the study results to audit staff within 180 days of the date of the final audit report.

29. Include the results of the labor time study in the determination of lobbying-related labor cost allocations as of January 1, 2016.

Target Completion Date: 180 days after the date of the final audit report

30. Implement policies and procedures to perform a labor time study biennially using an independent third-party or internal company resources that are able to attest to the results of the study. Revise the lobbying-related labor cost allocations based on the results of the study.

Target Completion Date: 180 days after the date of the final audit report

Nonutility Expenses in Operating Accounts

31. Develop and implement written policies, procedures, and controls to ensure proper accounting and reporting of nonutility expenses.

Response: Duke Energy has completed this action.

32. Provide training for employees involved in the invoicing process on Commission accounting requirements and the impact of the accounting on cost-of-service rate determinations.

Response: Duke Energy has completed this action.

33. Within 60 days of receiving the final audit report, provide documentation supporting the analysis performed of invoiced expenses recorded to administrative and general (A&G) accounts in 2014 that identified misclassified nonutility expenses included in A&G accounts. Develop an estimate of misclassified nonutility expenses accounted for in operating accounts in 2011 through 2013 and 2015.

34. Implement policies and procedures to provide periodic audits or reviews of A&G transactions by external or internal auditors.

Target Completion Date: 60 days after the date of the final audit report

35. Submit a refund analysis, within 60 days of receiving the final audit report, to DAA for review that explains and details the following: (1) calculation of refunds that include the amount of inappropriate recoveries that resulted from the improper inclusion of identified and estimated nonutility expenses in charges to wholesale power and transmission customers during the audit period, plus interest on the costs; (2) determinative components of the refund; (3) refund method; and (4) period(s) refunds will be made. Include the results of the invoice analysis in the refund analysis.

36. File a refund report with the Commission after receiving DAA's assessment of the refund analysis.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

37. Refund amounts disclosed in the refund report to wholesale power and transmission customers, with interest calculated in accordance with section 35.19a of Commission regulations.

Target Completion Date: 45 days after receiving DAA's assessment of the refund analysis

Duke Energy acknowledges and appreciates the professionalism and the courtesy with which DAA staff conducted this audit.

Sincerely,

Brian D Savoy by Paul King

Brian D. Savoy
Senior Vice President, Chief Accounting
Officer and Controller