COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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

CASE NO. 2022-00372

FILING REQUIREMENTS

VOLUME 13

Duke Energy Kentucky, Inc.
Case No. 2022-00372
Forecasted Test Period Filing Requirements
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Vol. #	Tab #	Filing Requirement	Description	Sponsoring Witness
1	1	KRS 278.180	30 days' notice of rates to PSC.	Amy B. Spiller
1	2	807 KAR 5:001 Section 7(1)	The original and 10 copies of application plus copy for anyone named as interested party.	Amy B. Spiller
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. (i) Detailed income statement and balance sheet.	Christopher R. Bauer Danielle L. Weatherston
1	4	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.	Amy B. Spiller
1	5	807 KAR 5:001 Section 14(2)	If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state if it is authorized to transact business in Kentucky.	Amy B. Spiller

1	6	807 KAR 5:001 Section 14(3)	If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state if it is authorized to transact business in Kentucky.	Amy B. Spiller
1	7	807 KAR 5:001 Section 14(4)	If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.	Amy B. Spiller
1	8	807 KAR 5:001 Section 16 (1)(b)(1)	Reason adjustment is required.	Amy B. Spiller Sarah E. Lawler
1	9	807 KAR 5:001 Section 16 (1)(b)(2)	Certified copy of certificate of assumed name required by KRS 365.015 or statement that certificate not necessary.	Amy B. Spiller
1	10	807 KAR 5:001 Section 16 (1)(b)(3)	New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed	Bruce L. Sailers
1	11	807 KAR 5:001 Section 16 (1)(b)(4)	Proposed tariff changes shown by present and proposed tariffs in comparative form or by indicating additions in italics or by underscoring and striking over deletions in current tariff.	Bruce L. Sailers
1	12	807 KAR 5:001 Section 16 (1)(b)(5)	A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice.	Amy B. Spiller
1	13	807 KAR 5:001 Section 16(2)	If gross annual revenues exceed $5,000,000, written notice of intent filed at least 30 days, but not more than 60 days prior to application. Notice shall state whether application will be supported by historical or fully forecasted test period.	Amy B. Spiller
1	14	807 KAR 5:001 Section 16(3)	Notice given pursuant to Section 17 of this administrative regulation shall satisfy the requirements of 807 KAR 5:051, Section 2.	Amy B. Spiller
1	15	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.	Grady “Tripp” S. Carpenter
1	16	807 KAR 5:001 Section 16(6)(b)	Forecasted adjustments shall be limited to the twelve (12) months immediately following the suspension period.	Grady “Tripp” S. Carpenter Lisa D. Steinkuhl Huyen C. Dang
1	17	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.	Lisa D. Steinkuhl
1	18	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.	Grady “Tripp” S. Carpenter

1	19	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.	Grady "Tripp" S. Carpenter
1	20	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.	Lisa D. Steinkuhl
1	21	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	22	807 KAR 5:001 Section 16(7)(b)	Most recent capital construction budget containing at minimum 3 year forecast of construction expenditures.	Grady "Tripp" S. Carpenter Dominic "Nick" J. Melillo William C. Luke
1	23	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.	Grady "Tripp" S. Carpenter
1	24	807 KAR 5:001 Section 16(7)(d)	Annual and monthly budget for the 12 months preceding filing date, base period and forecasted period.	Grady "Tripp" S. Carpenter
1	25	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.	Amy B. Spiller
1	26	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.	Grady "Tripp" S. Carpenter Dominic "Nick" J. Melillo William C. Luke
1	27	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.	Grady "Tripp" S. Carpenter Dominic "Nick" J. Melillo William C. Luke

1	28	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.	Grady “Tripp” S. Carpenter Max W. McClellan John D. Swez
1	29	807 KAR 5:001 Section 16(7)(i)	Most recent FERC or FCC audit reports.	Danielle L. Weatherston
1	30	807 KAR 5:001 Section 16(7)(j)	Prospectuses of most recent stock or bond offerings.	Christopher R. Bauer
1	31	807 KAR 5:001 Section 16(7)(k)	Most recent FERC Form 1 (electric), FERC Form 2 (gas), or PSC Form T (telephone).	Danielle L. Weatherston
2	32	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.	Christopher R. Bauer
3	33	807 KAR 5:001 Section 16(7)(m)	Current chart of accounts if more detailed than Uniform System of Accounts charts.	Danielle L. Weatherston
3	34	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.	Danielle L. Weatherston
3	35	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.	Grady “Tripp” S. Carpenter Danielle L. Weatherston
3-8	36	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.	Danielle L. Weatherston
8	37	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.	Danielle L. Weatherston
8	38	807 KAR 5:001 Section 16(7)(r)	Quarterly reports to the stockholders for the most recent 5 quarters.	Christopher R. Bauer

8	39	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
8	40	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	Lisa D. Steinkuhl
8	41	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
9	42	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
9	43	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
9	44	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.	Lisa D. Steinkuhl

9	45	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.	Lisa D. Steinkuhl Huyen C. Dang Grady "Tripp" S. Carpenter John R. Panizza James E. Ziolkowski Danielle L. Weatherston
9	46	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.	Lisa D. Steinkuhl
9	47	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.	Lisa D. Steinkuhl Grady "Tripp" S. Carpenter Huyen C. Dang James E. Ziolkowski
9	48	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.	John R. Panizza
9	49	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.	Lisa D. Steinkuhl
9	50	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.	Lisa D. Steinkuhl Jacob J. Stewart
9	51	807 KAR 5:001 Section 16(8)(h)	Computation of gross revenue conversion factor for forecasted period.	Lisa D. Steinkuhl
9	52	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.	Danielle L. Weatherston Grady "Tripp" S. Carpenter
9	53	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.	Christopher R. Bauer
9	54	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.	Huyen C. Dang Danielle L. Weatherston Christopher R. Bauer Grady "Tripp" S. Carpenter
9	55	807 KAR 5:001 Section 16(8)(l)	Narrative description and explanation of all proposed tariff changes.	Bruce L. Sailers
9	56	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
9	57	807 KAR 5:001 Section 16(8)(n)	Typical bill comparison under present and proposed rates for all customer classes.	Bruce L. Sailers
9	58	807 KAR 5:001 Section 16(9)	The commission shall notify the applicant of any deficiencies in the application within thirty (30) days of the application's submission. An application shall not be accepted for filing until the utility has cured all noted deficiencies.	Sarah E. Lawler

9	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.	N/A
9	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.	Amy B. Spiller
9	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.	Amy B. Spiller

9	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.	Amy B. Spiller

9	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
9	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

10	-	807 KAR 5:001 Section 16(8)(a) through (k)	Schedule Book (Schedules A-K)	Various
11	-	807 KAR 5:001 Section 16(8)(l) through (n)	Schedule Book (Schedules L-N)	Bruce L. Sailers
12	-	-	Work Papers	Various
13	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 1 of 3)	Various
14	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 2 of 3)	Various
15	-	807 KAR 5:001 Section 16(7)(a)	Testimony (Volume 3 of 3)	Various
16-17	-	KRS 278.2205(6)	Cost Allocation Manual	Legal

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

AMY B. SPILLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

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

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as State President of Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and its parent, Duke Energy Ohio, Inc. (Duke Energy Ohio). DEBS provides various administrative and other services to Duke Energy Kentucky and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I received a bachelor's degree in economics and management from Albion College in Michigan and a law degree from Wake Forest University in Winston-Salem, N.C. Following law school, I spent two years working for Business Laws, Inc., a legal publishing company in northeast Ohio. Then, from 1993 to 2003, I rose from associate to partner at Wilson & Markesbery Co., L.P.A., a small insurance defense law firm in Cincinnati, Ohio.

I joined Cinergy Corp., (Cinergy) in 2003 as an associate general counsel, focusing on litigation matters. In 2008, following the 2006 merger between Cinergy and Duke Energy, I was promoted to deputy general counsel, assuming responsibility relative to Duke Energy's strategic planning in Ohio and Kentucky. I was also responsible for advancing Duke Energy's rate and regulatory initiatives before the Public Utilities Commission of Ohio and the Kentucky Public Service Commission (Commission). In January 2018, I was named Vice President of Government and Community Affairs for Duke Energy Ohio, where I was responsible for managing state government and regulatory policies, strategies, and relationships affecting Duke Energy Ohio's interests and those of our Ohio customers. On June 1, 2018, I was named to my current position of State President, Duke Energy Ohio and Duke Energy Kentucky.

Q. PLEASE DESCRIBE YOUR DUTIES AS STATE PRESIDENT, DUKE ENERGY KENTUCKY.

A. As State President, Duke Energy Kentucky, I am responsible for ensuring that our customers continue to have access to adequate, efficient, and reasonable electric and natural gas service at a fair, just, and reasonable rate and that these services are provided in accordance with applicable federal and state laws and regulations. I am also involved in external efforts relating to governmental and regulatory affairs, interacting with state and community leaders and regulators on matters relevant to Duke Energy Kentucky's business and presence in the Commonwealth. Finally, I am responsible for the Company's community relations and economic development efforts, as well as Duke Energy's charitable contributions in the Northern Kentucky and southwest Ohio.

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

A. Yes. I have previously testified before the Commission.

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

A. My testimony provides an overview of Duke Energy Kentucky's electric business operations and community involvement in our Northern Kentucky service territory. I discuss Duke Energy Kentucky's levels of customer satisfaction and how the constructive regulatory treatment sought in this proceeding will enable the Company to meet our customers' ever-changing expectations for adequate, efficient, and reasonable service at a fair, just, and reasonable rate.

I next provide an overview of Duke Energy Kentucky's need for an increase in electric rates and the reasonableness of this request. In this regard, I address proposals in our Application that support regional development and growth, while acknowledging – and responding to – our customers' expectations around the services we provide and adapting to a changing energy landscape. Among other initiatives, the Company is proposing within this Application the following: 1) a Clean Energy Connection program for customers desiring to source their generation from renewable resources; 2) new electric vehicle (EV) programs to support EV development; 3) a new dynamic time of use rate for residential customers; 4) a new Generating Asset True-up Mechanism to reconcile undepreciated plant balances following future retirements; 5); enhancements to the LED tariff; 6) enhancements to our economic development rider (Rider DIR) to increase the flexibility of potential development incentive offers and enhance the potential benefit to the prospective customer; 7) a reduction in the late payment charge; and, 8) a process for enabling incremental system investments required by local ordinance and recovery of costs incurred thereby.

The Company is also proposing to 1) update depreciation rates to align the depreciable lives of our generating plants with their service lives; 2) revise the fuel adjustment mechanism (Rider FAC) to reduce volatility in customer rates; and 3) roll rate base in the environmental surcharge mechanism (Rider ESM) into base rates. Rider ESM will continue to recover Asset Retirement Obligations (ARO) costs, emission allowances and reagents. Finally, the Company is also introducing a lead/lag study to support cash working capital in this proceeding.

I also introduce the other witnesses who testify on the Company's behalf and, in doing so, provide an overview of their testimony. I sponsor several Filing Requirements (FR), including those mandated under 807 KAR 5:001: FR 7(1), FR 14(1) through FR 14(4), FR 16(1)(b)(1), FR 16(1)(b)(2), FR 16(1)(b)(5), FR 16(2), and FR 16(3). I discuss the existing programs designed to improve efficiency and productivity and the purpose of each program, as required by FR 16(7)(a). I provide the management statement of attestation, required by FR 16(7)(e), concerning the forecasted financial data. Additionally, I sponsor the affidavit in support of the notice requirements under FR 17(1) through (3). Finally, I sponsor the pre-filing notice as required by KRS 278.180.

II. OVERVIEW OF KENTUCKY OPERATIONS

A. COMPANY OVERVIEW

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S UTILITY OPERATIONS IN NORTHERN KENTUCKY.

A. Duke Energy Kentucky provides electric service to approximately 149,200 customers and natural gas service to approximately 103,100 customers in Bracken (gas only), Boone, Campbell, Gallatin (gas only), Grant, Kenton, and Pendleton counties in Northern Kentucky.

From our Cincinnati headquarters, Duke Energy Kentucky directs the planning, construction, operation, and maintenance of our electric transmission and distribution systems. The Company's electric customers are served via an electric transmission and distribution system operated in accordance with good utility practice as further described by Duke Energy Kentucky witness Nick J. Melillo. Most customers continue to be served via overhead transmission and distribution lines; however, the Company is increasingly serving customers with underground facilities.

The Company's local electric operations are as follows:

- Cincinnati, Ohio – the headquarters for Duke Energy Kentucky
- Rabbit Hash, Kentucky – the East Bend Generating Station
- Trenton, Ohio – the Woodsdale Generating Station
- Erlanger, Kentucky – Duke Energy Kentucky's construction and maintenance facility
- Covington, Kentucky – Duke Energy Kentucky's meter reading facility

- Harrison, Ohio – Duke Energy Kentucky and Ohio's Electric System Operations Facility

From these locations, Duke Energy Kentucky generates electricity; provides for the construction, operation, and maintenance of our electric delivery system; and conducts our business operations.

Q. PLEASE PROVIDE AN OVERVIEW OF THE DUKE ENERGY CORPORATE AND BUSINESS STRUCTURE.

A. Duke Energy is one of the largest utility companies in the United States. Through a series of mergers and acquisitions, including the 2006 merger with Cinergy, the 2012 merger with Progress Energy, and the more recent merger with Piedmont Natural Gas Company, Duke Energy now serves approximately 8.2 million electric customers and over 1.6 million natural gas customers in seven states, comprising Kentucky, Ohio, Indiana, Florida, North Carolina, South Carolina, and Tennessee.

Duke Energy Kentucky is a wholly owned subsidiary of Duke Energy Ohio. Duke Energy Ohio is a wholly owned subsidiary of Cinergy, which is wholly owned by Duke Energy.

Q. PLEASE DESCRIBE HOW BEING A PART OF THE DUKE ENERGY FAMILY OF COMPANIES ASSISTS DUKE ENERGY KENTUCKY IN PROVIDING ADEQUATE, EFFICIENT, AND REASONABLE SERVICE AT A FAIR, JUST, AND REASONABLE RATE FOR ITS KENTUCKY CUSTOMERS.

A. As further explained by Duke Energy Kentucky witness Jeffrey R. Setser, Duke Energy Kentucky is a party to multiple Commission-approved affiliate service agreements that provide the Company with access to a vast level of resources, experience, and expertise beyond what Duke Energy Kentucky could achieve as a stand-alone utility.[1] These various agreements include, among other things, a service company/operating company agreement and an operating company agreement. Under the former, Duke Energy Kentucky and, by extension, our customers, benefit from the defined pool of highly skilled attorneys, accountants, engineers, customer service representatives, and other professionals whose time and cost are shared among all utility affiliates within Duke Energy. Under the latter agreement, Duke Energy Kentucky and our customers benefit from the services provided by affiliated utility companies that furnish natural gas and electric service in seven states.

Consequently, Duke Energy Kentucky's customers have access to resources, including a highly trained and dedicated workforce from multiple jurisdictions, that are familiar with the Company's systems and are experienced in

[1] The Commission approved these services agreements in Case No. 2005-00228, involving the Duke Energy/Cinergy merger, again in Case No. 2011-00124 involving the merger between Duke Energy and Progress Energy, and most recently in Case No. 2016-00312 to incorporate Piedmont as an affiliate party to these agreements.

the safe operation of the Company's utility infrastructure, thereby enabling the continued and efficient operation of Duke Energy Kentucky's utility system. Pursuant to Commission-approved service agreements, Duke Energy Kentucky is allocated only a portion of these costs. Although this structure affords significant benefit to our customers, it is not a structure with which they have reason to take notice. Indeed, the legal entity structure and relationships discussed above are essentially invisible to and seamless for our Kentucky customers, who receive all their utility services from Duke Energy Kentucky. This corporate structure is designed such that our Kentucky customers will continue to receive adequate, efficient, and reasonable service at a fair, just, and reasonable rate without regard to corporate structure or organization.

B. COMMUNITY ENGAGEMENT

Q. PLEASE GIVE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S ECONOMIC DEVELOPMENT ACTIVITIES.

A. Duke Energy Kentucky embraces our responsibility to promote economic development in the communities in which we do business. We appreciate that access to affordable, reliable utility service is a critical factor in a company's decision about where to locate or expand its facilities. Duke Energy Kentucky is well positioned to meet our customers' energy needs and attract job-creating industries and capital investment to our service territory. However, business clients need more than reliable utility service. They also need readily available building sites, access to state and local incentives, flexible workforce training programs, and proximity to a community of customers and business partners.

Duke Energy Kentucky assists in meeting these needs through partnerships with our local communities and the Commonwealth of Kentucky.

In 2021, Site Selection magazine named Duke Energy to its Top 10 Utilities in Site Selection for North America for the twentieth consecutive year. Additionally, Site Selection recognized Duke Energy's "Site Readiness" program as a best practice. This program is designed to improve large tracts of industrial land in the service territory, moving them closer to being "fully marketable." More specifically, the Company pays for a national site consultant to conduct the site evaluation and due diligence and to prepare a robust, comprehensive report that provides recommendations on site improvements and targeted industries to attract, along with labor statistics tied to the site. A local engineering firm secured by Duke Energy Kentucky provides a detailed analysis of the site's streams, wetlands, topography, and soils and conceptual drawings for how many acres are actually developable. The program also helps the local community and economic development professionals hone their skills around the highly competitive process of responding to requests for information from site consultants and prospects.

Since 2010, Site Readiness has been conducted with sixteen sites in our Duke Energy Kentucky footprint; six of which have seen substantial development, including the Amazon Air Hub facility in Boone County. Eight of the sixteen are still being actively marketed by Northern Kentucky Tri-ED and a seventeenth site is currently under evaluation in Campbell County. In addition to this successful program, our economic development team collaborates with local, regional, and state economic development professionals in attracting new business and jobs to our communities, whether in the field of Automotive, Aerospace and Defense, Batteries, Data Centers, Food and Beverage, Healthcare, Logistics, Manufacturing, or Life Sciences.

Duke Energy Kentucky's strategic partnerships and board memberships with local and regional economic development efforts such as the Regional Economic Development Initiative (REDI) Cincinnati and Northern Kentucky Tri-ED, combined with Duke Energy Kentucky’s competitive rates, have resulted in a number of economic development successes in Northern Kentucky.

We estimate that our cooperative efforts, along with those of state and local economic development officials, have contributed to the creation of nearly 35,213 jobs and more than $5.2 billion of capital investment in Northern Kentucky since 2006.

In addition to these partnerships, Duke Energy Kentucky advances economic development and community vibrancy through our Urban Revitalization Initiative. Since its inception in 2011, this initiative has provided over $3.2 million to support 100 projects in our Duke Energy Kentucky and Ohio service areas. These projects, located in the urban core, are designed to restore blighted, vacant properties, thereby enabling, among other things, commercial redevelopment and job creation. Around half of the funding over the past eleven years has supported projects in the Northern Kentucky River Cities of Bellevue, Covington, Dayton, Ludlow, and Newport.

Along with other Company leaders, I serve on various regional boards and organizations focused on promoted economic development as well as the related topics of workforce, transportation, and community vibrancy. This participation allows Duke Energy Kentucky to effectively support growth in the region and better understand the challenges and opportunities facing our customers. Some of the organizations in which Duke Energy Kentucky leaders have recently been or are currently involved include:

- Catalytic Funding Corp. of Northern Kentucky;
- Cincinnati Regional Business Committee;
- Cincinnati Center City Development Corporation;
- Cincinnati USA Regional Chamber of Commerce;
- Cintrifuse;
- European American Chamber of Commerce;
- Gateway Community & Technical College;
- GROW NKY;
- Horizon Community Funds of Northern Kentucky;
- Kentucky Association of Economic Development;
- Kentucky Chamber of Commerce;
- 1NKY Alliance;
- NKY Workforce Investment Board;
- Northern Kentucky Chamber of Commerce;
- Northern Kentucky Tri-ED;
- Ohio Business Roundtable;
- Ohio Chamber of Commerce;
- REDI Cincinnati;

- SW Ohio Regional Workforce Investment Board;
- The Port of Greater Cincinnati Development Authority;

Q. DESCRIBE DUKE ENERGY KENTUCKY'S CHARITABLE GIVING PHILOSOPHY.

A. Duke Energy Kentucky has made good corporate citizenship a priority by giving back to the communities we serve. Since 2016 alone, Duke Energy Kentucky and the Duke Energy Foundation have contributed over $4 million in shareholder dollars to Kentucky charitable organizations. In addition to our Urban Revitalization Initiative, these contributions have historically supported education, workforce, and nature. Increasingly, however, over the last several years, financial support has also been directed to victims of extreme weather events, including the Mayfield tornado and the recent flooding in Eastern Kentucky. Our philanthropic engagement is not only financial in nature. Rather, consistent with Duke Energy's culture of caring, our employees and retirees and their families regularly give back to our communities by volunteering their time. Indeed, from 2016 through this year, over 500 employees and retirees and their families volunteered over 17,487 hours of their time to help our local neighbors. Whether through playground renovation, cemetery improvements, tree planting, or painting, our employees and retirees, as well as their families, are continually giving back to our communities.

Q. DESCRIBE THE METHODS EMPLOYED BY DUKE ENERGY KENTUCKY TO ENGAGE WITH CUSTOMERS.

A. Our customers depend on the services we provide to power their lives. Moreover, in this very diverse and dynamic environment, it is important that our customers are able to engage with Duke Energy Kentucky via a variety of platforms. Consequently, we provide opportunities for customers to interact with the Company through various customer service channels, both directly and remotely. These programs include:

- Live residential and business customer care specialists;
- Intelligent Voice Response (IVR) system;
- Enhanced Web Functionality for Online Services;
- Focus Groups for small/medium businesses;
- Outbound calls, emails and texts;
- Pay Agents; and
- Social Media Customer Care

Q. DO CUSTOMERS HAVE OPTIONS FOR BOTH MANAGING AND PAYING THEIR BILLS?

A. Yes. Below I describe the various programs available for Duke Energy Kentucky customers to conveniently manage their bills commensurate with their individual circumstances. But before doing so, I wanted to address the significant efforts undertaken by the Company to share information about these programs during this period of significant market volatility.

Reports of higher utility bills have been common for the last year, with volatile fuel markets driving this upward pressure on customers' bills. Recognizing that commodity costs, which are a required pass-through item, and consumption contribute to fluctuations in our customers' bills, we have been very intentional in our efforts to inform customers of resources related to bill management and low and no-cost tools to reduce consumption. These communication efforts have included:

- Proactive news releases to local media and media interviews discussing high bills and assistance available;
- Digital "tool kits" to community organizations with fact sheets and energy saving tips;
- Distribution of "winter weatherization kits;"
- Bill messages, newsletters, social media and emails that direct customers to our web pages to a "High Bill" information web page;
- Paid promotions with educational messages on how customers can lower energy bills; and
- Partnerships with public transportation entities to display QR codes on public buses.

Our available bill management offerings include:

- Budget Billing: This program provides customers with predictable monthly payments and better control over their energy spending, which eases planning and budgeting. Customers who sign up for the free Budget Billing program may choose from two plans that adjust periodically based on actual energy usage. The Quarterly Plan provides a quarterly review and adjustment of the budget billing amount, preventing a settle-up month, while the Annual Plan also provides quarterly review and adjustment of the budget billing amount, but additional fluctuations are settled in the twelfth month;

- Duke Energy Mobile App and Website: The Company Website and mobile app for iPhone and Android devices provide a digital channel through which customers can manage their account, pay bills, and take advantage of products and services offered by Duke Energy;
- Extended Payment Agreements and Due Date Extensions: Customers have the option of entering into an Extended Payment Agreement with the Company. For example, the Company offers an Installment Plan option, allowing customers to spread out larger amounts due by making smaller monthly payments over a specified period. The Company also offers Due Date Extensions to provide flexibility to customers who know ahead of time they will not be able to pay their bill by the due date
- Paperless Billing: This program allows customers to receive a bill-ready reminder via email. When enrolling in the program, customers can select to either view and pay their bill online at duke-energy.com or through our mobile app or select to have a secure PDF copy attached to the bill reminder email. This program negates use of our standard paper bill that is mailed to the customer;

- Payment Confirmations: All email-registered customers are automatically enrolled to receive an email when their payment is received. Customers can choose to receive payment notifications via text message by updating their online account preferences;
- Pick Your Due Date (PYDD) and Preference Pay: PYDD is a program available to customers with AMI meters and was designed to offer our customers flexibility to meet their needs over the course of a year and beyond. Since AMI meters do not need to align with a specific meter reading schedule customers can select a date between 1 and 31 and the system will assign a meter-read cycle that most closely aligns with the selected due date. Preference Pay is an alternative option that allows residential customers who do not have an AMI meter to select their due date. Customers are able to choose from ten available due dates. For example, if a customer's actual due date is the fifth of each month, they may change their due date by as many as ten days, meaning they may change to a due date between the sixth and the fifteenth not counting weekend and holidays;
- Share the Light (formerly WinterCare): For decades, Duke Energy has aided qualifying customers who are struggling to pay their energy bills. Employees, customers, and Duke Energy shareholders contribute to these funds. In 2021, Duke Energy launched the Share the Light Fund, a new brand with structure enhancements and a streamlined customer digital experience. This program is designed to provide

heating assistance to those in need. The program is administered in partnership with the Northern Kentucky Community Action Commission using federal low-income guidelines, as well as true need, to determine program eligibility. Residential customer who are eligible may receive assistance of up to $300 per program year;

- Home Energy Assistance (HEA): This program provides another source of monthly bill assistance for eligible customers (up to 200 percent of the federal poverty level). Electric or combination electric and gas customers can receive up to $99 per month between January-April and July-September through the subsidy component and up to $400 is available for immediate assistance through the crisis component for customers who have a past-due balance and/or are in danger of disconnection. This program is funded through a combination of customer charges and shareholder contributions, and managed by Community Action Kentucky, Inc., and locally, its subcontractor, the Northern Kentucky Community Action Commission; and
- High Bill and Usage Alerts: Duke Energy Kentucky auto-enrolls all eligible non-AMI metered customers in our High Bill Alert program. These customers are notified when their bill is projected to be 30 percent and $30 higher than the previous month based on weather and 12 months of historical usage. Duke Energy transitions all eligible customers who receive an AMI-MDM certified meter from High Bill

Alerts to our Usage Alerts program, which uses interval data to calculate their electricity cost. These customers automatically receive an email at the midpoint of their billing cycle with their current electricity cost broken down by appliance and projected cost. Usage Alerts customers can also select a dollar amount to receive budget alerts. Eligible customers who start service at premises with an AMI-MDM certified meter are automatically enrolled in our Usage Alerts program.

In addition to programs specific to bill management, Duke Energy Kentucky offers a variety of options for customers relative to bill payment. Although customers can pay their bills using the United States Postal Service, they also have other options. The Company offers several convenient bill payment options, which include:

- Pay Online: The Pay Online function is a service for customers and provides access to make a one-time payment with a checking or savings account at no cost;
- Automatic Bank Draft: This program allows customers to have their monthly charges auto drafted from a checking or savings account at no cost;
- Card Payments via Speedpay: Customers may make a one-time, same-day payment online, via the mobile app, or by phone using a credit card, debit card, prepaid card, or electronic check (collectively, "card payments"), which applies the payment to the account immediately.

Currently, a transaction fee of $1.50 is charged to residential accounts. For non-residential accounts, an $8.50 fee per transaction up to $10,000 applies to each payment. For payments more than $10,000, the convenience fee is 2.75 percent of the amount paid. The charged third-party fees cover the processing cost associated with handling card payments; and

- Pay Agent Network: There are over fifty locations in the Duke Energy Kentucky service area where customers can make cash, check, or money order payments. These locations are found in establishments where customers typically conduct other business, such as grocery stores, pharmacies, convenience stores, and larger retailers.

C. CUSTOMER SATISFACTION

Q. HOW DOES DUKE ENERGY KENTUCKY MEASURE PERFORMANCE FOR PROVIDING HIGH QUALITY CUSTOMER SERVICE?

A. Duke Energy Kentucky recognizes that customer expectations continuously evolve and that it is critical for the Company to hear and understand the "Voice of the Customer" to improve overall customer satisfaction (CSAT). To that end, the Company operates a robust CSAT program that measures customer satisfaction performance through three primary tools: the Customer Experience Monitor (CX Monitor) survey; the annual J.D. Power Electric Utility Residential Customer Satisfaction Study (J.D. Power Study); and Duke Energy's proprietary transaction survey – Fastrack.

Q. PLEASE DESCRIBE THE CX MONITOR SURVEY AND DUKE ENERGY KENTUCKY'S PERFORMANCE IN THIS SURVEY.

A. In 2018, the Company launched the CX Monitor, a randomized, census-based survey that measures overall customer sentiment and the ongoing perceptions of the customer experience via an email invitation with an embedded online survey link. The CX Monitor survey is sent annually to all residential, small and medium business (SMB) customers, and large business customers for whom the Company has a valid email address. Customers are asked to provide feedback regarding their overall sentiment as well as satisfaction with key experiences they have had with the Company over the past 12 months. Examples of these experiences include billing and payment and power quality and reliability. Customers rate overall sentiment and key experience satisfaction on a '0-10' scale while also providing open-end verbatim comments detailing the primary reason(s) for their score. Scores are reported on a 'Net' basis – shown as the share of Promoters (customers providing a score of '9' or '10') minus the share of Detractors (customers providing a score of '0-6'). Since the CX Monitor survey launched in 2018, Duke Energy Kentucky alone has collected more than 36,000 residential electric customer surveys through December 2021. Duke Energy Kentucky measured an initial score of +15.5 in January 2018 and improved our NPS score to +41.2 in December 2021. This means that the Company has seen strong improvement in overall customer sentiment in the commonwealth.

Confidential Attachment ABS-1 is a copy of the Duke Energy Kentucky Electric Residential CX Monitor customer sentiment results from 2018 through 2021.

Q. PLEASE DESCRIBE THE J.D. POWER STUDIES AND DUKE ENERGY KENTUCKY'S PERFORMANCE UNDER THOSE STUDIES.

A. J.D. Power is a well-known measure of consumer opinion and customer satisfaction in many key industries. J.D. Power annually surveys electric utilities' residential customers regarding their overall satisfaction with their utility, as well as key areas of their relationship. Duke Energy Midwest (Kentucky and Ohio) participates in these annual utility studies.

The J.D. Power Study calculates overall customer satisfaction based on six performance areas: (1) power quality and reliability; (2) billing and payment; (3) price and value; (4) corporate citizenship; (5) communications; and (6) customer service. J.D. Power published the final results of its 2021 Customer Satisfaction Study on December 15, 2021.[2] While the utility industry and Midwest Large Region saw declining average scores in 2021, Duke Energy's Midwest (Ohio, Kentucky, Indiana) was up 2 points, and is now a second quartile performer within both the region and among all large utilities nationally. We are proud of the improvement in these scores and believe they reflect our commitment to improving our customers' experience across several key areas.

[2] The 2021 J.D. Power Electric Utility Residential Customer Satisfaction Study is comprised of four waves of interviews: 1) January/February 2021; 2) April/May 2021; 3) July/August 2021; and 4) October/November 2021.

Attachment ABS-2 is an excerpt from this recent publication that provides a relevant summary of residential customer satisfaction for Midwest utilities.

Q. PLEASE DESCRIBE FASTRACK AND THE COMPANY'S FASTRACK PERFORMANCE.

A. In addition to the independent J.D. Power Study, the Company uses "Fastrack," a proprietary, post-transaction CSAT measurement program. Fastrack measures customer satisfaction with recent interactions customers have had with the Company. Fastrack was intentionally designed to complement the CX Monitor survey and provide greater insight into experiences that matter to our customers and near real time feedback to our front line, customer-facing employees. The survey questions cover the customer's experience regarding completed field work, including requests to start and transfer electric service, restore outages, and repair outdoor lights. Analysis of these ratings helps to identify specific service strengths and opportunities that drive overall satisfaction and to provide guidance for the implementation of process and performance improvement efforts. In 2021 alone, Duke Energy Kentucky collected more than 2,000 Residential Fastrack surveys.

Duke Energy Kentucky's customer satisfaction scores indicate that, overall, customer satisfaction with these experiences is relatively high. Through all twelve months of 2021, customers provided the following ratings:

- **Start/Transfer Electric Service:** On average, 67 percent of Duke Energy Kentucky residential customers were Promoters – reporting high levels of satisfaction with their overall start/transfer service experience – with especially strong performance noted regarding the 'timeliness' of their connection;

- **Outage/Restoration:** On average, 66 percent of Duke Energy Kentucky residential customers were Promoters – reporting high levels of satisfaction with their overall outage experience. Still, some customers were Detractors, citing opportunities to improve the accuracy of estimated restoration times or to keep them better informed with key information points during their outage; and
- **Outdoor Lighting Repair:** With a Net Satisfaction score near 90 percent and an average share of Promoters topping 94 percent, Duke Energy Kentucky residential customers reported significantly high levels of satisfaction with their overall outdoor lighting repair experience. Customers were especially pleased with the timeliness of repairing their light(s), ease of completing their request, and the technician's performance respecting their property.

Confidential Attachment ABS-3 is a copy of the 2021 Duke Energy Kentucky Fastrack results by module.

D. DEVELOPMENTS SINCE THE COMPANY'S LAST ELECTRIC RATE CASE

Q. PLEASE SUMMARIZE THE SIGNIFICANT OPERATIONAL DEVELOPMENTS AND INVESTMENTS THAT HAVE OCCURRED SINCE THE COMPANY'S LAST ELECTRIC BASE RATE CASE.

A. Duke Energy Kentucky continues to make prudent operational decisions and investments in our electric generation and delivery system. Since the 2019 Rate

Case, Duke Energy Kentucky has invested $300 million in additional electric infrastructure to enhance the safety, reliability, and resiliency of our electric system and to support localized economic development through adequate infrastructure and capacity in areas where growth is occurring. Duke Energy Kentucky is experiencing significant development in specific areas of our service territory in Northern Kentucky where additional capacity and facilities are necessary to provide safe, reliable, and adequate service. Moreover, the Company continues to make necessary investments to our existing facilities to maintain reliability. Company witnesses Melillo and William Luke discuss this and other necessary infrastructure investments further in their testimonies.

Q. PLEASE DESCRIBE THE INVESTMENTS THE COMPANY IS MAKING TO FURTHER ENHANCE SERVICES FOR CUSTOMERS.

A. Looking forward, the Company is exploring strategies to improve the service we provide to customers and the overall performance of our electric delivery system. The Company continues to evaluate opportunities to make prudent investments in new technologies that provide value to our customers. Examples of such innovative technologies included in this proceeding, which I discuss later in my testimony, are a new Customer Information System (CIS), programs to support development of EV charging infrastructure, a new dynamic time of use rate for residential customers and a subscription-based solar development program for customers desiring to directly invest in renewable energy.

III. OVERVIEW OF DUKE ENERGY KENTUCKY'S RATE CASE

Q. PLEASE EXPLAIN WHY DUKE ENERGY KENTUCKY PROPOSES TO INCREASE ITS RETAIL ELECTRIC RATES.

A. The Company proposes new rates because our present base rates are no longer sufficient to enable the Company to furnish adequate, efficient, and reasonable service or have the opportunity to earn a fair rate of return on investments. Duke Energy Kentucky also needs to reflect the costs of service related to our capital investments and the operations and maintenance of our electric generation, transmission, and distribution systems that have occurred since our last rate case. Finally, to avoid inappropriate cost shifting, the Company's depreciation rates must be aligned with probable asset retirement dates. The Commission denied the Company's request to update its depreciation rates in the Company's last electric base rate proceeding. Because of that prior decision, the depreciation rates for the Company's East Bend Generating Station and Woodsdale Generating Station do not align with their end of service life, thereby creating substantial exposure for future customers to assume the costs for assets that are not used to serve them. The need to adjust depreciation rates is further evident in the fact that the East Bend station is projected to retire by 2035, earlier than what was contemplated in the Company's prior electric base rate case. This earlier retirement date is affected by developments occurring since the time of our last rate case, including, but not limited to, forecasted market prices, environmental regulations, and subsidies provided to low- and no-carbon emitting resources that have the effect of making fossil generation less economic. As more fully explained by other Company witnesses, Duke Energy Kentucky needs to properly align East Bend's and Woodsdale's depreciation rates with their anticipated service lives to avoid intergenerational subsidies and to protect and minimize the amount that future customers would pay for any post-retirement undepreciated plant remaining after the generating assets' retirement, as well as with their replacement resource(s).

Q. PLEASE GENERALLY DESCRIBE DUKE ENERGY KENTUCKY'S PROPOSED RATE INCREASE.

A. Duke Energy Kentucky proposes to increase our annual electric base rate revenues by approximately $75.2 million. The approximate $75.2 million increase to the current electric base rate revenue requirement and proposed, related rider adjustments represent an increase to total electric revenues of approximately 17.9 percent across all customer classes. This rate increase is necessary to allow Duke Energy Kentucky to recover our costs for providing reliable electric service and have the opportunity to earn a fair return on our shareholders' investment in electric generation and local transmission and distribution facilities.

Additionally, through this case, the Company is also proposing several enhancements for customers, including, but not limited to:

- EV development: Duke Energy Kentucky witness Cormack Gordon supports the Company's proposal for two new EV programs and supporting tariffs: 1) Electric Vehicle Site Make Ready Service (Rate MRC); and 2) Electric Vehicle Service Equipment (Rate EVSE); (collectively the EV Programs) to assist Duke Energy Kentucky's customers and the broader public in the transition to electric transportation infrastructure;

- Implementation of a new CIS: Duke Energy Kentucky has updated our existing CIS to a new, state of the art system as more fully explained by Duke Energy Kentucky witness, Retha Hunsicker. This software investment was placed fully in service in April 2022;
- Clean Energy Connection Tariff: In response to customers' desire to have access to renewable resources in the wholesale market to meet their corporate sustainability goals, the Company is proposing to implement a new subscription-based program. This tariff is designed for customers that wish to invest in a specific renewable energy resource and receive the "green attributes" from a specific renewable resource;
- Generating Asset True-Up Mechanism (Rider GTM), a placeholder rider to reconcile final recovery of any undepreciated plant related to the Company's generation portfolio (East Bend and Woodsdale) that may remain at the time of retirement; and
- Updates to the Company's Local Government Fee Tariff and a new Incremental Local Investment Charge (Rider ILIC) to recover the costs of incremental system investments required pursuant to a local ordinance or franchise, such as undergrounding of electric facilities or other relocations or system improvements and upgrades that are either

requested or required by local regulation that are outside the Company's regular system-wide construction plans.

Q. WHAT TEST PERIOD IS THE COMPANY USING IN THIS PROCEEDING?

A. Duke Energy Kentucky is using a forecasted test period that spans the twelve months beginning July 1, 2023 and ending June 30, 2024.

Q. PLEASE FURTHER DESCRIBE THE COMPANY'S PROPOSAL TO ALIGN THE DEPRECIATION OF EAST BEND AND WOODSDALE WITH THEIR SERVICE LIVES AND TO IMPLEMENT RIDER GTM.

A. In the Company's last electric base rate case, the service life of East Bend was assumed to include a retirement in 2041. As more fully explained by Company witnesses Sarah Lawler, William Luke, Scott Park, and Lisa Quilici, East Bend is facing numerous pressures that are impacting the service life of the asset. In short, it is becoming increasingly more expensive to own, operate, and maintain the plant in relation to market pressures such as competing fuels, environmental compliance, and federal legislative initiatives that are intended to encourage development of low- to no-carbon emitting resources that adversely impact the cost-effectiveness of other traditional resources such as coal. As a result of those factors, the Company's modeling shows that East Bend will likely retire in 2035. Consequently, the Company needs to align East Bend's depreciation rates to this service life to minimize future customers' exposure to the unrecovered net book value of the plant at the time of its retirement.

Because the Company was not permitted to update depreciation rates to include changes in plant balances between the Company's 2017 and 2019 electric rate cases, there will be a significant net plant balance not yet depreciated and therefore collected in rates by 2041. This must be corrected in this proceeding.

As explained by Mr. Luke, the Company will continue to perform necessary maintenance and make prudent investments to keep East Bend in service to the extent it remains economic to do so. However, as Mr. Park describes, current modeling shows that by 2035, the plant is projected to no longer be providing economic value to customers, at a point at which retirement is warranted. As a result, the Company needs to align depreciation expense with the asset's service life (now estimated to be 2035) to minimize any intergenerational cost subsidies. As more fully explained by Ms. Lawler, Rider GTM is merely the mechanism to true-up and recover any undepreciated plant that is not able to be recovered due to timing of incremental investments and base rate proceedings. The general construct of Rider GTM is supported by regulatory precedent.

In the last electric rate case, the retirement date of Woodsdale was assumed to be 2032, but the Company was also not allowed to update its depreciation rates for Woodsdale in that 2019 case. Mr. Luke discusses in his testimony how the Company is proposing to extend the useful life of this asset until 2040. This mitigates, in part, the depreciation expense impact of aligning East Bend's depreciation life with its service life.

Q. PLEASE FURTHER EXPLAIN THE COMPANY'S UPDATES TO ITS LOCAL GOVERNMENT FEE AND CREATION OF A NEW INCREMENTAL LOCAL INVESTMENT CHARGE.

A. As a general proposition and without regard to perpetual franchises, local cities control how Duke Energy Kentucky operates in the cities' respective borders through a franchise ordinance/agreement as well as other local ordinances. Franchises vary in term length, typically anywhere from a year to up to twenty years. These franchises typically define the conditions for the utility's use of the local right of way, and usually involve an assessment of a franchise fee from the utility, which by tariff and Commission precedent, is assessed on the bills of customers within that particular city. Additionally, the Company is subject to other ordinances that impact its operations through zoning, permitting, and construction.

In recent years, cities wishing to exert more control over the utility, encourage economic development, and provide enhanced benefits to their constituents are making more demands upon the Company through both franchise and other ordinances (*e.g.,* zoning, right-of-way, tree trimming) and permitting requirements. These terms and conditions often address the Company's location, relocation, and restrictions around our normal business operations and have resulted in more onerous conditions and demands being thrust upon Duke Energy Kentucky's operations through ordinance or incorporated in the franchise negotiations. While the Company remains willing and interested in working with our communities to make desired investments and continue providing safe, efficient, reasonable, and adequate service, it is undeniable that some of these conditions are imposing additional processes and significant costs upon the Company, and ultimately our customers, to achieve outcomes specific to just one community.

These additional processes and incremental costs that are specific to the municipality are outside of the utility's normal operations elsewhere and, in some instances, drive incremental investments outside of the Company's normal planning and how we must provide service in other areas of our service territory. In some instances, it may force the Company to divert to and spend budgeted capital in areas where we are obligated to spend instead of areas where spend is supported by system planning. As such, we are proposing edits to our government fee tariff, specifically include these incremental costs as well as the fees that these local franchises, ordinances, or other directives require.

The Company is also proposing a new surcharge mechanism, Rider ILIC, and a related process to ensure appropriate cost recovery from discrete customers if a city passes an ordinance that imposes such incremental costs upon the utility specific to that city, which are outside the normal system needs of the Company., As more fully explained by Company witness Bruce Sailers, the Company is proposing a process such that when the Company becomes obligated to make an investment or incur a specific cost at the direction of a city that is outside of the Company's normal operations or planning, the KPSC shall determine whether such a charge shall be included on all customer bills or only on those customers within the boundaries of the Public Authority imposing such costs.

Q. CAN YOU PLEASE PROVIDE AN EXAMPLE OF SUCH AN ORDINANCE OR FRANCHISE THAT WOULD IMPOSE SIGNIFICANT INCREMENTAL COSTS UPON THE COMPANY?

A. Absolutely. Copies of such an ordinance and a proposed franchise is attached as Attachments ABS-4 and ABS-5, respectively. Attachment ABS-4 is an ordinance that imposes additional processes on the Company for how it manages its pole attachments. Duke Energy Kentucky received the proposed franchise ordinance in ABS-5 from one of its larger cities that, if passed by this city, would require the Company, among other things, to: 1) completely underground our entire electric delivery system in that city within three years;[3] 2) relocate the Company's facilities at the Company's cost at the request of this city or any of its residents;[4] 3) require the Company to use union contractors or else get the city consent to use non-union contractors;[5] and 4) agree that all costs of complying with this city's

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[3] *See;* ABS-4; pg. 14; Section 16(d), providing in relevant part: "All existing above ground facilities shall be installed underground within three (3) years of any franchise granted pursuant to this Ordinance and shall be in conformance with the applicable requirements of this Ordinance and those set forth 15 in the Code, the Zoning Ordinance, or any other applicable federal state and local laws or regulations."

[4] *See;* ABS-4; pp. 15-16; Section 16(e)(2), The Government shall have the authority to order the relocation and/or for the Company to provide any required safety measures for any facility that due to proximity of a private property owner is interfering with the property owner's respective use of their property or is in violation of a safety standard set forth by law and/or regulation. Specifically, the Company agrees to either relocate and/or provide safety measures for a property owner whose ability to use, repair, rebuild, paint and/or make any required alterations to their property is impacted by the location of Company's facilities.

[5] *See;* ABS-4; pp. 19-20; Section 24: All subcontractors/contractors shall have employees which have the same level of skill and accountability as members of nationally recognized unions. Upon receipt of confirmation that all of the subcontractor/contractor's labor force is part of a nationally recognized union, additional information regarding the labor force shall not be required. In the event a subcontractor/contractor does not utilize workers from a nationally recognized union, a subcontractor/contractor shall provide additional information on all employees to insure proper level of skill and accountability. In addition, the Company shall also provide any permit, including all conditions, to its subcontractors/contractors and its subcontractors/contractors shall comply with the terms of said permit and conditions. It is the responsibility of the Company to ensure compliance with this Ordinance and all local, state and federal laws and regulations by its subcontractors/contractors.

ordinance should be borne by the Company.[6] While the Company is firmly committed to working with its communities to provide reasonable and adequate service and actively negotiates with cities in our territories that seek to implement valid franchises, Kentucky's statutory construct affords the Company few options to avoid arguably unreasonable franchise terms. Indeed, the options in reacting to an ordinance and related franchise include not bidding on the franchise, submitting or seeking protracted legal redress to challenge an ordinance. Moreover, with zoning or permitting ordinances that pose such onerous conditions, the Company's only recourse is to seek legal redress.

Notwithstanding the fact that the Company believes undergrounding of the entire electric delivery system within a city may be unreasonable, cost prohibitive, and at a minimum, impossible to accomplish within the time desired by the city, KRS 96.050 confers that right upon cities. The methodology of cost recovery, however, is left to the Commission. The Company is proposing a transparent tariffed process for cities wishing to regulate the Company's occupation of the city right of way that imposes additional costs upon the Company that are outside of normal operating expenses and system planning. If the city wishes to have such investments made within its borders, the Company will proceed to enable safe, reasonable, and adequate services consistent with the terms of a controlling

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[6] *See;* ABS-4; pg. 10; Section 9 A, providing in relevant part: "It is specifically agreed to and acknowledged by the Company that the "Franchise Fee" is a fee paid by Company's customers, based on percentage of their respective electric usage cost. *Company agrees and further acknowledges that costs associated with compliance with this Franchise, as well as any Ordinance, Regulation and/or permitting requirements, are separate and distinct for which Company's customers shall not be responsible*." *Emphasis added.*

ordinance, but that the costs will be borne by the cost causers; namely, the city or its constituents who will directly benefit therefrom.

The mechanism and process proposed by the Company is intended to allow the Company to recover our costs of complying with these ordinances, after having brought them to the Commission to determine how the costs of such ordinances should be addressed. Having this mechanism and process in place will assist the Company in negotiations going forward by making it clear that the cost recovery of these incremental locally-imposed costs will be determined by the Commission and may be recovered locally.

IV. INTRODUCTION OF WITNESSES

Q. PLEASE INTRODUCE THE OTHER WITNESSES IN THIS PROCEEDING.

A. I identify below the other individuals who will present testimony on behalf of Duke Energy Kentucky, as well as the subject matters of their respective testimony:

- Ron A. Adams, General Manager Transmission Vegetation, offers testimony on Duke Energy Kentucky's vegetation management practices;
- Christopher R. Bauer, Director, Corporate Finance, and Assistant Treasurer, discusses the Company's credit ratings, financial objectives, cash requirements, and capital structure;
- Grady "Tripp" S. Carpenter, Manager Financial Forecasting II, offers testimony supporting Duke Energy Kentucky's budgeting and

forecasting processes and sponsors certain forecast information used for the test period financial data;

- Jacob S. Colley, Director of Customer Services Strategy discusses the Company's current customer satisfaction initiatives to further improve the customers' experience;
- Huyen C. Dang, Director of Accounting, offers testimony on Duke Energy Kentucky's capital accounting processes and supports the actual net plant-in service included in proposed rate base and other actual plant-related information;
- Cormack C. Gordon, Director of Transportation Electrification discusses the Company's proposal for two new tariffs to support EV charging infrastructure;
- Paul L. Halstead, Director Jurisdictional Rate Administration; supports the Company's Clean Energy Connection proposal;
- Retha I. Hunsicker, Vice President Customer Connect-Solutions discusses the Company's efforts to create an enhanced CIS that is capable of delivering new and better flexibility for customers to control and manage their energy consumption;
- Jeffrey T. Kopp, Managing Director, 1898 & Company, supports the Company's generating portfolio decommissioning study;
- Sarah E. Lawler, Vice President, Rates and Regulatory Strategy OH/KY, provides a detailed overview of the filing;

- William C. Luke, Vice President Midwest Generation, discusses the Company’s generation portfolio;
- James J. McClay, Managing Director Natural Gas Trading, discusses the Company’s participation in the wholesale capacity market and the Company’s proposal for a new hedging plan;
- Max W. McClellan, Lead Load Forecasting Analyst, performed and supports the Company’s electric load forecast;
- Dominic “Nick” J. Melillo, Director, Asset Management, discusses the Company’s distribution and transmission system and how it provides safe, adequate, efficient, and reasonable service;
- Paul M. Normand, Principal with Management Applications Consulting, Inc., supports the Company’s Lead-Lag Study;
- Joshua C. Nowak, Assistant Vice President, Concentric Energy Advisors, offers testimony supporting Duke Energy Kentucky’s requested rate of return;
- John R. Panizza, Director, Tax Operations, addresses the Company’s tax expense in the test period revenue requirement;
- Scott Park, Managing Director IRP and Analytics, supports the analysis that support the retirement dates for the Company’s fossil generation portfolio;
- Lisa M. Quilici, Senior Vice President, Concentric Energy Advisors, discusses coal generating retirements;

- Bruce L. Sailers, Director Jurisdictional Rate Administration, offers testimony as to rate design and tariff language;
- Jeffrey R. Setser, Director of Allocations and Reporting, supports the Company’s various service agreements and associated allocations;
- John J. Spanos, Gannet Fleming Valuation and Rate Consultants, LLC, provides testimony on Duke Energy Kentucky’s latest depreciation study;
- Lisa D. Steinkuhl, Director Rates, and Regulatory Planning, provides testimony supporting Duke Energy Kentucky’s overall revenue requirement for the test period and certain adjustments to the test period financial data;
- Jacob J. Stewart, Director of Health and Wellness, supports the Company’s compensation and benefits programs;
- John D. Swez, Managing Director Power Trading and Dispatch, discusses the Company’s participation in the wholesale electric markets;
- Danielle L. Weatherston, Manager Accounting II, offers testimony regarding the Company’s accounting policies, the accounting treatment requested in this case, and supports other actual financial data included in this application; and
- James E. Ziolkowski, Director, Rates and Regulatory Planning, provides testimony regarding Duke Energy Kentucky’s cost of service study.

V. ATTACHMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE FR 7(1).

A. FR 7(1) requires the original and 10 copies of the Application to be filed plus a copy for anyone named as an interested party. Duke Energy Kentucky elected, and was approved for, the use of electronic filing procedures in this matter, in accordance with 801 KAR 5:001, Section 8. Furthermore, in a July 22, 2021, Order in Case No. 2020-00085, the Commission granted a "permanent deviation from the filing requirement in that section that requires a paper copy be filed with the Commission or other parties to that case." In accordance with the aforementioned rules and orders, Duke Energy Kentucky will retain the original filing in paper medium.

Q. PLEASE DESCRIBE FR 14(1) THROUGH FR 14(4).

A. These filing requirements provide for the Company to seek proposed new rates through a written Application addressing various matters, including the full name, address, and electronic mail address of the Company, and set forth the facts upon 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 the same. FR 14(2) applies to Duke Energy Kentucky because it is a corporation, registered to do business, and is in good standing in the Commonwealth of Kentucky. The Application submitted in this proceeding includes this information and was prepared at my direction. FR 14(3) and FR 14(4) are not applicable to Duke Energy Kentucky because it is neither a limited liability company nor a limited partnership.

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

A. FR 16(1)(b)(1) is a statement for the reason for the adjustment. As I explained above and as further explained by Ms. Lawler, the Company is proposing new electric base rates because the present rates reflect the cost of service from the Company's last base electric rate case filed in 2019 and depreciation rates filed in 2017, which are no longer sufficient to enable the Company to furnish adequate, efficient, and reasonable service at a fair, just, and reasonable rate. Duke Energy Kentucky also needs to reflect the costs of service related to capital investments and the operation and maintenance of our electric generation, transmission, and distribution systems that have occurred since the 2019 Rate Case.

Q. PLEASE DESCRIBE FR 16(1)(b)(2).

A. FR 16(1)(b)(2) is the certificate of assumed name. Duke Energy Kentucky's actual legal name is "Duke Energy Kentucky, Inc." The Company has filed for the assumed name of "Duke Energy." The certificate of assumed name is provided with our filing.

Q. PLEASE DESCRIBE FR 16(1)(b)(5).

A. FR 16(1)(b)(5) is a statement that customer notice has been given in accordance with the Commission's rules. The Company is publishing notice in accordance with the Commission's regulations.

Q. PLEASE DESCRIBE FR 16(2).

A. FR 16(2) is the notice of intent submitted to the Commission at least 30, but no more than 60, days prior to filing the Application. The notice was filed on November 1, 2022, at my direction.

Q. PLEASE DESCRIBE FR 16(3).

A. FR 16(3) states that notice given in accordance with 807 KAR 5:001 Section 17 will satisfy notice requirements of 807 KAR 5:051, Section 2. The Company provided notice to customers in accordance with 807 KAR 5:001 Section 17.

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

A. FR 16(7)(a) is a statement of attestation from me, 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 each program. The efficiency and productivity benefits that have resulted from these programs have occurred over time and thus are reflected in the Company's budgets included in the forecasted test period in this proceeding. These programs are described below:

- Service outage management systems: We manage electric outages using the following systems designed to enhance efficiency and productivity: Supervisory Control and Data Acquisition, the Distribution Outage Management System, and the Distribution Management System. Mr. Melillo describes our outage management process and systems in more detail.
- Electric distribution system maintenance programs: Our major programs to achieve efficiency and productivity in maintaining our distribution system are the substation inspection program, the line inspection program, the vegetation management program, the ground-line inspection and treatment program, underground cable replacement

program, the capacitor maintenance program, and dissolved gas analysis in substations program. These programs are all designed to keep our distribution systems in good working order through efficient use of our resources. These programs are part of our distribution maintenance practices, which Mr. Melillo discusses.

- Plant maintenance and pollution control improvements: Mr. Luke discusses various maintenance schedules and capital improvements, which have or will enhance the efficiency and productivity of the Plants

The cost savings impacts of these programs are reflected in the forecasted test period.

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

A. FR 16(7)(e) is a statement of attestation signed by me, the utility's chief officer in charge of Kentucky operations, that the forecast is reasonable, reliable, and made in good faith and all basic assumptions used in the forecast have been identified and justified and the forecast contains the same assumptions and methodologies as used in the forecast for use by management or an explanation for differences that exist, if applicable, and that productivity and efficiency gains are included.

Q. PLEASE DESCRIBE FR 17(1)

A. FR 17(1) relates to public postings. Duke Energy Kentucky will post a copy of the notice and Application at our place of business and will also make available on the Company's website a copy of the public notice and a hyperlink to the Commission's website where the case documents will be available.

Q. PLEASE DESCRIBE FR 17(2).

A. FR 17(2) is the customer notice.

Q. PLEASE DESCRIBE FR 17(3).

A. FR 17(3) includes the method of notice. Duke Energy Kentucky has published notice in newspapers of general circulation. Company witness Sailers supports FR 17(4), which describes required content of the notice. Duke Energy Kentucky has included all content listed in FR 17(4) in its notice.

Q. PLEASE DESCRIBE FR KRS 278.180.

A. FR KRS 278.180 is the pre-filing notice.

VI. CONCLUSION

Q. WERE FR 7(1), FR 14(1), FR 14(2), 14(3), 14(4), FR 16(1)(b)(1), FR 16(1)(b)(2), FR 16(1)(b)(5), FR 16(2), FR 16(3), FR 16(7)(a), FR 16(7)(e), FR 17(1), FR 17(2), FR 17(3), FR KRS 278.180, AND ATTACHMENTS ABS-1 THROUGH 5 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Amy B. Spiller, State President of Duke Energy Ohio, Inc. and its subsidiary, Duke Energy Kentucky, Inc., being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Amy B Spiller

Amy B. Spiller, Affiant

Subscribed and sworn to before me by Amy B. Spiller, on this 22ND day of NOVEMBER, 2022.

Adele M. Frisch

NOTARY PUBLIC

NOTARIAL SEAL STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

My Commission Expires: 1/5/2024

J.D. POWER

2021 Electric Utility Residential Customer Satisfaction Study

Topline Overview

December 15, 2021

2021 J.D. Power Electric Utility Residential Customer Satisfaction Study

PRESS RELEASE

Electric Utility Providers Can Increase Satisfaction by Supporting Local Economic Development Efforts, J.D. Power Finds

15 December 2021

Overall electric utility residential customer satisfaction is 748 (on a 1,000-point scale) in 2021, a decrease from a record-high 751 in 2020, according to the J.D. Power 2021 Electric Utility Residential Customer Satisfaction Study,SM released today. This year's study shows only 32% of customers are aware of their utilities' efforts to help economic development in their local communities.

"In today's roller coaster economic environment, electric utility providers need to not only increase their efforts to help their local economies but also communicate more effectively about utility programs and activities," said John Hazen, managing director of the utility practice at J.D. Power. "Utility customers want to hear about these efforts and, when they do, overall satisfaction is higher. Promoting economic development efforts can increase overall satisfaction by as much as 122 points."

Study Results

- **East Large** Segment: **PPL Electric Utilities** *(for a 10th consecutive year)*
- **Midwest Large** Segment: **Ameren Illinois**
- **South Large** Segment: **Florida Power & Light** *(for a second consecutive year)*
- **West Large** Segment: **SRP** *(for a 20th consecutive year)*

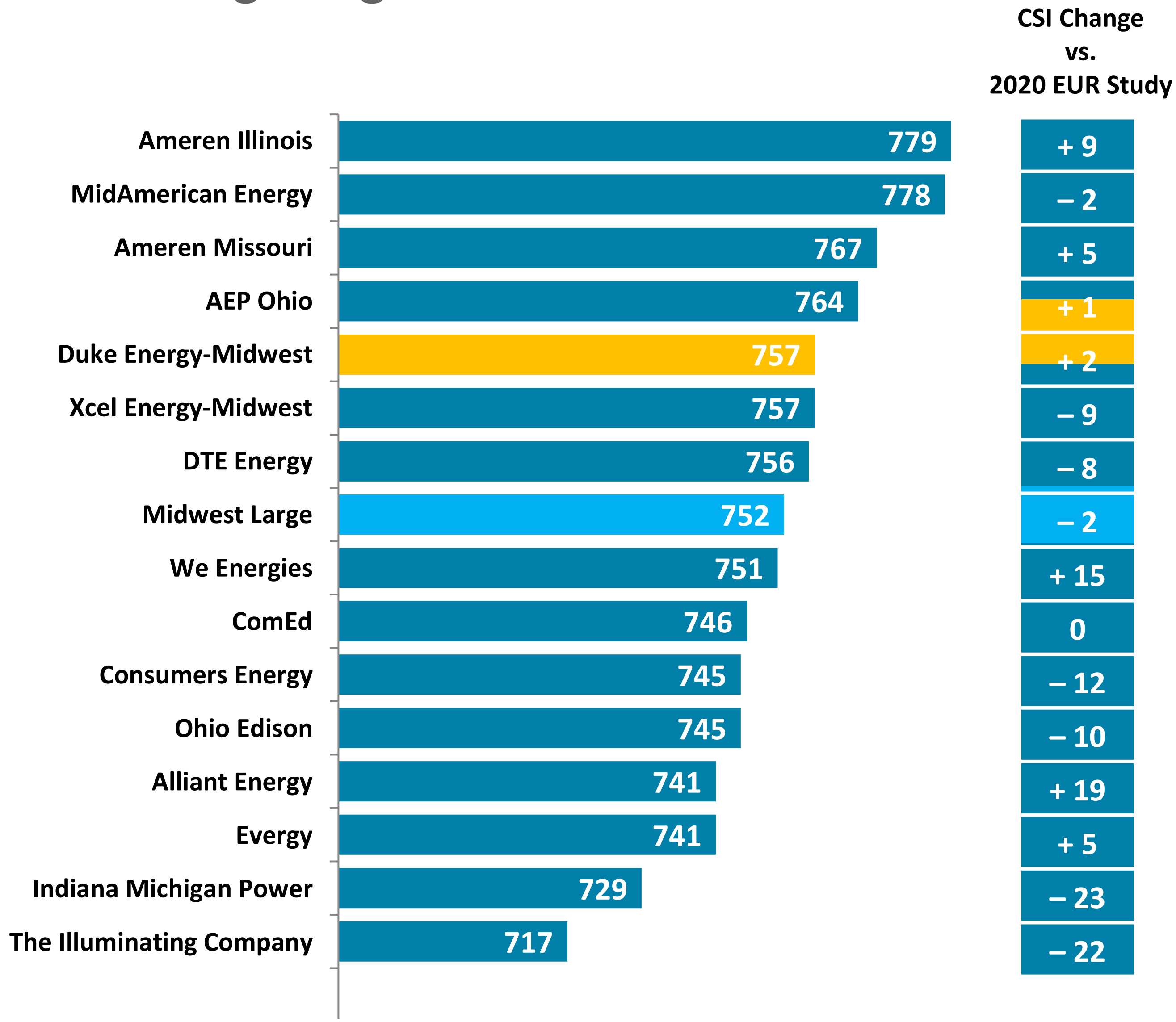
The 2021 Electric Utility Residential Customer Satisfaction Study is based on responses from 100,999 online interviews conducted from January 2021 through November 2021 among residential customers of the 145 largest electric utility brands across the United States, which represent more than 101 million households.

For more information about the Electric Utility Residential Customer Satisfaction Study, visit https://www.jdpower.com/business/resource/electric-utility-residential-customer-satisfaction-study

Midwest Large Region – Final Result

- While the industry and Midwest Large Region saw declining average scores in 2021, **DEMW was up 2 pts.,** and is now a **second quartile performer within both the region** and **among all large utilities nationally**.

2021 J.D. Power Electric Utility Residential Study CSI: Midwest Large Region



CITY OF COVINGTON

AGENDA ITEM REQUEST FORM

2022 AIR Submission Deadlines	
Dec 23	
Jan 7 & 21	July 1 & 22
Feb 4 & 18	Aug 5 & 26
Mar 4 & 25	Sept 9 & 23
Apr 8 & 22	Oct 7 & 21
May 7 & 27	Nov 10
June 10	Dec 2

Caucus Meeting Date	November 22, 2022
Legislative Meeting Date	November 29, 2022

Order ☐ Ordinance ☑ Resolution ☐ Presentation ☐

Division/Department	Div/Dept Head Signature	Responsible Staff Person
Legal	*David Davidson*	David Davidson

Specific Nature of Request

Adpotion of proposed Ordinance regarding use of utility poles in the right of way to require owner of the pole to inform the city of any leases of the pole and to provide for method of removing wires from poles when requested.

Description of Request Including Background Information if Relevant

There are utility poles in the City of Covington right of way and an agreement has been reached with Duke Energy to place those poles in the right of way and to use them to provide electrical power to the community. Duke Energy has leased those utility poles to third parties without notice to the City. When the City has sought to remove the poles and place utilities underground there has been an inability to do so because it is not known what entity has wires on the utility poles and how to contact them to remove the wires and have them placed underground. This proposed ordinance would require Duke Energy, or any entity using the right of way, to inform the city of the identity of any entity using the poles and it provides for a mechanism to ensure that those entities using the poles can be required to remove their wires frmo the poles.

Company/Entity (if multiple, list all)

Grant Funds Used - Yes: ○ No: ⦿
(list all grant fund types and the associated grant #, or check no)

Value/Cost

Funding Source Including Account No.

Payment Terms

Copy of Contract Attached?	Yes

SIGNING ORDER

David E. Davidson 11/10/22

1. LEGAL DEPARTMENT REPRESENTATIVE DATE

11/14/22

2. FINANCE DEPARTMENT REPRESENTATIVE DATE

11/16/2022

3. CITY MANAGER DATE

ADDITIONAL AIR FORM SUMBISSION INFORMATION:

Please attach all relevant documents, i.e., draft contracts, resumes, draft development agreements, etc.

For an Order authorizing an expenditure or obligation of funds, you MUST complete the following:

Value/Cost - The total amount of the expenditure or obligation

Funding Source - Source fund(s) including G/L account number(s) and amounts; if NOT budgeted type "not budgeted"

Payment Terms - The payment terms

If you do not have room to enter all required information, provide it in the Description of Request box with the designator "Funds Continued:"

For an Order approving a contract, you MUST attach a full, complete, unsigned copy of the contract, including ALL attachments and exhibits.

Contract draft and review requests must be submitted to the Legal Department at least one week prior to the AIR submission due date.

For the approval of a new or amended Ordinance, you MUST attach a full and complete copy of the property formatted Ordinance.

The Legal Department is available to help with ordinance drafting and review.

For an Order appointing a new employee, you MUST attach a copy of the resume.

For privacy, the resume will be provided directly to the BOC instead of being published in the meeting packets.

If the prospective employee is related to any current city employee, then you MUST prominently disclose this fact.

This information can be found under Rule 9 in the Board of Commissioners Rules of Procedure. (O-04-21)

COMMISSIONERS' ORDINANCE NO. ORD-xxx-22

AN ORDINANCE AMENDING SECTION 96.067 OF THE COVINGTON CODE OF ORDINANCES REQUIRING FRANCHISEES TO INFORM CITY OF LEASES OF UTILITY POLES AND TO REQUIRE FRANCHISEES TO REMOVE LESSEE'S EQUIPMENT FROM POLES WHEN DIRECTED

* * * *

WHEREAS, certain utility companies have operated in the City of Covington pursuant to franchise agreements with the City and those agreements include the right to keep and maintain utility poles in the public right of way;

WHEREAS, utility franchisees of the City have reached leases with certain companies for use of the franchisee's utility poles which exist in the public right of way;

WHEREAS, the utility franchisees with agreements with Lessees charge a fee to the Lessees and receive compensation from these sub-leases;

WHEREAS, the utility franchisees have not informed the City of the existence of Lessees, the identity of those Lessees, and contact or identification information of the Lessees;

WHEREAS, when utility franchisees have been directed to remove their equipment from utility poles and place them underground, the franchisees have claimed to be unable to direct removal of the equipment of their Lessees from the poles;

WHEREAS, Lessees using utility poles in the public right of way do so only with the permission of, and by paying a fee to, the franchisee;

WHEREAS, Lessees using utility poles in the public right of way have no direct relationship with the City even though their equipment is in the public right of way;

NOW THEREFORE,
BE IT ORDERED BY THE BOARD OF COMMISSIONERS OF THE CITY OF COVINGTON, KENTON COUNTY, KENTUCKY:

<u>Section 1</u>

Section 96.067 of the Covington Code of Ordinances is amended to read as follows:

§ 96.067 INSTALLATION, RELOCATION OR DISCONTINUATION OF FACILITIES.

(A) Provisions apply unless direct conflict exists. The provisions of this section shall apply unless they directly conflict with a tariff, state or federal law, or the provisions of the applicant's franchise agreement with the city. This section shall not be interpreted to impair the ability of a registrant to perform work not requiring a permit unless a public safety concern would arise if such work were to be performed.

(B) General application. Upon the written notice of and at the direction of the City Manager, a registrant shall relocate or remove facilities, or rearrange aerial facilities, if required by a tariff, state or federal law, a franchise agreement with the city or the provisions of this subchapter.

(C) Coordination. To the extent reasonably possible, registrants shall coordinate the installation, relocation and removal of their facilities with each other in order to avoid issues with respect to the location of facilities within the right-of-way.

(D) Procedure. The City Manager shall notify the applicant if the City Manager determines that a facility may not be installed as requested by the applicant. Upon determining that a facility may not be installed as requested, the City Manager shall provide written notice to the applicant as early as practicable and in conformity with any specific applicable notice requirement. The notice shall contain a description of the area affected as well as the reason for the City Manager's determination. The City Manager may issue a permit that is contingent upon certain condition(s) being fulfilled with respect to the criteria contained below.

(E) Reservation of rights. Notwithstanding any other provision in this subchapter, the city specifically reserves the right to order the removal or relocation of any facility installed after the effective date of this chapter, at no cost to the city for which the appropriate permit was not obtained.

(F) Preclusion on cutting newly paved surfaces.

(1) If any street is designated for resurfacing or reconstruction by the city on the list maintained pursuant to this subchapter, the registrant shall make any extensions, changes or installations of or to its facilities ahead of such activity. The registrant shall

notify the City Manager no less than 45 days prior to the city's anticipated bid date of its desire to perform such extensions, changes or installations, and may be allowed up to 90 additional days to complete the work.

(2) If any street is about to be constructed, reconstructed, widened, altered or paved by the city, the City Manager shall provide notice to registrants, and the registrant shall make any extensions, changes or installations of or to its facilities ahead of such activity. Depending on the amount of such extensions, changes or installations to be performed, the registrant may be allowed up to 120 days to complete the work, which the City Manager may extend for good cause. It is expected that the registrant shall not disturb the city's improvements within the following two-year period, so as to minimize the premature degradation of the right-of-way caused by multiple alterations and surface cuts. Upon a registrant's showing of undue hardship or emergency, the City Manager may grant permission for limited disturbance of the newly paved surface within the two-year period. The registrant shall in those instances comply with all other relevant provisions of this chapter pertaining to restoration of the right-of-way.

(G) Relocation.

(1) Generally. Upon providing reasonable advanced written notice to the registrant or other responsible party, the City Manager may order the relocation or rearrangement of any facility, in his or her reasonable discretion and in good faith, if any of the following arise with respect to that facility:

(a) The relocation or rearrangement is necessary for the purpose of public safety;

(b) The relocation or rearrangement is required by a tariff, state or federal law, or a franchise agreement with the city;

(c) The relocation or rearrangement is necessary to assist in the installation of facilities by another registrant or permittee;

(d) The relocation or rearrangement is necessary as a result of the city adopting a planned public project or policy requiring that facilities be relocated; and

(e) So as to conform to the established grade or line of a right-of-way or so as not to interfere with public improvements whenever the city shall grade, regrade, construct, reconstruct, widen or alter any right-of-way, or construct, reconstruct, repair, maintain or alter a public improvement, including, but not limited to, storm sewers, or street lights therein.

(2) Coordination. The city shall coordinate the new location with the registrant or permittee as part of the permitting process.

(3) Relocation underground. If, as a result of a planned public project, a registrant is required to relocate facilities that were previously and lawfully located above-ground, and the city requests, as part of the relocation, that the facilities be relocated to underground, the city may bear the cost for the difference in cost between an aerial and underground facility of the same type, unless an agreement to the contrary is otherwise entered into by the appropriate parties and unless applicable state law requires otherwise.

(4) Relocation for public safety reasons. If the basis for the city ordering the relocation of a facility is a public safety concern, the registrant shall relocate the facility at no cost to the city.

(5) Relocations to assist in the placement of other facilities. If a registrant is required to relocate facilities to assist in the installation of facilities by another registrant or permittee, the party seeking to install the facilities shall bear the costs of said relocation, unless an agreement to the contrary is otherwise entered into by the appropriate parties.

(6) Relocations where the cost is borne by the city. Notwithstanding any language in this subchapter to the contrary, unless an agreement to the contrary is otherwise entered into by the appropriate parties, the cost of the following types of relocations shall be borne by the city:

(a) The relocation is the result of the city adopting a plan or policy requiring that facilities be placed underground in that location, if, at the time the facility was installed, such a plan was not in place;

(b) The location in which the facility is currently sited was not a part of the right-of-way or was not otherwise owned or controlled by the city at the time the facility was installed;

(c) The city has previously ordered that the facility be relocated to comply with a public improvement project, the registrant or party has substantially complied with such order, and the city then orders the registrant or party to relocate that facility to a different area as part of the same project; or

(d) The city orders the relocation of a facility to accommodate a public improvement project, and the construction of such project is subsequently terminated by the city.

(H) ***Lessees***

(1) Any franchisee of the City of Covington that chooses to lease any utility pole to another entity, or which allows any other entity to use a utility pole in the public right of way, shall:

(a) Require in any agreement with a Lessee that it will remove its equipment from the utility pole when directed to do so by the City of Covington or by the franchisee;

(b) Require removal of the Lessee's equipment from the pole at the expense of the franchisee or the Lessee as the parties might agree;

(c) Require that the Lessee give identifying information to the City of Covington including its name, address for receiving regular U.S. Mail, e-mail address; telephone number of its office which responds to existence, installation, repair, maintenance, and removal of equipment which exists on utility poles in the public right of way;

(d) Require that the Lessee be duly authorized to do business in the Commonwealth of Kentucky and be subject to service of process in the Commonwealth;

(e) Require that the Lessee be duly authorized and licensed to do business in the City of Covington and that it pay and stay current on all license fees and occupational taxes in the City.

(2) The franchisee will contact and require its Lessees to remove their equipment from any utility pole in the public right of way when directed to do so by the City and/or the franchisee.

(3) Any refusal or failure of a franchisee to abide by the terms of the requirements of this ordinance will subject the franchisee to pay any and all expenses incurred by the City of Covington when any Lessee's equipment is removed from a utility pole in a public right of way. The expenses which the franchisee will be required to pay will include the attorneys fees and any costs incurred in defending any lawsuits brought by the Lessee for removal of the equipment and any

damages of any kind, including punitive damages, from removal of the equipment, including all damages and requited by § 96.065.

(4) Any franchisee that leases use of utility poles in the public right of way to other entities must keep record of any such entity, its identifying information (as described above) which pole or poles it is using, the amount it is paying the franchisee for use of the pole, and all other terms of the lease for use of the pole. These records must be made available upon request by the City.

[~~(H)~~] *(I)* Discontinuance of use.

(1) Any party discontinuing use of a facility shall notify the City Manager in writing of such discontinued use within 30 days. Said notice shall describe the facilities for which the use is to be discontinued and include a statement as to whether the registrant intends to leave the facilities in place for potential future use, remove the facilities or abandon the facilities in place. The registrant shall remain responsible for the maintenance, repair and condition of discontinued facilities at all times.

(2) The City Manager may order that the responsible party remove, replace or repair any discontinued facility which significantly interferes with the city's maintenance of the right-of-way.

(1984 Code, § 96.42) (Ord. O-04-20, passed 1-28-2020)

Section 2

That this order shall take effect and be in full force when passed and recorded according to law.

____
MAYOR

ATTEST:

____
CITY CLERK

Passed: ________________ (Second Reading)

________________ (First Reading)

ORDINANCE NO. _____

AN ORDINANCE CREATING AND ESTABLISHING FOR BID EXCLUSIVE ELECTRIC FRANCHISE FOR THE PLACEMENT OF FACILITIES FOR THE TRANSMISSION, DISTRIBUTION AND SALE OF ELECTRICITY WITHIN THE PUBLIC RIGHT-OF-WAY OF THE CITY OF COVINGTON FOR A TWENTY (20) YEAR DURATION, IMPOSING A FRANCHISE FEE IN OF THE SUM OF UP TO FIVE PERCENT (5%) OF FRANCHISEE'S GROSS RECEIPTS PER YEAR FROM THE FRANCHISEE'S SALE OF ELECTRICITY TO ELECTRIC-CONSUMING ENTITIES INSIDE THE CITY OF COVINGTON'S CORPORATE LIMITS AND FURTHER PROVIDING FOR INDEMNIFICATION; INSURANCE; CANCELLATION OR TERMINATION; AND BID REQUIREMENTS; ALL EFFECTIVE ON DATE OF PASSAGE.

WHEREAS, the Constitution of the Commonwealth of Kentucky, Sections 163 and 164, and Chapter 96 of the Kentucky Revised Statutes, authorize municipal corporations to require public utilities, including providers of electricity within their boundaries, to operate under franchise agreements and to grant utilities the right to use public right-of-way on such terms and conditions as are deemed reasonable and necessary; and further KRS 82.082 authorizes the City to exercise any and all powers within its boundaries that are not in conflict with the Kentucky Constitution or state statutes; and

WHEREAS, the City Commission of the City of Covington, Kentucky, has found and determined that the construction, operation, maintenance and utilization of an electric franchise over, across or under public right-of-way in the City of Covington, benefits said utility and the customers it serves and the City Commission has further found and determined that the construction, installation, removal, maintenance and/or repair of utility-owned facilities and other infrastructures does periodic and unavoidable disturbance that gradually results in the degradation of the City's streets and sidewalks, for which the City is entitled to reasonable compensation in order to offset and recover the costs of reconstructing, removing, repairing or resurfacing damaged public right-of-way; and,

WHEREAS, that the location of electric utility lines aboveground, has interfered with property owners use and enjoyment of property in the City of Covington, including, locating poles too close to buildings; and

WHEREAS, public necessity and convenience mandates locating of all electric utility lines underground for aesthetic, safety and development reasons; and

WHEREAS, grant of a Franchise for the use of Covington's rights of way and other public property is a revocable permit, subject to revocation at any time, *Spur Distributing Co., v. Husbands,* 124 S.W.2d 463 (Ky.1939); and

WHEREAS, in order to protect the health, safety and welfare of the citizens of Covington, Kentucky, to protect and preserve the City's public right-of-way and infrastructure and to provide for the orderly administration of the franchise contemplated herein, it is necessary and appropriate to require the successful franchisee to conduct its business and operations in a lawful manner in compliance with the terms and conditions set forth hereinbelow.

NOW, THEREFORE, BE IT ORDAINED BY THE CITY COMMISSION OF THE CITY OF COVINGTON:

SECTION 1

There is hereby created a non-exclusive franchise to enter upon, lay, acquire, construct, operate, maintain, install, use, and repair, in the Right-Of-Way of the City, a system or works for the transmission and distribution of electricity within and without the corporate boundaries of the City as it now exists or may hereafter be constructed or extended, subject to the provisions of this Ordinance. Such system may include poles, pipes, manholes, ducts, structures, and any other apparatus, equipment and facilities above and below the ground (collectively, "Equipment") necessary, essential, and/or used or useful to the transmission, distribution and sale of electricity through the City or to any other town or any portion of the county or to any other jurisdiction ("Services"). Additionally, the Company shall have the right to use the streets with its service and maintenance vehicles in furtherance of this Franchise. Prior to beginning the construction or installation of any new facilities under this Franchise, the Company shall obtain any necessary governmental permits for such construction or installation, copies of which it shall provide to the City. For avoidance of doubt, the Company shall not be required to obtain a permit prior to undertaking any maintenance or Emergency restoration work on existing facilities. To the extent a permit is necessary for such Emergency restoration work, the Company shall make any necessary permit application filings within, any prescribed time by applicable ordinance or if not provided by ordinance within a reasonable period, not to exceed fifteen (15) days, following completion of the work. Work performed by the Company under this Franchise shall be performed in a workmanlike manner and in such a way as not to unnecessarily interfere with the public's use of City streets. Whenever the surface of any City street is opened, it must be restored at the expense of the Company within any prescribed time by applicable ordinance of if not provided by ordinance, within thirty (30) days for hard surfaces and within fifteen (15) days for soft surfaces along city streets. Such restoration shall be to a condition comparable to what it was prior to the opening thereof. By way of example, brick pavers must be restored with brick pavers and stamped concrete must be restored with stamped concrete. During seasonal periods where weather prevents the restoration within the times set forth in this Ordinance or in the event of any shortage of materials or labor, the Company shall make temporary restorations satisfactory to the City and shall work with the City to develop a mutually agreeable and reasonable period for permanent restoration. In the event a street is opened at the request of the City for a reason other than providing adequate, efficient and reasonable service, then the City shall bear the expense of opening and restoring the street.

SECTION 2

The following definitions apply to this Ordinance:

City Commission means the legislative body of the City of Covington.

Company means the Party or Person that shall become the purchaser of said franchise, or any successor or assignee of such Party or Person.

Facility includes all property, means, and instrumentalities owned, operated, leased, licensed, used, furnished, or supplied for, by, or in connection with the business of the utility in the Right-Of-Way.

Government or *City* means the City of Covington.

Gross Receipts means those amounts of money which the Company receives from its customers within the City's geographical limits or boundaries for the retail sale of electricity under rates, temporary or permanent, authorized by the Kentucky Public Service Commission and represents amounts billed under such rates as adjusted for refunds, the net write-off of uncollectible accounts, corrections or other regulatory adjustments. Revenues do not include miscellaneous service charges, including but not limited to turn-ons, meter sets, insufficient funds, taxes, local fees, late fees and interest, which are related to but are not a part of the actual retail sale of electricity.

Party or *Person* means any natural or corporate person, business association or other business entity including, but not limited to, a partnership, a sole proprietorship, a political subdivision, a public or private agency of any kind, a Utility, a successor or assign of any of the foregoing, or any other legal entity. As used in this ordinance, the term *Parties* shall collectively refer to the Company and the Government.

Public Utility or Utility means a Party or Person that is defined in KRS Chapter 278.010 as a utility and: (i) is subject to the jurisdiction of the Kentucky Public Service Commission or the

Federal Energy Regulatory Commission; or (ii) is required to obtain a franchise from the Government to use and occupy the Right-Of-Way pursuant to Sections 163 and 164 of the Kentucky Constitution.

Right-Of-Way means the surface of and the space above and below a public roadway, highway, street, freeway, lane, path, sidewalk, alley, court, boulevard, avenue, parkway, cartway, bicycle lane or path, public sidewalk, or easement held by the Government for the purpose of public travel and shall include Rights-Of-Way as shall be now held or hereafter held by the Government.

SECTION 3

The Franchise created herein shall be non-exclusive and shall continue for a period of TWENTY (20) years from and after the effective date of this Ordinance, as set forth in Section 5. The Company may, at its option, terminate this Franchise upon one hundred eighty (180) days' written notice if: (a) the City breaches any of its obligations hereunder and such breach is not cured within ninety (90) days of the Company's notice to the City of such breach; (b) the Company is not permitted to pass through to affected customers all fees payable by it under Section 9 herein; or (c) the City creates or amends any ordinance or regulation which, in the Company's sole discretion, would have the effect of: (i) substantially altering, amending or adding to the terms of this Ordinance; (ii) substantially impairing the Company's ability to perform its obligations under the Franchise in an efficient, unencumbered and profitable way; or (iii) preventing the Company from complying with applicable statutes or regulations, rules or orders issued by the Kentucky Public Service Commission. Without diminishing the Company's rights under this Section 3, the City agrees that to the extent it desires to pass or amend an ordinance or regulation which could have the effect of substantially: (i) altering, amending, or adding to the terms of this Ordinance; (ii) impairing the Company's ability to perform its obligations under this Franchise in an efficient, unencumbered and profitable way; or (iii) preventing the Company from complying with applicable statutes or regulations, rules or orders issued by the Kentucky Public Service Commission, that it will first discuss such proposed ordinance or regulation with the Company and the parties shall negotiate in good faith regarding the same.

SECTION 4

The Company is authorized to operate throughout all the territory within the corporate limits of the City for which it is authorized under state or federal law.

SECTION 5

This Ordinance shall become effective on the date of its passage and publication as required by law. The Franchise created by this Ordinance shall take effect no earlier than thirty (30) days after the City Commission accepts the bid(s).

SECTION 6

The Company shall comply with all provisions of the City's Code of Ordinances ("Code"), including but not limited to, Urban Forestry, Right of Way Encroachment, Historic Guideline, and Streetscape Design Standards and City regulations (including any amendments thereto), unless such provisions: (i) conflict with the Company's ability to comply with any rule, regulation or order issued by the Kentucky Public Service Commission related to the Company's rates or services; or (ii) are otherwise preempted by the action of any state or federal authority with jurisdiction over the Company. The Company shall not be excused from complying with any of the terms and conditions of this Ordinance by any failure of the Government, upon any one or more occasions, to insist upon the Company's performance or to seek the Company's compliance with any one or more of such terms or conditions.

SECTION 7

Rights Reserved by City. Subject to the above provisions, the Franchise created by this Ordinance is expressly subject to the right of the City: (i) to repeal the same for misuse, nonuse, or the Company's failure to comply with applicable local, state or federal laws; (ii) to impose such other regulations as may be determined by the City to be conducive to the safety, welfare and morals of the public; and/or (iii) to control and regulate the use of its Right-Of-Way as permitted by law. All rights and privileges granted in any electric franchise shall be subject to the provisions hereof, this Ordinance and to all powers (including police power) inherent in, conferred upon, or reserved to the City, including but not limited to those contained in the Code and in all regulations and or policies promulgated by the City.

SECTION 8

As consideration for the granting of the Franchise created by this Ordinance, the Company agrees it shall defend, indemnify, and hold harmless the Government from and against claims, suits, causes of action, proceedings, judgments for damages or equitable relief, and costs and expenses asserted against the Government that the Company's use of the Right-Of-Way or the presence or operation of the Company's equipment on or along said Right-Of-Way has caused damage to tangible property or bodily injury, if and to the extent such damage or injury is not caused by the Government's negligence, gross negligence or willful conduct. The Government shall notify the Company in writing within a reasonable time of receiving notice of any issue it determines may require indemnification

SECTION 9

A. Franchise Fees. For the privilege of utilizing said public streets and rights of ways, the Company, its successors and assigns, shall be required to pay to the Government monthly three percent (3%) of Gross Receipts per month from the Company's sale of electricity to electric-consuming entities (which includes businesses, industrial facilities and dwellings) inside the City's corporate limits. Additionally, the City reserves the right to increase the franchise fee at any time after the one-year anniversary of the effective date of this Ordinance, and upon prior ninety (90) days written notice to the Company. Should the City exercise said right to increase the franchise fee, the City shall receive payment of franchise fees in an amount not to exceed five percent (5%) of the Gross Receipts received by the Company from the Company's sale of electricity to electricity-consuming entities (which includes businesses, industrial facilities and dwellings) inside the City's corporate limits.

Unless otherwise agreed in writing, no acceptance of any franchise fee payment by the Government shall be construed as an accord and satisfaction that the amount paid is in fact the correct amount nor shall acceptance be deemed a release to any claim the Government may have for future or additional sums pursuant to this Franchise. Any additional and non-disputed amount due to the Government shall be paid within ten (10) days following written notice to the Company by the Government.

The Government shall have the right to inspect the Company's electric income records no more than once, annually, related to the Company's electric gross receipts within the City for a time period consisting of the lesser of the effective date of the franchise or the most recent two years (the Audit Period). The Government shall retain the right to audit and to re-compute any amounts determined to be payable under this agreement for the Audit Period; provided, however, that such audit shall take place within twelve (12) months following the close of the Company's fiscal year. If, as a result of such audit or review, the Government determines that Company has underpaid its franchise fees to the Government in any twelve (12) month period by ten percent (10%) or more, then, in addition to making full payment of the relevant obligation, the Company shall reimburse the Government for all expenses incurred as a result of an audit or review and such payments shall be paid within the thirty (30) days following written notice to the Company by the

Government, which notice shall include a copy of the audit report and copies of all invoices for which the Government seeks reimbursement. If the audit shows that the Company has overpaid its franchise fee in any twelve (12) month period, then the Government will promptly make a payment to the Company of the overpayment amount and Company will make appropriate bill adjustments to affected customer's bill to credit back the overpayment.

Once the Government has exercised its right to audit any fiscal year, such year shall not be includable within the scope of any subsequent audit by the Government unless agreed to by the Company.

If any franchise fee is owed to the Government, in the event that any franchise fee payment or recomputed amount is not made to the Government on or before the applicable dates heretofore specified, interest shall be charged from such date at the annual rate of 2% over prime interest rate, unless the Company demonstrates that the non-payment is the result of an act or omission of the Commonwealth of Kentucky or the City and wholly beyond the fault of the Company.

Any other fees assessed to the Company in connection with the Company's operation within the City pursuant to this franchise, including use of the City's public ways, including fees associated with permits and licenses of whatever nature, shall be payable by the Company only if and to the extent such fee is provided for under the laws of the Commonwealth of Kentucky and to the extent the Company is authorized by the Kentucky Public Service Commission (or its successor) to pass through such fees to the entities served by it inside the City's corporate limits.

To the extent the Company actually incurs other reasonable incremental costs in connection with its compliance with the Code, the Government agrees that the Company may recover such amounts from its customers pursuant to the terms of a tariff filed with and approved by the Kentucky Public Service Commission, if otherwise permitted by law.

It is specifically agreed to and acknowledged by the Company that the "Franchise Fee" is a fee paid by Company's customers, based on percentage of their respective electric usage cost. Company agrees and further acknowledges that costs associated with compliance with this Franchise, as well as any Ordinance, Regulation and/or permitting requirements, are separate and distinct for which Company's customers shall not be responsible.

B. Attorney's Fees: Notwithstanding the above, the Company shall be required to pay the City an amount intended to adequately compensate it for its permitting and inspection of the Company's construction activities in the Rights-of-way pursuant to the Code and all attorney's fees that the City may incur relating to the franchising process, including but not limited to any attorneys' fees incurred relating to the drafting of this Ordinance, the granting of the franchise and any transfer, renewal or modification of the franchise.

SECTION 10

The Company shall maintain in force through the term of the Franchise insurance coverage for general liability insurance, auto liability and workers compensation, in accordance with all applicable laws and regulations. The Company shall maintain a general liability and auto liability coverage minimum limit of $2,000,000 per occurrence. The Company may elect to self-insure all or part of this requirement.

SECTION 11

The Company agrees to charge such rate or rates as may from time to time be fixed by the Kentucky Public Service Commission or any successor regulatory body and will give notice of same as required by KRS 278.180 and the Orders of the Kentucky Public Service Commission construing same.

SECTION 12

In the event the Government believes the Company has materially breached this franchise or violated one of its terms, the Government shall provide written notice to the Company that states the precise alleged breach or violation and shall provide the Company a reasonable opportunity, not to exceed thirty (30) days from receipt of notice, to provide evidence that such breach or violation has not occurred or to take action to cure such breach or violation.

If after thirty days, the Company has either failed to provide evidence of such breach or violation not occurring or has failed to commence action to cure such breach or violation, the City reserves the right to assess a penalty in the amount of $500 per violation or breach.

If payment of any penalty assessed under this provision not made to the Government on or before the applicable dates specified, interest shall be charged from such date at the annual rate of 2% over prime interest rate, unless the Company demonstrates that the non-payment is the result of an act or omission of the Commonwealth or the City and beyond the fault of the Company.

The Parties retain all rights available under the law of the Commonwealth of Kentucky with respect to enforce provisions of this Ordinance or any contract derived from the passage of this Ordinance, including the right to seek remedies at law, and direct damages.

The payment of penalties or damages shall not excuse non-performance under this Ordinance. The right of the Parties to seek and collect damages as set forth in this section is in addition to its right to terminate and cancel as set forth in Section 13 of this Ordinance.

In no event shall either Party be liable under this Agreement to the other Party any special, incidental, punitive, exemplary or consequential damages.

<u>SECTION 13</u>

(a) In addition to all other rights and powers pertaining to the Parties by virtue of the Franchise created by this Ordinance or otherwise, the Government, by and through its City

Commission, and the Company, each reserve the right to terminate and cancel this Franchise and all rights and privileges of the hereunder in the event that the other Party:

(1) Willfully violates any material provision of this Franchise, except where such violation is without fault or through excusable neglect;

(2) Willfully attempts to evade any material provision of this Franchise or practices any fraud or deceit upon the other Party;

(3) Knowingly makes a material misrepresentation of any fact in the application, proposal for renewal, or negotiation of this Franchise; or

(4) Is no longer able to provide regular and customary uninterrupted service to its customers in the franchise area.

(b) Prior to attempting to terminate or cancel this Franchise pursuant to this section, the City's Mayor or his or her designee, or the City Commission, or the Company shall make a written demand that the Company or City do, or comply with, any such provision, rule, order or determination. If the violation, found in Section 13(a), by the Company or the City continues for a period of thirty (30) days following such written demand without written proof that corrective action has been taken or is being actively and expeditiously pursued, the Government may place its request for termination of this Franchise as early as the next regular City Commission meeting agenda. The Government shall cause to be served upon the Company, at least ten (10) days prior to the date of such City Commission meeting, a written notice of intent to request such termination and the time and place of the meeting, legal notice of which shall be published in accordance with any applicable laws. In the event of a breach by the City, the Company retains all rights available under the law of the Commonwealth of Kentucky with respect to enforce provisions of this Ordinance or any contract derived from the passage of this Ordinance, including the right to seek remedies at law, and direct damages or termination of the contract or franchise.

(c) Any violation by the Company or its successor or the City of the material provisions of this Franchise, or the failure promptly to perform any of the provisions thereof, shall be cause for the forfeiture of this Franchise and all rights hereunder if, after written notice to the Company or City and a reasonable opportunity to cure, such violations, failure or default continue as set forth in Section 13(a).

SECTION 14

Right to Cancel. The City shall have the right to terminate the Franchise created by this Ordinance thirty (30) days after the appointment of a receiver or trustee to take over and conduct the business of the Company, whether in receivership, reorganization, bankruptcy or other action or proceeding, unless such receivership or trusteeship shall have been vacated prior to the expiration of said thirty (30) days, unless:

1. Within thirty (30) days after his election of appointment, such receiver or trustee shall have fully complied with all the provisions of this Ordinance and remedied all defaults thereunder; and,
2. Such receiver or trustee, within said thirty (30) days shall have executed an agreement, duly approved by the court having jurisdiction in the premises, whereby such receiver or trustee assumes and agrees to be bound by each and every provision of this Ordinance and the Franchise granted to the Company.

SECTION 15

In the event of a change of Kentucky law whereby retail rates of electric customers are no longer regulated by the Public Service Commission, the Government shall have the option of terminating this Franchise with the Company. If this Franchise is terminated by the Government pursuant to this provision, the Government and the Company shall have a duty to negotiate in good faith with respect to offering a mutually acceptable franchise to the Company.

SECTION 16

The Company shall conform to at least the minimum standards or requirements in federal and state law or regulation in the operation of its electric system pursuant to this Ordinance. In addition to complying with other applicable law, the Company agrees that:

(a) All materials and equipment used or installed in construction shall be of first class quality, and any defect in the work, materials or equipment, whether latent or patent, will be remedied by the Company at its cost;

(b) Construction, reconstruction, maintenance, or removal of any facilities, shall be performed with due regard for the rights of the Government and others, and shall not unnecessarily interfere with, or in any way injure the property of the Government or others under, on, or above the ground, or otherwise unduly interfere with the public use of the rights-of-way;

(c) Placement of lights, danger signals or warning signs shall be undertaken by the Company in compliance with applicable law; and

(d) All new facilities shall be installed and shall be in conformance with the applicable requirements of this Ordinance and those set forth in the Code, the Zoning Ordinance, or any other applicable federal state and local laws or regulations. All existing above ground facilities shall be installed underground within three (3) years of any franchise granted pursuant to this Ordinance and shall be in conformance with the applicable requirements of this Ordinance and those set forth in the Code, the Zoning Ordinance, or any other applicable federal state and local laws or regulations. The Company assumes all responsibility for damage or injury resulting from its placement or maintenance of any facilities.

(e) The Government shall have the ability to order the relocation of any facility located within the rights-of-way.

1. Whenever the Government shall grade, regrade, construct, reconstruct, widen or alter any right-of-way or shall construct, reconstruct, repair, maintain or alter a public improvement, including, but not limited to, storm sewers, sanitary sewers and street lights therein, it shall be the duty of the Company, when so ordered by the Government, to change, relay and relocate its facilities in the right-of-way at no cost to the Government so as to conform to the established grade or line of such right-of-way and so as not to interfere with such public improvements so constructed, reconstructed or altered. However, notwithstanding the above, if as part of said public improvement the Government, receives grant money, as part of a state for federally funded project, applicable for the relocation of any above-ground, to be relocated underground, the grant or other award shall be applied with the Company to bear any additional cost. The Company specifically acknowledges and agrees that the placement of facilities in the City's right of way is a revocable permit, which may be revoked for specific facilities for the reasons set forth herein.
2. The Government shall have the authority to order the relocation and/or for the Company to provide any required safety measures for any facility that due to proximity of a private property owner is interfering with the property owner's

respective use of their property or is in violation of a safety standard set forth by law and/or regulation. Specifically, the Company agrees to either relocate and/or provide safety measures for an property owner whose ability to use, repair, rebuild, paint and/or make any required alterations to their property is impacted by the location of Company's facilities.

3. If the reason the Government is ordering the relocation is to assist in the installation of facilities by another party, the party seeking to install the facilities, or the project funding source, shall bear the costs of said relocation, unless an agreement is otherwise reached. This shall not apply to any relocation resulting from the relocation required by redevelopment and/or construction of a City owned property, which shall include ownership by Industrial Revenue Bond and/or similar economic incentive issued pursuant to applicable state law.
4. The Company shall, at no cost to the Government, place facilities underground if said above-ground facilities cause a public safety concern or are required to be placed underground pursuant to federal, state or local laws or regulations.

SECTION 17

This Ordinance and any Franchise awarded pursuant to it shall be governed by the laws of the Commonwealth of Kentucky, both as to interpretation and performance. The venue for any litigation related to this Ordinance and any Franchise awarded pursuant to it shall be in a court of competent jurisdiction in Kenton County, Kentucky.

SECTION 18

This Ordinance and any Franchise awarded pursuant to it does not create a contractual relationship with or right of action in favor of a third party against either the Government or the Company.

SECTION 19

If any section, sentence, clause or phrase of this Ordinance is held unconstitutional or otherwise invalid, such infirmity shall not affect the validity of the remaining Ordinance unless the rights of the City or Company are materially altered or impaired.

SECTION 20

It shall be the duty of the City Commission, through the City Manager's Office, to offer for sale at public auction the Franchise and privileges created hereunder. Said Franchise and privileges shall be sold to the highest and best bidder or bidders at a time and place fixed by the City Commission after given due notice thereof by publication or advertisement as required by law. In awarding the franchise, the City shall consider the technical, managerial, and financial qualifications of the bidder to perform its obligations under the franchise.

SECTION 21

Bids and proposals for the purchase and acquisition of the franchise and privileges hereby created shall be in writing and shall be delivered to the City Commission, through the office of the City Manager, upon the date(s) and at the times(s) fixed by publication(s) or advertisement(s) for receiving same. Thereafter, the City Manager shall report and submit to the City Commission, at the time of its next regular meeting or as soon as practicable thereafter, said bids and proposals for its approval. The City Commission reserves the right, for and on behalf of the Government, to reject any and all bids for said franchise and privileges; and, in case the bids reported by the City Manager shall be rejected by the City Commission, it may direct, by resolution or ordinance, said franchise and privileges to be again offered for sale, from time to time, until a satisfactory bid therefore shall be received and approved.

As further consideration for the granting of this Franchise, the Company agrees to pay all publication costs and attorneys' fees, the City incurs in the granting of this Franchise. The above-mentioned costs shall be invoiced by the City to the Company and the Company shall pay said costs within thirty (30) days of receipt of said invoice.

In addition, any bid submitted by a corporation or person not already owning within the territorial limits of the City a plant, equipment, and/or Facilities sufficient to render the service required by this Ordinance must be accompanied by cash or a certified check drawn on a bank of the Commonwealth of Kentucky, or a national bank, equal to five percent (5%) of the fair estimated cost of the system required to render the service, which check or cash shall be forfeited to the Government in case the bid should be accepted and the bidder should fail, for thirty (30) days after the confirmation of the sale, to pay the price and to give a good and sufficient bond in a sum equal to one-fourth (1/4) of the fair estimated cost of the system to be erected, conditioned that it shall be enforceable in case the purchaser should fail, within sixty (60) days, to establish and begin rendering the service in the manner set forth in this Ordinance. Such deposit need not be made by a corporation or person already owning within the territorial limits of the City a plant, equipment, and/or Facilities sufficient to render the service required by this Ordinance.

SECTION 22

The Franchise shall not be assignable without the written consent of the City; however, Franchisee may assign the Franchise to any affiliate, parent, or subsidiary entity which may, during the Term of the Franchise, assume the obligation to provide electricity throughout and for consumption within or outside the City without being required to seek the City's consent to such assignment. The Company shall provide the City with any notices required under the law of the Commonwealth of Kentucky.

If the Company experiences a foreclosure or other judicial sale of all or a substantial part of the Company's Facilities located with the City of Covington, the Company shall provide the Government with any notices required under the law of the Commonwealth of Kentucky.

SECTION 23

If the Company has sublet, leased or allowed other co-location on any facilities, (hereinafter "subtenant"), the Company shall solely be responsible for any required movement of their subtenant's equipment pursuant to relocation or other action as set forth in this Ordinance. In addition to, the Company shall indemnify and hold harmless the City from any and all claims, demands or others that result from subtenant's use of Company's facilities.

SECTION 24

As a result of past issues regarding non-Company employees work on Company's facilities in the City, including but not limited to, failure to comply with applicable ordinances and/or regulations, the following performance standards must be met. If the Company utilizes contractor(s) and/or subcontractor(s) for construction, installation, removal, maintenance and/or repair of Company-owned facilities within the jurisdictional boundaries of the City, consent from the City must be obtained, ensuring knowledge and compliance with applicable City ordinances and/or regulations. In addition to, subcontractors/contractors must provide cost details and period of contract (start to finish date). A list of subcontractors/contractors working in the City of the previous calendar year must be provided to City staff in January of the preceding year. The Company's subcontractors/contractors must provide to the City proof of automobile, general liability and worker's compensation insurance and proof of a City occupational license fee number. Lastly, proof of any required gross receipts and applicable tax paid thereon.

All work performed by the Company's subcontractors/contractors shall be approved by the City, prior to commencement of work. All subcontractors/contractors shall have employees which have the same level of skill and accountability as members of nationally recognized unions. Upon receipt of confirmation that the all of the subcontractor/contractor's labor force is part of a nationally recognized union, additional information regarding the labor force shall not be required.

In the event a subcontractor/contractor does not utilize workers from a nationally recognized union, a subcontractor/contractor shall provide additional information on all employees to insure proper level of skill and accountability. In addition, the Company shall also provide any permit, including all conditions, to its subcontractors/contractors and its subcontractors/contractors shall comply with the terms of said permit and conditions. It is the responsibility of the Company to ensure compliance with this Ordinance and all local, state and federal laws and regulations by its subcontractors/contractors.

SECTION 25

As set forth herein, the "Franchise Fee," is a fee paid by the Company's customers. In as much, Company agrees as further consideration of the use of the City's rights of way, the Company agrees to apply all Revenue Justification Policies, Economic Development Policies and/or other similar policy or procedure, provided for in the submittals to the Kentucky Public Services Commission by the Company. The Company agrees that the "urban" nature of the City, when redevelopment occurs, shall be considered and receive identical incentives as set forth above, a new construction in the more suburban parts of Kenton County and Company's Northern Kentucky Service Area.

SECTION 26

This Ordinance shall be in full force and effect from and after its reading, adoption and publication.

APPROVED:

____

ATTEST: Mayor

____

City Clerk

1st Reading: ___________________________

Adoption: ___________________________

Publication: ___________________________

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

RON A. ADAMS

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

December 1, 2022

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Ron A. Adams, and my business address is 6188 Mt. Gallant Road, York, South Carolina.

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

A. I am employed by Duke Energy Carolinas, LLC as General Manager, Transmission Vegetation Management Strategy. Duke Energy Carolinas, LLC is an affiliate of Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I received a Bachelor of Science degree from Clemson University in Electrical Engineering in May 1985. I am a registered professional engineer in the States of North and South Carolina and a Senior Member of the Institute of Electrical and Electronics Engineers (IEEE). I joined Duke Energy in 1985 as a Substation Engineer. In 1996, I was promoted to Manager, Technical Services within Transmission. Since that time, I have held positions of increasing responsibility in various departments including, engineering, construction and maintenance, field operations, and corporate governance with a passion for customer service and operational excellence. In 2016, I moved from my role as Director, Vegetation Management Governance to General Manager of Transmission Vegetation Management. In 2020, I moved to my current position as General Manager, Transmission Vegetation Management (VM) Strategy.

Q. PLEASE DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS GENERAL MANAGER, TRANSMISSION VEGETATION MANAGEMENT STRATEGY.

A. As General Manager of Transmission Vegetation Management Strategy, my responsibilities include the design and implementation of utility Transmission Vegetation Management (TVM) standards, programs and specifications to provide safe and reliable service in all the states in which Duke Energy provides electric services. I am responsible for coordinating the development and oversight of the annual program budget and as well as coordination and management of the work management system to support the field execution activities. Our Strategy team works with the regional teams to develop and prioritize the annual work plans to ensure safe and reliable service as well as Transmission grid security and resiliency within our service territories. In addition, I communicate with state, regional and federal authorities regarding Duke Energy's TVM policies and practices as well as work with our distribution vegetation management team on joint strategic initiatives.

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

A. I will describe Duke Energy Kentucky's current distribution and transmission vegetation management program, which focuses on both maintaining our existing rights-of-way and identification of hazard and danger trees and associated removal outside of our rights-of-way. I also will discuss the Company's update to the vegetation management program that incorporates a threat and condition-based approach to our Integrated Vegetation Management (IVM) strategy for Transmission. This approach currently leverages LiDAR (Light Detection and Ranging) technology to identify vegetation threats that are targeted for removal along transmission lines.

II. DUKE ENERGY KENTUCKY'S CURRENT VEGETATION MANAGEMENT PROGRAM

Q. PLEASE PROVIDE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S VEGETATION MANAGEMENT PROGRAM GOALS.

A. Duke Energy Kentucky's electric service territory covers five counties in northern Kentucky. Duke Energy Kentucky supplies electric service to approximately 149,200 residential, commercial and industrial customers. Duke Energy Kentucky's vegetation management goal is to balance the need for safe and reliable utility service with safe and cost-effective vegetation management practices.

The Duke Energy Kentucky Vegetation Management Program is based on an Integrated Vegetation Management (IVM) strategy, with the primary objective being to control the growth of incompatible vegetation along its electric lines to help provide safe and reliable service to our customers. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation control practices to reduce, manage or eliminate incompatible growth.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

Q. PLEASE EXPLAIN THE COMPANY'S IVM STRATEGY TOWARDS VEGETATION MANAGEMENT?

A. The Company's IVM strategy applies to both Transmission and Distribution and focuses on delivering safe and reliable electric service in a cost-effective manner while utilizing industry best management practices for vegetation management. Duke Energy Kentucky takes a proactive approach to its vegetation management program, which means we utilize qualified contract vegetation management companies to prune or cut down trees and other vegetation that may cause problems before service is affected. Duke Energy Kentucky's primary focus is to control the growth of incompatible vegetation along its electric lines by monitoring the condition of vegetation over, under, and adjacent to our electric facilities.

As part of the IVM strategy and in addition to our planned routine work, the Company also utilizes various vegetation control practices to reduce, manage or eliminate incompatible growth, such as the use of herbicides and mowing. Vegetation along electrical delivery lines, if not properly maintained, can create serious risks to reliability as well as potential safety concerns. Duke Energy Kentucky knows that a strong vegetation management program is a key component to meet system reliability.

Q. PLEASE PROVIDE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S DISTRIBUTION VEGETATION MANAGEMENT (VM) PROGRAM

A. Duke Energy Kentucky's Distribution VM program is based on maintaining and clearing all the Company's distribution circuits every five years. Consistent with the Kentucky Public Service Commission's Order in Case No. 2006-00494, the Company developed a distribution vegetation management plan that is on file with the Commission. The current full-system maintenance inspection and work cycle covers 1,441 miles of distribution overhead lines to be maintained. A five-year work cycle is approximately 288 miles per year. A copy of the current Distribution VM plan is included as Attachment RAA-1 to my testimony which reflects recent formatting changes and edits to provide greater specificity and definition to the plan.

The Company's vegetation management plan includes a description of the Company's tree care standards and pruning specifications that include minimum clearances, brush and wood removal and customer notifications. The Company provides the Commission with an annual report of its vegetation management plan in accordance with the Commission's Order in Case No. 2011-00450.[1] The last report was filed on or about May 2, 2022.

Duke Energy Kentucky works consistently to balance aesthetics with our goal to provide safe, reliable power to the households and businesses that depend on us. It is our responsibility to ensure power lines are free of trees and other

[1] *In the Matter of An Investigation of the Reliability Measures of Kentucky's Jurisdictional Electric Distribution Utilities,* Case No. 2011-00450. (Ky. P.S.C. May 30, 2013).

obstructions that could disrupt electric service. Trees that are close to power lines must be pruned or cut down to ensure they do not cause power outages, and Duke Energy Kentucky does much of this work proactively. The necessary crews use a variety of methods to manage vegetation growth along both distribution and transmission rights of way, including vegetation pruning, felling (cutting down) and herbicides. These methods are based on widely accepted standards developed by the tree care industry. All work is performed in conformance with Duke Energy Kentucky's vegetation management requirements, OSHA regulations, American National Standards Institute (ANSI) A300, ANSI Z133, Tree Care Industry Association's (formerly the National Arborist Association) standards, Dr. Shigo's *Field Guide for Qualified Line Clearance Tree Workers*, National Electrical Safety Code (NESC), International Society of Arboriculture Best Management Practices, and all federal, state, county, and municipal laws, statutes, ordinances and regulations applicable to said work.

Q. AS PART OF ITS ROUTINE 5-YEAR WORK CYCLE FOR THE DISTRIBUTION VEGETATION MANAGEMENT PROGRAM, DESCRIBE THE RELIABILITY, SAFETY, AND OTHER CRITERIA USED IN DETERMINING WHETHER TREES AND VEGETATION REQUIRE WORK.

A. Duke Energy Kentucky's Distribution VM program uses data analytics to prioritize annual vegetation management plans. This analysis considers age since previous pruning, customer satisfaction data, and vegetation related outages since the previous pruning. The Company uses foresters who are certified by the

International Society of Arboriculture (ISA) to provide guidance and oversight to contractors who are pruning trees and clearing brush growth around, over and under power lines. In addition to the routine work cycle, we perform periodic visual inspections to determine whether the Company's targeted 10 feet of clearance along the distribution lines is maintained or requires additional attention in advance of the schedule. During routine vegetation maintenance, our employees and contractors are also identifying hazard trees that pose a risk and remove the affected trees once permissions are received. Our Hazard Tree Removal Program is another component of our IVM strategy for the Distribution VM program.

Q. DESCRIBE HOW THE HAZARD TREE REMOVAL PROGRAM SUPPORTS SYSTEM RELIABILITY AND STORM HARDENING?

A. To maintain safety and reliability, Duke Energy Kentucky is engaged in a Hazard Tree Removal Program that is designed to remove trees that pose a potential danger to our distribution system. This program seeks to remove living and dead trees outside of the Company's right-of-way that pose a risk to our distribution system, including ash trees, to counter the effects of the Emerald Ash Borer infestation.

There are two components to the Hazard Tree Program. First, when our contractors are performing routine work, they are instructed to look outside the ten-foot clearance zone. If they identify trees that are infested with the Emerald Ash Borer or otherwise are a threat to our distribution lines, we will work with our customers to remove the tree.

The second component of this initiative occurs outside the normal work cycle. The Company has retained "Hazard Tree Identifiers" or contractor foresters who conduct visual inspections and identify hazard trees in our service territory. Our contractor will then work with our customers to obtain permission to remove these trees before they have a chance to damage our system.

Over the past five years, approximately 45% of the total distribution vegetation related outages, including Major Event Days (MEDs), in Kentucky were due to trees falling into the distribution lines from outside the right of way. Overall, vegetation related outages account for approximately 20% of all distribution outages in Kentucky. Because of this, Duke Energy Kentucky has and will continue its program to remove hazard trees that are likely to cause a problem with Duke Energy Kentucky's distribution system from outside the Company's right of way to drive reliability and storm resiliency.

Q. PLEASE PROVIDE AN OVERVIEW OF DUKE ENERGY KENTUCKY'S TRANSMISSION VEGETATION MANAGEMENT (TRANSMISSION VM) PROGRAM.

A. The Duke Energy's Kentucky Transmission VM program follows an IVM strategy along with associated industry standards just like the Distribution VM program that targets removal or control of incompatible vegetation to minimize potential outages to the transmission system and ensure necessary access within all transmission line corridors. The reason for the transmission IVM strategy is to create, promote, and conserve sustainable plant communities that are compatible with the intended use of the site, and manage incompatible plants that may conflict with the safe and reliable operation of the transmission system. This approach is recognized as an industry best management practice and is in alignment with ANSI A300 Part 7 standard. The objective of this IVM approach is to maintain the transmission rights of way such that compatible, low growing woody-shrub species and herbaceous grasses can exist in the rights of way corridor. The program focuses on the removal and/or control of incompatible vegetation within or along the corridor to minimize the risk of vegetation related outages, maintain adequate clearances and ensure necessary access within all transmission line corridors.

Q. PLEASE DESCRIBE THE ANNUAL WORK STREAMS IN THE TRANSMISSION VM PROGRAM.

A. The Transmission VM program includes the following annual activities:

- Planned Corridor Work;
- Reactive Work including hazard tree mitigation; and
- and Floor Management (herbicide, mowing, and hand cutting).

The Transmission program focuses on a threat and condition-based maintenance approach using technology, including remote sensing (currently LiDAR) to monitor and address vegetation conditions across all jurisdictions.

Q. WHAT DO YOU MEAN BY A THREAT AND CONDITION-BASED MAINTENANCE APPROACH TO TRANSMISSION VEGETATION MANAGEMENT?

A. At a high level there are typically three types of maintenance strategies, Time-based, Condition-based and Predictive based maintenance. Time-based maintenance is what has been historically utilized in the industry. This involves a period or cycle-based vegetation management strategy that is over a period of years. It is not based upon analytical data, just a goal of performing vegetation management for a defined number of circuits or miles a year, over a period of years.

But with the advancement in technology and computer processing, the industry is transitioning to a condition-based strategy. This condition-based approach leverages technology and analytics to identify potential incompatible vegetation threats and determine where, when and how much vegetation work is needed. If you have good data and information, then you can utilize a condition-based maintenance strategy. Currently, transmission leverages remote sensing data to identify threats as either a grow-in, fall-in or blowing-together threat to our transmission lines.

Potentially in the future by leveraging more advanced technology such as artificial intelligence and granular information, utilities may be able to utilize a "predictive-based" maintenance strategy that will more precisely predict future vegetation threats that could impact system safety or reliability.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY COMPATIBLE AND INCOMPATIBLE VEGETATION.

A. Duke Energy Kentucky utilizes a process to define compatible and incompatible vegetation to balance the needs of public and worker safety as well as the reliable operation of the transmission system. A time-based herbicide program is used to further manage the ROW of incompatible vegetation and support the IVM strategy.

Compatible vegetation is vegetation within the Transmission Right of Way that *will not* mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will not limit or block access, or the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

Conversely, incompatible vegetation is vegetation within or outside the Transmission Right of Way that will mature to a height or size that *will* pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will limit or block access, or the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

Q. PLEASE EXPLAIN THE TRIGGERS USED TO DETERMINE INCOMPATIBLE VEGETATION?

A. For planned work, threat trigger distances are part of the remote sensing program to identify potential vegetation threats that do not allow for safe or reliable operation of the transmission facilities, under all operating conditions (designed blowout and designed maximum operating sag). These threat triggers are radial distances based on engineering design criteria for the conductor sag and blowout operating locations and are voltage dependent.

These threat trigger distances are voltage specific and provide for approximately 6 years of typical vegetation re-growth, while supporting minimum safe worker distances. Once vegetation has been identified as a potential threat, the vegetation will be confirmed and evaluated in the field by qualified Company representatives to determine a mitigation strategy through the work planning process.

Q. PLEASE EXPLAIN THE WORK PLANNING PROCESS USED BY DUKE ENERGY KENTUCKY TO MITIGATE VEGETATION RISKS TO THE TRANSMISSION SYSTEM.

A. During the work planning and marking process, many factors and criteria are considered when developing the mitigation strategy. A Duke Energy Kentucky utility vegetation management professional will evaluate the vegetation based on arboricultural, regulatory/safety standards, legal ROW rights and criteria such as size, age, location, growth rate, maintained/landscaped areas of property versus non-maintained/non-landscaped areas. All incompatible vegetation will be identified during these evaluations and will be targeted for removal.

To better understand how Duke Energy Kentucky leverages the threat and condition-based approach, I explain how it ties into annual program activities:

- Planned work is prioritized and scheduled using remote sensing, annual aerial patrol and field assessment data while considering other factors such as the date of previous work and outage history;
- Reactive work is identified and prioritized through the remote sensing, annual aerial inspections, and on-going field inspections; and
- Floor Management is focused on managing incompatible vegetation in the floor of the corridor and is a time-based program.

Q. PLEASE FURTHER EXPLAIN THE PLANNED AND REACTIVE WORKSTREAMS YOU PREVIOUSLY MENTIONED.

A. The Planned and Reactive work activities noted above include identifying outside-of-right of way fall-in threats for evaluation and mitigation. These targeted activities include cutting down healthy trees that pose a threat to the transmission system where the Company has legal rights as well as cutting down diseased, dying or defective hazard trees like infested ash trees to drive reliability and storm resiliency. Since 2017, 100% of the sustained vegetation-related transmission outages for Duke Energy Kentucky have been caused by trees falling into the transmission lines from outside the right of way.

III. DUKE ENERGY KENTUCKY'S VEGETATION MANAGEMENT PROGRAM GOING FORWARD

Q. PLEASE SUMMARIZE DUKE ENERGY KENTUCKY'S APPROACH TO VEGETATION MANAGEMENT FOR 2023 -2024.

A. Duke Energy Kentucky will continue to implement the IVM program strategy as previously described for both Transmission and Distribution. For the Distribution VM program, the Company will continue to operate under its approved five-year routine work cycle as well as execute the Hazard Tree Removal Program. Additionally, the Transmission VM program will continue to implement its threat- and condition-based approach for its transmission system which includes Planned, Reactive and Floor Management work activities. The continued focus by both Distribution and Transmission on removals will help ensure reliability and support storm hardening of the Duke Energy Kentucky electric system.

IV. CONCLUSION

Q. DO YOU BELIEVE THAT DUKE ENERGY KENTUCKY VEGETATION MANAGEMENT PROGRAM AS OUTLINED IN YOUR TESTIMONY WILL ALLOW THE COMPANY TO CONTINUE TO PROVIDE SAFE AND RELIABLE SERVICE?

A. Yes.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

STATE OF S.C)
) **SS:**
COUNTY OF York)

The undersigned, Ron Adams, GM Transmission Vegetation, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Ron Adams Affiant

Subscribed and sworn to before me by Ron Adams on this 18th day of Nov., 2022.

CATHY LYNN HUDSON
COMM. EXP.
NOTARY PUBLIC
03-02-2032
SOUTH CAROLINA

Cathy Lynn Hudson
NOTARY PUBLIC

My Commission Expires: 03-02-2032

Vegetation Management Program – Duke Energy Kentucky, Inc

Distribution Vegetation Management Program – Duke Energy Kentucky, , Inc

SECTION 1- GOAL, OBJECTIVES, AND PURPOSE

Duke Energy Kentucky's vegetation management goal is to balance the need for safe and reliable utility service with safe and cost-effective vegetation management practices.

The primary objective of the Duke Energy Kentucky Vegetation Management Program is to control the growth of incompatible vegetation along its electric lines to help provide safe and reliable service to our customers. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation control practices to reduce, manage or eliminate incompatible growth. This integrated vegetation management program is essential in providing safe and reliable electric service by ensuring that trees and brush near or within rights-of-way are periodically trimmed or removed to help reduce potential outages and hazards near our facilities.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

SECTION 2 – DEFINITIONS

ANSI A300 - American National Standards Institute (ANSI) A300 for Tree Care Operations provides the generally accepted industry performance standards for the care and management of trees, shrubs, and other woody plants.

ANSI Z133 - American National Standards Institute (ANSI) Z133 for Arboricultural Operations provides the generally accepted industry safety standards for the care and management of trees, shrubs, and other woody plants.

ASSET PROTECTION - Duke Energy department that enforces transmission right of way legal rights.

BRUSH - A perennial woody stem less than six inches DBH (diameter at breast height).

CIRCUIT MILES - (for reference and reporting purposes) The distance, in miles, of primary voltage electric lines from the substation to the end of the circuit including single phase, two phase or three phase configurations. The distance is measured to the nearest 1/10th of a mile.

COMPATIBLE VEGETATION – Vegetation within the distribution right of way that does not present a grow-in or fall-in threat that has a typical mature height of less than 15 feet and whose trunk is typically no closer than 20 feet from the center of the right of way.

CONTRACTOR - Corporation to whom the vegetation management work is awarded.

DANGER TREE – A tree that if it were to fall or be cut would be tall enough to strike electrical lines and equipment of the distribution system.

HAZARD TREE - A tree that is dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment of the distribution system if it falls or is cut.

INCOMPATIBLE VEGETATION – Vegetation within or outside the distribution right of way that will mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the distribution conductor, or that will limit or block access to distribution facilities during routine or emergency maintenance activity.

INTEGRATED VEGETATION MANAGEMENT - Vegetation plan that combines various components including pruning, mowing, removals, and herbicide applications to manage the growth of vegetation on the electric utility rights-of-way.

LEGAL- Duke Energy Legal Department.

MAINTAINED/LANDSCAPED AREAS - An area where cut brush typically cannot be left on-site. Maintained areas typically include maintained yards and landscaped areas.

NON-MAINTAINED/NON-LANDSCAPED AREAS - An area where cut brush can be left on-site. Non-Maintained areas are unimproved areas or natural areas.

OPEN WIRE SECONDARY (OWS): A distribution line configuration that uses 2, 3 or 4 un-insulated conductors stacked vertically with 12 inches spacing between conductors, used to deliver secondary voltages ranging from 120- 600 volts to the customer.

SECTION 2 – DEFINITIONS CONTINUED

PRIMARY LINE: Electric conductor(s) energized at greater than 600 volts of electricity.

RIGHT-OF-WAY (ROW)- A strip of land that an electric utility uses to construct, operate, inspect, maintain, repair, or replace an overhead or underground power line. The ROW allows the utility to provide clearance from trees, buildings and other structures that could interfere with the line installation, maintenance, and operation. ROW may include licenses, easements and other rights to access property.

SECONDARY LINE: Electric conductor(s) are energized at 600 volts or less of electricity.

SERVICE – TRIPLEX – MULTIPLEX CABLE: Electric conductor(s) energized at 600 volts or less of electricity and terminate at a service delivery point. A bundle of three or four conductors, most commonly used to provide aerial service to homes and businesses, denoted by its 3 or 4 polyethylene coated conductors wrapped around a bare, aluminum conductor.

SINGLE PHASE PRIMARY: A type of electric power line construction that contains one (1) conductor energized at primary voltage.

THREE PHASE PRIMARY: A type of electric power line construction that contains three (3) conductors energized at primary voltage.

TREE- A perennial woody stem equal or greater than six inches in DBH (diameter at breast height)

TWO PHASE OR OPEN WYE: A type of electric power line construction that contains two (2) conductors energized at primary voltage.

UNIT MILE: A mile within a circuit that is required to be or has been trimmed per contract specifications.

SECTION 3 – FEDERAL, STATE, AND LOCAL LAWS

Contractor shall perform all work in conformance with Duke Energy Kentucky Vegetation Management Program requirements and work specifications, Occupational Health and Safety Administration (OSHA) regulations, American National Standards Institute (ANSI) A300 and Z133, and all federal, state, county, and municipal laws, ordinances, and regulations applicable to said work.

The governing entities include but are not limited to:

- Kentucky Public Services Commission (Commission)
- Kentucky Transportation Cabinet (Department of Transportation)
- Kentucky Department of Agriculture
- Occupational Health and Safety Administration (OSHA)
- American National Standards Institute (ANSI)
- Easement and/or Permit Documents

SECTION 4 – PROPERTY ACCESS RIGHTS / REQUIREMENTS

The rights to access, inspect, or perform the work associated with vegetation management practices include, but are not limited to, established legal instruments, easements, public road rights-of-way, municipal ordinances, state statutes, regulatory rules, tariffs, and other legal authority. Personnel responsible for implementing vegetation management on behalf of Duke Energy Kentucky should, when necessary, utilize the available supporting documents to pursue the completion of necessary work activities to maintain vegetation growth to the established standards of acceptance in the provision of safe and reliable electric service. If there are objections, restrictions or limitations that prevent completion of the necessary work activities, personnel should contact the Land Services Department or Legal Department for specialized assistance.

A list of items to determine property access rights include, but are not limited to:

- Existing property easement, prescriptive easements, public road rights of way and / or agreements
- State statutes
- Municipal codes
- Commission rules, regulations, orders, and approved tariffs.

SECTION 5 – WORK QUALITY AND SAFETY STANDARDS

All work shall be performed in conformance with the governing rules from the following: Duke Energy Kentucky Vegetation Management Program Requirements, OSHA regulations, National Electrical Safety Code (NESC) and all federal, state, county, and municipal laws, statutes, ordinances, and regulations applicable to said work.

Clearance to obtain safety and reliable electric service are based on, but not limited to, consideration of the following:

NESC

ANSI A300 Standard - American National Standards Institute A300 for Tree Care Operations
For utility line clearance work, the primary foci are Parts 1, 7 and 9.

ANSI Z133 Standard - American National Standards Institute Z133 for Tree Care Operations - Safety Requirements

OSHA Standard 29 Code of Federal Regulations (CFR) 1910.269 - OSHA Standard 29 CFR 1910.269 (a)(1)(i)(E) for Electric Power Generation, Transmission, and Distribution

Pruning Trees Near Electrical Utility Lines – A Field Pocket Guide for Qualified Line-Clearance Tree Workers by Dr. Alex L. Shigo

SECTION 6 –DISTRIBUTION VEGETATION MANAGEMENT OVERVIEW FOR PLANNED WORK

Based on a data driven approach and to facilitate a 5-year trim cycle, Duke Energy Kentucky will review, and clear vegetation as needed from approximately 20% of distribution system miles annually. Vegetation maintenance may include tree pruning, mechanical trimming, brush cutting/mastication, herbicide application and tree removal. The primary objective of the Duke Energy Kentucky Vegetation Management Program is to control the growth of incompatible vegetation and remove hazard trees along its electric lines to help provide safe and reliable service to our customers by limiting or eliminating the possibility of contact by vegetation which has grown towards or could fall into the overhead distribution lines. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation control practices to reduce, manage or eliminate incompatible growth.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

Distribution Line Clearances

Trees located along the right-of-way edge will, in most cases, encroach upon the electrical conductors through the side growth of their limbs. The maintenance of these trees requires the removal or partial removal of those potentially interfering limbs. Industry standards dictate the proper methods of "pruning" such limbs to minimize any damages to the tree. Incompatible brush within the distribution right-of-way corridors is eliminated if possible. When such vegetation is eliminated, it will normally be cut down either by manual or mechanical means.

- Primary distribution lines are typically cleared during routine pruning to obtain no less than ten feet of side clearance. Unsuitable branches which are dead, dying, diseased or structurally unsound and above distribution facilities are removed during pruning.
- Secondary, including open wire secondary distribution conductors (without a primary distribution line and excluding a service drop), are trimmed on an as needed basis.
- Multiplex cables and guy wires (without a primary distribution line and excluding a service drop), are trimmed on an as needed basis. Removal of load bearing limbs that are in contact with conductors and have a size and weight that causes tension on the conductor or interference with the normal sag or alignment of the conductor will be pruned for a minimum of 12 inches of clearance.
- Duke Energy Kentucky shall have no responsibility to clear vegetation from a service drop.

Hazard Tree Mitigation

Trees found within or adjacent to the right-of way that are dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment are targeted to be taken down. Stumps from trees (live) taken down shall be treated with herbicides where appropriate and possible.

SECTION 7 – INSPECTIONS AND MONITORING

Duke Energy Kentucky can and may perform inspections on distribution circuits to observe vegetation conditions on the distribution system. These inspections should provide for the capabilities to specifically identify potentially incompatible vegetation conditions. The intent of these inspections is to identify off-cycle vegetation threats along the distribution line corridors and take appropriate action.

Transmission Vegetation Management Program – Duke Energy Kentucky, Inc.

CONTENTS

SECTION 1 – GOALS, OBJECTIVES AND PURPOSE

The goal of Duke Energy Kentucky's vegetation management goal group is to balance the need for safe and reliable utility service with safe and cost-effective vegetation management practices.

The primary objective of the Duke Energy Kentucky Vegetation Management Program is to control the growth of incompatible vegetation along its electric lines to help provide safe and reliable service to our customers. This is accomplished by using qualified personnel to monitor the condition of the utility rights-of-way and by initiating various vegetation control practices to reduce, manage or eliminate incompatible growth. This integrated vegetation management program is essential in providing safe and reliable electric service by ensuring that trees and brush near or within rights-of-way are periodically trimmed or removed to help reduce potential outages and hazards near our facilities.

The consistent implementation of industry accepted vegetation management practices reduces the likelihood of tree and power line conflicts, as well as service interruptions, and allows for the full utilization of the operating system.

SECTION 2 – DEFINITIONS

ANSI A300 - American National Standards Institute (ANSI) A300 for Tree Care Operations, provides the generally accepted industry performance standards for the care and management of trees, shrubs, and other woody plants.

ANSI Z133 - American National Standards Institute (ANSI) Z133 for Arboricultural Operations, provides the generally accepted industry safety standards for the care and management of trees, shrubs, and other woody plants.

ASSET PROTECTION - Duke Energy department that enforces transmission right of way legal rights.

BRUSH - A perennial woody stem less than six inches DBH (diameter at breast height).

COMPATIBLE VEGETATION – Vegetation within the Transmission Right of Way that will not mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will not limit or block access, or the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

CONTRACTOR - Corporation to whom the Vegetation Management work is awarded.

CONDUCTOR BLOWOUT – Conductors horizontal position/location at National Electrical Safety Code (NESC) designed wind and temperature.

CONDUCTOR SAG – Conductors vertical position/location at designed maximum operating conditions.

DANGER TREE – A tree that if it were to fall or be cut would be tall enough to strike electrical lines and equipment of the transmission or distribution system.

HAZARD TREE - A tree that is dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment of the transmission system if it falls or is cut.

INCOMPATIBLE VEGETATION – Vegetation within or outside the Transmission Right of Way that will mature to a height or size that will pose a grow-in, fall-in, or blowing-together threat to the transmission conductor, or that will limit or block access, or the safe and reliable operation, emergency restoration, or maintenance activity, which is typically within 25 feet of any Duke Energy facilities (towers, poles, guy wires, guy anchors, etc.).

INTEGRATED VEGETATION MANAGEMENT - Vegetation plan that combines various components including pruning, mowing, removals, and herbicide applications to manage the growth of vegetation on the electric utility rights-of-way.

LEGAL- Duke Energy Legal Department.

MAINTAINED/LANDSCAPED AREAS - An area where cut brush typically cannot be left on-site. Maintained areas typically include maintained yards and landscaped areas.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION (NERC) CIRCUITS – Transmission lines typically operated at more than 200 kV. Some transmission lines operated at voltages lower than 200 kV may be designated as NERC circuits if deemed critical.

SECTION 2 – DEFINITIONS CONTINUED

NON-NERC CIRCUITS – Transmission lines that typically operate at less than 200 kV.

NON-MAINTAINED/NON-LANDSCAPED AREAS - An area where cut brush can be left on-site. Non-Maintained areas are unimproved areas or natural areas.

RECLAMATION – The establishment or reestablishment of Integrated Vegetation Management (IVM) objectives in areas not actively maintained.

RIGHT-OF-WAY (ROW)- A strip of land that an electric utility uses to construct, operate, inspect, maintain, repair, or replace an overhead or underground power line. The ROW allows the utility to provide clearance from trees, buildings and other structures that could interfere with line installation, maintenance, and operation. ROW may include licenses, easements and other rights to access property.

TRANSMISSION LINE– A set of electrical conductors that carry 69 kV or more of electricity.

TREE- A perennial woody stem equal or greater than six inches in DBH (diameter at breast height)

SECTION 3 – FEDERAL, STATE, AND LOCAL LAWS

Contractor shall perform all work in conformance with the Duke Energy Kentucky Vegetation Management Program requirements and work specifications, Occupational Health and Safety Administration (OSHA) regulations, American National Standards Institute (ANSI) A300 and Z133, and all federal, state, county, and municipal laws, ordinances, and regulations applicable to said work.

The governing entities include but are not limited to:

- Kentucky Public Service Commission (Commission)
- Kentucky Transportation Cabinet (Department of Transportation)
- Kentucky Department of Agriculture
- Occupational Health and Safety Administration (OSHA)
- American National Standards Institute (ANSI)
- Easement and/or Permit Documents

SECTION 4 – PROPERTY ACCESS RIGHTS / REQUIREMENTS

The rights to access, inspect, or perform the work associated with vegetation management practices include, but are not limited to, established legal instruments, easements, public road rights-of-way, municipal ordinances, state statutes, regulatory rules, tariffs, and other legal authority. Personnel responsible for implementing vegetation management on behalf of Duke Energy Kentucky should, when necessary, utilize the available supporting documents to pursue the completion of necessary work activities to maintain vegetation growth to the established standards of acceptance in the provision of safe and reliable electric service. If there are objections, restrictions or limitations that prevent completion of the necessary work activities, Duke Energy Vegetation Management should contact the Land Services Department or Legal Department for specialized assistance.

A list of items to determine property access rights include, but are not limited to:

- Existing property easement, prescriptive easements, public road rights of way and / or agreements
- State statutes
- Municipal codes
- Commission rules, regulations, orders, and approved tariffs.

SECTION 5 – WORK QUALITY AND SAFETY STANDARDS

All work shall be performed in conformance with the governing rules from the following: Duke Energy Kentucky Vegetation Management Program Requirements, OSHA regulations*,* NESC and all federal, state, county, and municipal laws, statutes, ordinances, and regulations applicable to said work.

Clearance to obtain safety and reliable electric service are based on, but not limited to, consideration of the following:

National Electrical Safety Code (NESC)

ANSI A300 Standard - American National Standards Institute A300 for Tree Care Operations
- For utility line clearance work, the primary foci are Parts 1, 7 and 9.

ANSI Z133 Standard - American National Standards Institute Z133 for Tree Care Operations - Safety Requirements

OSHA Standard 29 Code of Federal Regulations (CFR) 1910.269 -OSHA Standard 29 CFR 1910.269 (a)(1)(i)(E) for Electric Power Generation, Transmission, and Distribution

Pruning Trees Near Electrical Utility Lines – A Field Pocket Guide for Qualified Line-Clearance Tree Workers by Dr. Alex L. Shigo

SECTION 6 – TRANSIMISSION VEGETATION MANAGEMENT OVERVIEW FOR PLANNED WORK

Duke Energy's program is designed on an Integrated Vegetation Management (IVM) strategy that targets removals of incompatible vegetation to minimize potential outages to the Transmission system and ensure necessary access within all transmission line corridors. The reason for IVM is to create, promote, and conserve sustainable plant communities that are compatible with the intended use of the site, and manage incompatible plants that may conflict with the intended use of the site. This approach is recognized as an industry best management practice and is in alignment with ANSI A300 Part 7 standard.

As part of an IVM strategy, Duke Energy utilizes a threat and condition-based approach to planned work. This approach of identifying threats as triggers to determine incompatible vegetation within and outside the Transmission Right of Way. Duke Energy utilizes a process to define compatible and incompatible vegetation to balance the needs of public and worker safety as well as the reliable operation of the Transmission system. A time-based herbicide program will be used to further manage the ROW of incompatible vegetation and support IVM.

THREAT/CONDITION-BASED TRIGGERS

For planned work, threat trigger distances are used to identify vegetation threats that do not allow for safe operation of the transmission facilities, under all operating conditions (designed blowout and designed maximum operating sag). These threat triggers are radial distances based on engineering design criteria for the conductor sag and blowout operating locations and are voltage dependent.

These threat trigger distances provide for approximately 6 years of typical vegetation re-growth and supports minimum safe worker distances. Once vegetation has been identified as a threat, the vegetation will be evaluated to determine a mitigation strategy through the work planning process.

THREAT/CONDITION-BASED ACTION

During the work planning and marking process, many factors and criteria must be considered when developing the mitigation strategy. A Duke Energy Kentucky utility vegetation management professional will evaluate the vegetation based on arboricultural, regulatory/safety standards, legal ROW rights and criteria such as size, age, location, growth rate, maintained/landscaped vs. non-maintained/non-landscaped, etc. Property owner concerns with the proposed mitigation strategy shall be communicated to Duke Energy Kentucky personnel and alternative mitigation strategies will be considered. One mitigation strategy includes herbicide application.

MITIGATION FOR INCOMPATIBLE VEGETATION THREATS

All identified incompatible vegetation will be evaluated and removed.

SPECIAL/SPECIFIC SITUATIONS

Potential Outage Risk: When a Transmission outage risk is identified, Duke Energy Kentucky will attempt to notify the affected property owner if practical and possible. However, Duke Energy Kentucky may need to take immediate action, such as remove the vegetation, to protect the reliability and security of the Transmission system.

Roadside: For situations such as roadside, overhead Transmission lines built within public road right of way with limited Transmission Right of Way rights, a Wire Zone / Border Zone approach will be utilized with property owners to manage vegetation threats within and outside of the public road right of way.

Off ROW Danger Tree: Duke Energy Kentucky personnel will focus on removing danger tree threats for reliability and storm hardening purposes on narrow corridors or rural areas where rights outside of the easement allow.

Storm: During storm events, debris in maintained or landscaped areas associated with emergency operations restoration efforts will be left on site and is the responsibility of the property owner.

SECTION 7 – INSPECTION AND MONITORING

Duke Energy Kentucky can and may perform inspections on each transmission circuit (69kv and above) to observe vegetation conditions on the transmission system. These inspections should provide for the capabilities to specifically identify potentially incompatible vegetation conditions. The intent of these inspections is to identify off-cycle vegetation threats along the transmission line corridors and take appropriate action.

SECTION 8 – VEGETATION CONTROL METHODS

TREE PRUNING - Trees found within or adjacent to the right-of-way edge will, in most cases, encroach upon the electrical conductors through the growth of their limbs. The management of these trees requires the removal or partial removal of those potentially interfering limbs. Industry standards dictate the proper methods of "pruning" such limbs to minimize any damages to the tree. These methods are in alignment with industry standards which refer to natural pruning, drop crotch and lateral pruning techniques. Stubbing and tearing of bark shall be avoided. When utilizing boom mounted cutting devices or helicopters to perform the pruning activities in rural locations, proper pruning methods are not typically a viable option.

HAZARD TREE MITIGATION - Trees found within or adjacent to the right-of way that are dead, structurally unsound, diseased, shallow-rooted, leaning or otherwise defective that could strike electrical lines or equipment are targeted to be taken down. Stumps from downed trees shall be treated with herbicides where appropriate and possible.

INCOMPATIBLE VEGETATION MITIGATION (i.e., trees)- Trees which are in close proximity to electrical facilities can require extensive pruning to prevent them from causing reliability or safety risk. These trees within the right- of-way will be targeted to be taken down and Duke Energy Kentucky will attempt to notify the affected property owner.

BRUSH MANAGEMENT - Because of a variety of terrain, differences in soil, land use, and vegetation types, Duke Energy Kentucky uses IVM practices which include environmentally acceptable herbicides to control brush within the right-of-way. All herbicides used in brush management operations shall be registered with the EPA and the applicable regulating state authority. In situations where brush height is of significant size and therefore not conducive to herbicide applications, the right of way may be mechanically mowed. In landscaped/maintained areas, brush will typically be hand cut and the remaining stumps treated.

SECTION 9 – CONTRACTOR RESPONSIBILITIES

STANDARDS TO FOLLOW - Contractor shall perform all work in conformance with Duke Energy Kentucky Vegetation Management Program requirements (Contract Terms and Conditions).

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

CHRISTOPHER R. BAUER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christopher R. Bauer and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director, Corporate Finance and Assistant Treasurer. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

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

A. I received a Bachelor of Arts degree from Flagler College in 2003 and an MBA degree from the University of North Florida in 2004. I am a licensed Certified Public Accountant in the state of Florida. From 2004 to 2010, I worked in Deloitte's Audit and Enterprise Risk Services unit, providing financial statement and internal control services across various industries. In 2010, I joined Duke Energy as a Lead Audit Consultant in the Internal Audit Department. In 2015, I moved to Duke Energy's Investor Relations group where I served as a Manager responsible for communicating the company's strategic, operating and financing plan to debt and equity investors and external stakeholders. In 2017, I moved to the Treasury department and served as both a Treasury Director and the Director of Credit & Capital Markets before assuming my current role in early 2021.

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

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

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

A. Yes. I have previously testified before the Commission.

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

A. My testimony will address Duke Energy Kentucky's financial objectives, capital structure, and cost of capital. I will also discuss the current credit ratings and forecasted capital needs of Duke Energy Kentucky. Throughout my testimony, I will emphasize the importance of Duke Energy Kentucky's continued ability to meet its financial objectives and maintain strong credit quality. I sponsor the following information that I used in preparing my financial forecasts in this case: Duke Energy's dividend policy; Duke Energy Kentucky's debt rate assumptions; existing short-term and long-term debt balances; sales of accounts receivable; capital lease and equipment lease information; and information relating to the long-term debt financing.

I sponsor Filing Requirements (FR) FR 12(2)(a), FR 12(2)(b), FR 12(2)(c), FR 12(2)(d), FR 12(2)(e), FR 12(2)(f), FR 12(2)(g), FR 12(2)(h) and FR16(7)(j), FR 16(7)(l) and FR 16(7)(r). I sponsor Schedules J-1, J-2, J-3, and J-4 in response to FR 16(8)(J). Finally, I provided certain information to Duke Energy Kentucky witness Mr. Grady "Tripp" S. Carpenter for his use in preparation of FR 16(7)(h) and Schedule K in response to FR 16(8)(k), respectively.

II. DUKE ENERGY KENTUCKY'S FINANCIAL OBJECTIVES

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

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

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

A. The benefits of achieving and maintaining a strong, investment-grade, credit rating includes lower overall financing costs and greater access to the capital markets, thus improving Duke Energy Kentucky's ability to maintain a safe, reliable, and low-cost level of service.

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

A. As explained by Duke Energy Kentucky witness Amy B. Spiller, Duke Energy Kentucky is requesting an overall increase of approximately $75.2 million. As part of this request, supported by the analysis and testimony of Duke Energy Kentucky witness Mr. Joshua C. Nowak, the Company is requesting an allowed return on equity (ROE) of 10.35 percent. The proposed capital structure in this request is comprised of 52.505 percent equity and 47.495 percent debt. Approval of the Company's request in this case will support its financial objectives by ensuring timely cash recovery of its prudently incurred costs.

III. CREDIT QUALITY & CREDIT RATINGS

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

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

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

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

A. Investors, investment analysts, and the rating agencies regard consistent and predictable regulation as one of the most important factors in assessing a utility company's financial strength. These stakeholders want to be confident a utility company operates in a stable regulatory environment that will allow the company to recover prudently incurred costs and earn a reasonable return on investments necessary to meet the demand, reliability, and service requirements of its customers. Important considerations include the allowed rate of return, cash quality of earnings, timely recovery of capital investments, stability of earnings, and strength of its capital structure. Positive consideration is also given for utilities operating in states where the regulatory process is streamlined and outcomes are equitably balanced between customers and investors.

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

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

Rating Agency	**S&P**	**Moody's**
Senior Unsecured Rating	BBB+	Baa1
Outlook	Stable	Stable

There are four key factors which drive the credit ratings of the electric and gas utility sector: regulatory framework, ability to recover costs and earn returns, diversification and financial strength. A gas or electric utility in the Baa range is described by Moody's as having (i) a regulatory framework where rates are set in a manner that will permit the utility to make and recover all prudently incurred investments, (ii) a regulatory environment that is consistent and predictable, (iii) timeliness in the recovery of operating and capital costs, (iv) rates that are set at a level where attracting capital is sufficient without difficulty, and (v) adequate financial metrics.

S&P and Moody's ratings differ but are analogous. S&P modifies its ratings with the use of a plus or minus sign to further indicate the relative standing within a major rating category. For example, a "BBB+" credit rating is at the higher end of the "BBB" credit rating category and a "BBB-"is at the lower end of the category. Moody's credit rating assignments use the numbers

"1", "2" and "3", with the numbers "1" and "3" analogous to a "+" and "-", respectively. For example, Moody's credit ratings of "Baa1" and "Baa3" would be analogous to "BBB+" and "BBB-" credit ratings at S&P.

The ratings outlook assesses the potential direction of a long-term credit rating over an intermediate term (typically six months to two years). Duke Energy Kentucky's "Stable" outlook at S&P and Moody's is an indication the credit ratings are not likely to change at this time, however a change in outlook or rating could occur if the Company experiences a change in its business, regulatory or financial risk.

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

A. Duke Energy Kentucky's current senior unsecured credit ratings were established by Moody's in November 1995 and by Standard & Poor's in April 2015. On December 15, 2020, S&P revised its outlook to "negative" from "stable" on Duke Energy Corp. and subsidiaries, including Duke Energy Kentucky. On January 26, 2021, S&P downgraded the senior unsecured ratings of Duke Energy Corp. and subsidiaries, including Duke Energy Kentucky to "BBB+" from "A-" and returned the outlook to "stable."

S&P utilizes a family rating methodology, whereby the credit rating and outlook of the parent company, Duke Energy Corporation, is applied to each of the parent's subsidiaries. S&P's "stable" outlook is predicated on the expectation that Duke Energy Corp. and subsidiaries will be able to manage regulatory risk while capital spending remains high.

Moody's affirmed its Baa1 rating and stable outlook in January 2022.

Q. DOES DUKE ENERGY KENTUCKY COMPETE FOR INVESTORS IN THE CAPITAL MARKETS? PLEASE EXPLAIN.

A. Yes. When evaluating investment alternatives, fixed income investors use a set of criteria similar to that of the rating agencies. Fixed income investors will evaluate both credit strengths and challenges to determine the overall risk of the investment. Fixed income investors make investments for up to 40 years of duration and therefore consistency and predictability of business risk including a stable regulatory environment is imperative. If the regulatory environment in Kentucky becomes unsupportive or unpredictable, investors would likely look to alternative fixed income investments that provide similar returns with lower perceived risk. In addition, if Duke Energy Kentucky's credit rating is in jeopardy, the risk of investing in the Company's debt securities would increase. In order to compensate for the increased risk, investors would require a higher rate of return. This would increase the cost of future debt issuances, which are passed through to customers. Just as the Company must compete for capital among fixed income investors in the debt capital markets, it must also be well positioned against its peers to attract equity capital. A pivotal factor in any investment decision is the risk-return profile of the subject company. Authorized ROE is of paramount importance because it sets a cap on the regulated company's ability to earn a return on invested capital and share that return with equity investors. If the Commission were to adopt an unreasonable ROE it could negatively impact Duke Energy Kentucky's ability to attract debt and equity capital on reasonable terms, especially in times of financial stress or under volatile market conditions.

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

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

Q. PLEASE EXPLAIN WHY MAINTAINING CREDIT QUALITY AND CREDIT RATINGS ARE BENEFICIAL TO CUSTOMERS.

A. To assure reliable and cost-effective service, and to fulfill its obligations to serve customers, the Company must continuously plan and execute major capital projects. This is the nature of regulated, capital-intensive industries like electric and gas utilities. The Company must be able to operate and maintain its business without interruption and refinance maturing debt on time, regardless of financial market conditions. The financial markets continue to experience periods of high volatility, most recently driven by the COVID-19 pandemic, geopolitical events and the uncertainty surrounding fiscal and monetary policy to address a weakening economy and decades high inflation. Duke Energy Kentucky must be able to finance its needs throughout such periods and strong investment-grade credit ratings provide the Company greater assurance of continued access to the capital markets on reasonable terms during periods of elevated volatility.

Q. PLEASE EXPLAIN THE CONCEPT OF FUNDS FROM OPERATIONS (FFO) AND THE IMPORTANCE OF THE RATIO BETWEEN FFO AND DEBT.

A. The Funds from Operations (FFO) to Debt calculation is a key leverage metric utilized by the credit rating agencies when determining the credit rating and rating outlook of a company such as Duke Energy Kentucky. The numerator of the equation (FFO), also referred to as Cash Flow from Operations Pre-Working Capital (CFO Pre-WC) by Moody's Investor Services (Moody's), is comprised of the operating cash flows of the company with certain proprietary adjustments made by the rating agencies. The denominator is the total debt of the company. The result of the calculation is a percentage that represents the cash flows of the company, generated annually compared to total leverage.

To maintain the current ratings by S&P and Moody's respectively, certain downgrade thresholds for this key metric have been established for which Duke Energy Kentucky must remain above. Unfavorable regulatory outcomes will negatively impact the calculation. For example, a lower equity ratio would result in reduced FFO and higher leverage. A lower allowed ROE would also lower FFO, weakening the key metric. Moody's current rating outlook of 'Stable' for Duke Energy Kentucky reflects a credit supportive regulatory environment and the expectation that, over the next two years, the utility will demonstrate a ratio of FFO to debt in the high teens. Further, Moody's explains that factors that could lead to a downgrade include a decline in the credit supportiveness of the regulatory environment in Kentucky, higher capital expenditures resulting in a material increase in debt levels, or the ratio of FFO to Debt remaining below 17 percent.

Beginning in 2018, Duke Energy Kentucky's credit metrics have been negatively impacted by the effects of tax reform and increased debt funding for capital expenditures. As of September 2021, the ratio of FFO to Debt was 16.0 percent, which is below the 17 percent downgrade threshold. Based on its most recent credit opinion, Moody's expects Duke Energy Kentucky's FFO to Debt to improve and stabilize in the high teens going forward.

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

A. As of the most recent publications of the Company's credit opinions, the rating agencies believe the Kentucky regulatory environment generally supports long-term credit quality with timely and sufficient recovery of prudently incurred costs and expenses, including recovery of fuel, purchased power, and environmental compliance costs, which are supportive of credit quality. Generally speaking, the agencies have identified the following strengths and challenges when assessing the credit quality of Duke Energy Kentucky:

Credit Strengths:

- Financial metrics expected to improve and stabilize;
- Generally credit supportive regulatory environment in Kentucky; and

- Support from the Duke Energy corporate family.

Credit Challenges:

- Credit metrics are below historic highs;
- Relatively small size compared to other integrated utilities; and
- Poorly positioned for the carbon transaction.

Q. WHAT FACTORS COULD LEAD TO A CREDIT DOWNGRADE AT DUKE ENERGY KENTUCKY?

A. For rate-regulated utilities, the regulatory environment and how the utility adapts to that environment is the most important credit consideration made by the credit rating agencies. The ability to recover prudently incurred costs timely and earn a fair return is foundational to a utility's credit quality. Therefore, if there is a decline in the credit supportiveness of the regulatory environment, such as delays in recovery of prudently incurred costs through the absence of rider mechanisms or a reduced ROE and equity layer, it could lead to weaker financing credit metrics and could result in a credit downgrade. Such an event could, in turn, negatively impact the Company's ability to access the financial markets on reasonable terms, and ultimately, increase the Company's costs to borrow funds. This, in turn, could result in increased costs to customers.

Q. HOW WILL DUKE ENERGY KENTUCKY ADDRESS RATING AGENCY CONCERNS THAT IT IS POORLY POSITIONED FOR THE CARBON TRANSITION?

A. The rating agencies have stated in recent reports that a credit challenge of Duke Energy Kentucky's is that the company is poorly positioned for carbon transition risk. In 2021, Duke Energy Kentucky ceased all marketing efforts to place $50 million of unsecured debentures with private placement investors after days of management presentations. The decision to cancel the transaction was due to feedback and aggressive demands from both existing and potential new investors. The Company found that a growing number of asset managers have enacted new policies to limit exposure to utilities that have high levels of coal-fired/ high carbon emitting generation. Without a clear and publicly communicated transition path away from coal generation to a cleaner fuel source, some investors simply would not entertain an order of any size and at any price. The private placement market is less liquid than the larger public taxable debt markets. There are a limited number of private placement investors and the number of those investors with new or emerging environmental mandates or strategies has grown rapidly over the past several years. These environmental mandates will continue to limit investor's ability to invest in coal-heavy utilities that do not have a clear transition plan.

A lack of a clear strategy will continue to limit Duke Energy Kentucky's access to credit or make it more expensive to access credit at the customer's expense. Several Company witnesses in this proceeding discuss Duke Energy Kentucky's anticipated retirement of the East Bend coal station in 2035, including Company Witness Quilici, Luke, Lawler, Swez, and Park. This retirement in 2035 will address the rating agencies concerns and send a clear message to new and existing investors and will restore the Company's access to the debt capital markets.

IV. CAPITAL STRUCTURE AND COST OF CAPITAL

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

A. As mentioned earlier in my testimony, Duke Energy Kentucky's proposed capital structure is comprised of 47.495 percent debt and 52.505 percent equity, after making adjustments for purchase accounting and other items. The Company believes this proposed capital structure is the appropriate capital structure for Duke Energy Kentucky, as it introduces an appropriate amount of risk due to leverage and minimizes the weighted average cost of capital to customers. Approval of the proposed capital structure will help Duke Energy Kentucky maintain its credit quality to meet its ongoing business objectives. This level is also consistent with the Company's target credit ratings.

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

A. Duke Energy Kentucky witness Josh Nowak testifies regarding the Company's cost of equity. The Company supports Mr. Nowak's analysis and is requesting 10.35 percent as the Company's allowed ROE.

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

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

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

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

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

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

Q. IS IT APPROPRIATE TO CONSIDER DUKE ENERGY CORPORATION'S CAPITAL STRUCTURE WHEN DETERMINING THE CAPITAL STRUCTURE FOR DUKE ENERGY KENTUCKY?

A. No. Duke Energy Corporation is a non-regulated entity that sits outside of the jurisdiction of the Kentucky Public Service Commission. Comparing the capital structures of a non-regulated business to that of a regulated business is not appropriate. Duke Energy Kentucky funds its operations through retained earnings and the issuance of debt. The capital structure on its balance sheet is its true capital structure. The assets obtained by Duke Energy Kentucky to serve customers were financed in a manner consistent with the Company's capital structure as a regulated utility, not that of a parent-level holding company. Duke Energy Corporation's capital structure is significantly influenced by strategic transactions, for example acquiring other companies such as Progress Energy and Piedmont Natural Gas. Transactions such as these have increased Duke Energy Corporation's diversity and scale, ultimately improving the credit profile of the company. They have also delivered benefits to Duke Energy Kentucky customers, such as reduced O&M costs due to operational efficiencies, yet those customers have not paid for the debt incurred at the holding company. Arbitrarily imposing a holding company capital structure upon Duke Energy Kentucky would significantly increase its leverage (and, therefore, financial risk), reduce its cash flows, and erode credit quality, all to the detriment of the customers through higher borrowing costs.

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

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

	Base Period (at February 2023)	**Forecast Period** (Avg of Jun 2023 thru Jun 2024)
Short-Term Debt (Schedule J-2)	4.899 percent	4.739 percent
Long-Term Debt (Schedule J-3)	4.163 percent	4.377 percent

For Schedule J-2, which calculates cost of short-term debt, the assumed Amount Outstanding for Sale of Accounts Receivables, for both the base and forecast period, was the average of the actual monthly balances for Duke Energy Kentucky's Sale of Account Receivables during the trailing twelve months as of July 2022. The assumed interest rate on this debt for the base and forecast period was derived using

Bloomberg's Implied forward curve for one-month Term Secured Overnight Financing Rate (SOFR) as of September 2022 plus an 85 basis point credit spread.

Duke Energy Kentucky utilizes an accounts receivable sale program in order to provide capital diversification at economic funding costs and as a means to contribute floating rate exposure to the Company's overall debt portfolio. The program is not used as a working capital facility, but rather as an alternative to other long-term borrowing arrangements. Please refer to Company witness Danielle L. Weatherston's testimony for a discussion of cash flows related to Duke Energy Kentucky's accounts receivable sale program.

The Amount Outstanding for the Notes Payable to Associated Companies in the forecasted short-term debt schedule is the thirteen-month average of Duke Energy Kentucky's monthly money pool borrowing balance from current company projections. The interest rate on this debt was derived using Bloomberg's implied forward curve for one-month LIBOR as of September 2022.

For Schedule J-3, which calculates the cost of long-term debt, the interest rate on $25 million of LT Commercial Paper for the base and forecast period was derived using Bloomberg's Implied forward curve for one-month LIBOR as of September 2022 plus a 25 basis point credit spread. One long-term, senior unsecured, debt issuance totaling $130 million is forecasted for September 2023, based on company projections. The interest rate on this future issuance was estimated using a weighted average of Bloomberg's forward curves for the 5-year, 10-year and 30-year US Treasury yield, respectively, as of September 2022 plus a 220 basis point credit spread for the 5 year debt offering, 255 basis point credit spread for the 10 year debt offering and a 280 basis point credit spread for the 30 year debt offering.

V. DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS

Q. WHAT ARE DUKE ENERGY KENTUCKY'S CAPITAL REQUIREMENTS DURING THE 2023-2025 TIME PERIOD?

A. Duke Energy Kentucky faces substantial capital needs over the next several years to satisfy debt maturities, upgrade aging infrastructure, and to further invest in energy efficiency. The Company's capital requirement for the regulated business of Duke Energy Kentucky is projected to be approximately $885 million during the period – 2023-2025. This amount consists of approximately $715 million in projected capital expenditures and approximately $170 million in debt maturities.

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

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

VI. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

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

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

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

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

September 30, 2022.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. PLEASE DESCRIBE SCHEDULES J-1.

A. These J schedules are embodied in FR 16(8)(j). Specifically, Schedule J-1, entitled "Cost of Capital Summary" sets forth the projected capital structure and capitalization ratios of Duke Energy Kentucky at February 28, 2023, and the average of the projected balances and rates for the thirteen-month period ending June 30, 2024. The weighted cost of the various capital components is computed by multiplying the respective capitalization ratio by the computed annualized cost rate. The overall weighted cost of capital is reflected in the rate of return requested for the thirteen-month period ending June 30, 2024.

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

A. Schedule J-2, entitled "Embedded Cost of Short-Term Debt," and Schedule J-3, entitled "Embedded Cost of Long-Term Debt," set forth the calculations of the cost of short-term debt and long-term debt, respectively, of Duke Energy Kentucky. The information on page 1 of these schedules was computed at the date of the base period, February 28, 2023. On page 2, the balances and interest rates are based on the average of the projected balances and rates for the thirteen-month period ending June 30, 2024.

Q. WHY IS SCHEDULE J-4 NOT INCLUDED?

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

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

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

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

A. The information I sponsor includes Duke Energy Kentucky's senior unsecured credit ratings. I also provided information relating to consolidated capital structure and common stock related data to Ms. Danielle L. Weatherston for her use in preparing Schedule K.

VII. CONCLUSION

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

A. Yes.

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

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Christopher Bauer, Director Corporate Finance – Assistant Treasurer, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Christopher Bauer Affiant

Subscribed and sworn to before me by Christopher Bauer on this 30th day of November, 2022.

VIRGINIA M. ADAMS
NOTARY PUBLIC
MECKLENBURG COUNTY, NC
My Comm. Expires October 2, 2026

NOTARY PUBLIC

My Commission Expires: 10/2/26

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

GRADY "TRIPP" S. CARPENTER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Grady "Tripp" S. Carpenter and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

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

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

A. I have a Bachelor of Science degree in Business Administration with a Finance concentration from the University of North Carolina at Wilmington and a Master of Accounting degree from the University of North Carolina at Chapel Hill. I am a licensed Certified Public Accountant in the state of North Carolina. After nine years working in various roles within public accounting and private industry, I joined Duke Energy as a senior accounting analyst in 2013. Subsequently, I held various positions of increasing responsibility within the Controller's and Financial Planning and Analysis departments. In 2021, I became the Forecasting Manager for Duke Energy Ohio and its subsidiary, Duke Energy Kentucky, Inc. (Duke Energy Kentucky).

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS MANAGER FINANCIAL FORECASTING II.

A. I am responsible for preparing the budgets and forecasts as well as performing financial analysis for Duke Energy Kentucky and Duke Energy Ohio's electric and natural gas utilities.

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

A. No.

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

A. My testimony will address Duke Energy Kentucky's budgeting and forecasting process underlying the projected data for the test year proposed in this Application. I also discuss the budget variance reports, which provide the variance analysis for the test period. I sponsor and support the forecasted operating revenues and expenses prior to proforma adjustments and the long-term financial forecast that were prepared under my direction and control. I sponsor Filing Requirements (FR) 16(6)(a), 16(6)(b), 16(6)(d), 16(6)(e), 16(7)(b), 16(7)(c), 16(7)(d), 16(7)(f), 16(7)(g), 16(7)(h), and 16(7)(o). In response to FR 16(8)(b), I co-sponsor Schedules B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, and B-4 with Duke Energy Kentucky witness Ms. Huyen C. Dang. I sponsor the information contained in B-5 and B-5.1. Company witness Mr. Paul M. Normand provided me with the cash working capital included in these schedules as supported by the lead-lag study he prepared. I also sponsor certain information contained in Schedule B-

8 that is also supported by Duke Energy Kentucky witness Ms. Danielle L. Weatherston. In response to FR 16(6)(a), 16(6)(b) and 16(8)(d), I sponsor Schedules D-2.1 through D-2.16. I also sponsor the forecasted data on Schedules I-1 through I-5 in response to FR 16(8)(i), and Schedule K in response to FR 16(8)(k).

II. THE BUDGETING AND FORECASTING PROCESS

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

A. The forecasted data used in these proceedings is based on Duke Energy Kentucky's 2022 and 2023 annual budgets. The Company is also using a fully forecasted test period that, for this proceeding, spans the twelve-month period ending June 30, 2024. The budget and forecast were reviewed and approved by Duke Energy Kentucky's executive management and Duke Energy's Board of Directors. Updates to the forecast may be made for material changes that occur that were not known at the time of Board approval. Those changes are reviewed by executive management.

Q. HOW DID YOU USE THE 2022 AND 2023 ANNUAL BUDGETS RESULTS FOR THE BASE AND FORECASTED PERIODS IN THIS PROCEEDING?

A. The base period is the twelve months ending February 28, 2023 and consists of six months of actual data through August 31, 2022 and the remaining six months of budgeted data. The forecasted test period is the twelve months ending June 30, 2024. The Company's 2022 actual data and 2022 and 2023 budgets were the starting point for the preparation of both the base and forecasted periods. A simplistic high-level summary of that approach is as follows. First, I revised the 2022 and 2023 Annual Budgets for a limited number of updated assumptions, as I describe in detail later in my testimony. Next, I extended the revised 2023 Annual Budget to June 2024 using the Company's standard forecasting methodology, which I also describe later in my testimony when I explain how I prepared the financial forecasts.

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

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

Q. DESCRIBE THE GUIDELINES PROVIDED BY THE FORECAST SYSTEMS AND REPORTING ORGANIZATION IN DEVELOPING DUKE ENERGY KENTUCKY'S ANNUAL RESPONSIBILITY (OPERATING AND MAINTENANCE) CENTER BUDGET.

A. The guidelines provided by the Forecast Systems and Reporting organization are a detailed set of instructions for creating a responsibility center budget. For example, there are detailed instructions for budgeting employee labor data, such as the escalation rates for union and non-union labor expenses and fringe benefit loading rates. Detailed instructions for non-labor related expenses, such as transportation (fleet) expenses, are included along with instructions for handling contract labor. The Company follows internal capitalization guidelines when identifying a capital versus expense item. Budget coordinators are required to use these assumptions and/or instructions in projecting their future departmental expenses. These operating and maintenance (O&M) budgeting guidelines are reflected in the budgets and forecasts that are submitted to Duke Energy Kentucky's executive management and Duke Energy's Board of Directors for approval and are also reflected in the forecasted financial data in these proceedings.

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

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

1. Operating revenues;
2. Projected fuel, purchased power, emission allowance, other production costs and off-system sales;
3. Depreciation;

4. Property taxes;
5. Other Income and Expense, primarily allowance for funds used during construction (AFUDC);
6. Financing assumptions, including short- and long-term debt rates, dividend policy, issuances and redemptions, accounts receivable sales and capital leases; and
7. Tax rates and tax depreciation.

III. METHODOLOGY FOR THE FORECASTED DATA

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

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

A. INCOME STATEMENT

Q. PLEASE DESCRIBE HOW THE OPERATING REVENUES WERE FORECASTED.

A. The first step in preparing the operating revenues for the 2022 and 2023 annual budgets was to obtain a forecast of the projected electric kilowatt per hour (kWh) sales and natural gas sales on a thousand cubic feet basis (MCF) from Duke Energy Kentucky witness Max W. McClellan, Lead Load Forecasting Analyst, who prepared the load forecasts on a monthly basis. The forecasts are updated at least annually. The Load Forecasting and Fundamentals organization also provides the forecasted number of customers for each customer class. The projected revenues for the annual budget and the long-range forecast for kWh and MCF sales were calculated by applying the tariff charges and base customer charges to these sales and customer forecast numbers for all electric and natural gas residential customers. The projected revenue for electric and natural gas non-residential customers was calculated by applying average realizations to their respective kWh and MCF sales forecasts.

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

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

Q. HOW WERE OTHER REVENUES PROJECTED?

A. Other revenue categories, such as PJM reactive revenues, reconnection charges, *etc.*, for Duke Energy Kentucky's 2022 and 2023 Annual Budgets are projected based on historical trends or are provided by the individual budget centers. Additionally, Duke Energy Kentucky witness John D. Swez used the GenTrader Model to provide me with forecasts of the power production costs, such as fuel, emission allowances and purchase power costs, and revenues, such as off-system sales, after applying the Company's off-system sales sharing mechanism (Rider PSM).

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

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

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

A. The forecasted depreciation for existing and projected electric and natural gas plant is calculated by multiplying the depreciable plant by appropriate composite depreciation rates. These composite rates for electric generation, transmission, distribution, common and general plant are based on rates currently in effect and established in the Company's 2017 electric base rate case, Case No. 2017-00321. The composite rates proposed in the Company's last electric base rate case, Case No. 2019-00271 were denied by the KPSC and therefore the rates from the previous case are the authorized rates of record the Company currently uses for actuals and budgeting.

The projected electric and natural gas capital budget data was prepared by the responsibility centers for a five-year period at the time of the 2022 and 2023 Annual Budgets preparation per Duke Energy's capital budgeting process, which I discussed earlier. The electric capital budget data was obtained from Duke Energy's operating functions, including the distribution, transmission and generation organizations. These numbers were revised to reflect the latest cost estimates and timing of capital expenditures for various projects designed to maintain or enhance reliability and service to customers including construction projects at the East Bend station for compliance and reliability initiatives. These projects are described in the direct testimonies of Mr. William C. Luke and Mr. Dominic "Nick" J. Melillo, respectively.

Q. DESCRIBE HOW O&M EXPENSES ARE INCLUDED IN THE FORECAST.

A. The O&M expenses, including benefits and payroll taxes, were obtained from the 2022 and 2023 Annual Budgets by the various responsibility centers, using the bottom-up approach that I described above. Duke Energy Kentucky's proportionate share of the shared services expenses and the corporate center O&M expenses are assigned and/or allocated from the service company to Duke Energy Kentucky and are also derived using the same bottom-up approach. The allocated share is derived by the application of appropriate allocations based on the service company allocation factors, and in accordance with various Commission-approved service agreements as discussed in the direct testimony of Duke Energy Kentucky witness, Mr. Jeffrey R. Setser. For labor-related expenses, I used the projected annual labor cost rate increases provided by Duke Energy Kentucky witness Mr. Jacob J. Stewart to budget 2022 and 2023 union and non-union employee labor expense. Union labor cost increases were assumed to be between 2.0 percent and 3.5 percent, depending on the agreements, while non-union labor cost increases were assumed to be 3.5 percent (including both merit increases of 3 percent and an allowance for salary increases for promotions of 0.5 percent). I also used the fringe benefit loading rates (26.11 percent for 2022 and 2023) and payroll tax (7.5 percent in each year) loadings. Non-labor expenses for 2022 and 2023 were forecasted by the responsibility centers based on their knowledge and expectations for various costs.

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

A. As mentioned above, O&M budgets were supplied by the responsibility centers for 2022 and 2023 per the company's Budget Guidelines. The basis for the 2024 budget is the 2023 budget adjusted for planned labor cost increases and other various O&M expenses that are expected to diverge from 2023 amounts.

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

Q. HOW DID YOU OBTAIN THE PROPERTY TAX EXPENSE?

A. Duke Energy Kentucky witness Mr. John R. Panizza supplied the property tax expenses for the forecasted financial test period data, based on the capital projections and forecasted plant balances.

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

A. The "other income and expense" is a below-the-line item and is derived from a combination of sources. The amount of funds for the AFUDC was derived from the electric and natural gas capital forecasts prepared for the 2022 and 2023 Annual Budgets. These capital forecasts were supplied by Duke Energy Kentucky's operating functions, including the distribution, transmission and generation organizations.

Q. HOW DID YOU OBTAIN THE INCOME TAX EXPENSE?

A. Mr. Panizza provided the appropriate income tax rates and the amortization of investment tax credit (ITC) and Excess Accumulated Deferred Income Taxes (EDIT). The income tax expense was derived using Utilities International (UI) Planner or "proprietary forecasting" software for each month of the revised 2022-2023 annual budget period and the 2024 forecast, by applying statutory income tax rates to applicable taxable book income and adjusting the resulting applicable income taxes by the ITC and EDIT amortization amounts.

B. BALANCE SHEET STATEMENT

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

A. The final month of actual data for the base period was the August 31, 2022 balances. Ms. Dang supplied the net book value for the existing electric, natural gas, general and common plant, and construction work in progress for the period ending August 31, 2022. I used the proprietary forecasting software to calculate the depreciation expense and net electric, natural gas, general and common plant and construction work in progress balances for the forecasted period.

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

A. Mr. Melillo and Mr. Luke provided the capital expenditures for the forecasted portion of the base period and for the forecasted test period. All of the forecasted capital data was prepared for the 2022 and 2023 Annual Budgets and was completed for a five-year period as typically done.

In addition, Ms. Weatherston supplied the plant inventories for emission allowances, coal, oil and gas and materials and supplies.

C. <u>CASH FLOW STATEMENT</u>

Q. HOW DID YOU PREPARE THE CASH FLOW STATEMENT FOR THE 2022 AND 2023 ANNUAL BUDGETS?

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

IV. <u>REASONABLENESS OF THE FORECASTED TEST PERIOD DATA</u>

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

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

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

A. Yes.

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

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

V. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

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

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

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

A. FR 16(6)(b) requires that the forecasted adjustments are limited to the twelve months immediately following the suspension period.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. PLEASE DESCRIBE SCHEDULE B-5.

A. Schedule B-5 is a summary of the jurisdictional working capital comprised of the cash element of working capital, material and supplies inventory, fuel inventory, emission allowance inventory and prepayments. The cash working capital calculation is based on the lead-lag study supported by Mr. Normand.

Q. PLEASE DESCRIBE SCHEDULE B-5.1.

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

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

A. The materials and supplies shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of period balance for the base period. These supplies consist primarily of supplies kept on hand in the Company's storerooms. These investments assure that adequate supplies are available to provide reliable service to customers. The 13-month average of material and supplies included in electric working capital for the forecasted test period is $18,675,789.

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

A. The fuel and emission allowance inventories shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of period balance for the base period. The 13-month average balances of fuel and emission allowance inventories included in electric working capital for the forecasted test period are $26,060,565 and $0, respectively. Emission allowance balances have been removed from the forecasted test period since emission allowances are included for recovery in the Company's Environmental Surcharge Mechanism (Rider ESM).

Q. PLEASE EXPLAIN THE PREPAYMENTS ON SCHEDULE B-5.1.

A. The prepayments shown on Schedule B-5.1 represent the 13-month average for the forecasted period and the end of the period balance for the base period. The 13-month average balances of prepayments in electric working capital for the forecasted test period are $497,555 related to prepaid insurance.

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

A. Cash working capital was computed for both the base and forecasted periods. It represents the financing incurred to bridge the gap between the time when expenditures are incurred to provide service and the time when payment is received for that service. The cash working capital computation is based upon the lead-lag study sponsored by Mr. Normand. For the base period, the resulting jurisdictional cash working capital is $12,170,358 and for the forecasted period cash working capital is $5,424,742.

Q. PLEASE DESCRIBE SCHEDULE B-8.

A. Schedule B-8 includes the comparative balance sheets for Duke Energy Kentucky. I sponsor the forecasted data included on this schedule.

Q. PLEASE DESCRIBE SCHEDULE D-2.1.

A. Schedule D-2.1 adjusts base period revenue to the level included in the forecasted test period. The adjustment results in a net revenue decrease of $35,148,862.

Q. PLEASE DESCRIBE SCHEDULE D-2.2.

A. Schedule D-2.2 adjusts base period fuel and purchased power expenses to the level included in the forecasted test period. The effect of the adjustment on Duke Energy Kentucky's electric operations is a decrease in pre-tax operating expenses of $32,595,978.

Q. PLEASE DESCRIBE SCHEDULE D-2.3.

A. Schedule D-2.3 adjusts base period other production expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $3,401,022.

Q. PLEASE DESCRIBE SCHEDULE D-2.4.

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

Q. PLEASE DESCRIBE SCHEDULE D-2.5.

A. Schedule D-2.5 adjusts base period transmission expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $100,458.

Q. PLEASE DESCRIBE SCHEDULE D-2.6.

A. Schedule D-2.6 adjusts base period regional market expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $458,443.

Q. PLEASE DESCRIBE SCHEDULE D-2.7.

A. Schedule D-2.7 adjusts base period electric distribution expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $114,298.

Q. PLEASE DESCRIBE SCHEDULE D-2.8.

A. Schedule D-2.8 adjusts base period customer accounts expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $900,338.

Q. PLEASE DESCRIBE SCHEDULE D-2.9.

A. Schedule D-2.9 adjusts base period customer service and information expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $23,583.

Q. PLEASE DESCRIBE SCHEDULE D-2.10.

A. Schedule D-2.10 adjusts base period sales expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in pre-tax operating expenses of $850,624.

Q. PLEASE DESCRIBE SCHEDULE D-2.11.

A. Schedule D-2.11 adjusts base period administrative and general expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $860,481.

Q. PLEASE DESCRIBE SCHEDULE D-2.12.

A. Schedule D-2.12 adjusts base period other operating expenses to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease of pre-tax operating expenses of $3,568,735.

Q. PLEASE DESCRIBE SCHEDULE D-2.13.

A. Schedule D-2.13 adjusts base period depreciation expense to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $2,891,056.

Q. PLEASE DESCRIBE SCHEDULE D-2.14.

A. Schedule D-2.14 adjusts base period taxes other than income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is an increase in pre-tax operating expenses of $3,210,283.

Q. PLEASE DESCRIBE SCHEDULE D-2.15.

A. Schedule D-2.15 adjusts base period income taxes to the level included in the forecasted test period. The effect of the adjustment on electric operations is a decrease in income tax expense of $3,197,364.

Q. PLEASE DESCRIBE SCHEDULE D-2.16.

A. Schedule D-2.16 is an adjustment to annualize revenue and fuel expense in the forecasted test period. The overall effect of the adjustment on pre-tax electric operations is to increase revenues in the forecasted test year by $284,270 and increase fuel expense by $114,499.

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

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

Q. PLEASE DESCRIBE SCHEDULE K.

A. Schedule K contains comparative financial and statistical information, as required by the Commission's filing requirements. I provided the forecasted plant data on page 1, the condensed income statement on page 2, the forecasted earnings per share on page 4, and the mix of sales and fuel on page 5, for the base period and the forecasted test period.

VI. <u>CONCLUSION</u>

Q. WAS THE INFORMATION YOU SPONSOR IN 16(6)(a), 16(6)(b), 16(6)(d), 16(6)(e), 16(7)(b), 16(7)(c), 16(7)(d), 16(7)(f), 16(7)(g), 16(7)(h), 16(7)(o), 16(8)(b), 16(8)(d), 16(8)(i), AND 16(8)(k), THE INFORMATION YOU PROVIDED TO MS. DANG FOR SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, SCHEDULES B-5 AND B-5.1, THE INFORMATION YOU PROVIDED TO MS. WEATHERSTON IN SUPPORT OF SCHEDULE B-8, SCHEDULES D-2.1 THRU D-2.16, AS WELL AS SCHEDULES I-1 THROUGH I-5, AND SCHEDULE K PREPARED BY OR SPONSORED AND SUPPORTED BY YOU?

A. Yes.

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

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Grady S. Carpenter III, Manager Financial Forecasting II, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Grady S. Carpenter III Affiant

Subscribed and sworn to before me by Grady S. Carpenter III on this 29 day of November, 2022.

Stephen R Smith
NOTARY PUBLIC
Cabarrus County, NC
My Commission Expires July 27, 2025

NOTARY PUBLIC

My Commission Expires: July 27, 2025

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

JACOB S. COLLEY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jacob S. Colley, and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Carolinas, LLC (DEC) as Director of Customer Services Strategy. DEC is a subsidiary of Duke Energy Corporation (Duke Energy) which provides various services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy.

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I obtained a bachelor's degree in Marketing Management from Virginia Tech's Pamplin College of Business in 2009. Upon graduation, I began my career in banking and finance and then shifted into a leadership role for a regional chamber of commerce and economic development organization. In 2016, I transitioned to the utility industry joining American Electric Power (AEP) where my roles included business development, economic development, community relations, and state government affairs for the Kentucky operations. I joined Duke Energy in 2018, having held roles within Stakeholder Engagement and Renewable Strategy and Policy, before assuming my current position in Customer Services in 2020.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF CUSTOMER SERVICES STRATEGY.

A. My responsibilities include oversight and execution of key customer initiatives, long-term strategic planning, regulatory compliance and reporting, and audit and compliance within Customer Services. I provide direction and leadership as business plans are developed to support the goal of increasing customer satisfaction.

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

A. No.

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

A. The purpose of my testimony is to highlight Duke Energy Kentucky's exceptional service to its customers and how that translates to customer satisfaction. I also describe some of the steps the Company is taking to further improve the experience and satisfaction of its customers when they engage with Duke Energy Kentucky. Finally, I sponsor the Company's formal cost support for the residential late payment charge as required in the most recent Duke Energy Kentucky order for Case No. 2021-00190.

II. OVERVIEW OF CUSTOMER SERVICES

Q. PLEASE DESCRIBE THE COMPANY'S CUSTOMER SERVICE GOAL.

A. One of the Company's primary goals is to provide excellent customer service. Duke Energy strives to exceed customer expectations by building genuine connections with all customers, soliciting customer feedback, taking note of evolving customer expectations, anticipating customer needs, leveraging emerging technologies, and offering dynamic solutions to customer issues. Customer service is a factor in the policies, programs, and decisions that the Company implements.

Q. PLEASE BRIEFLY DESCRIBE HOW THE COMPANY MEASURES EXCELLENCE IN CUSTOMER SERVICE?

A. The Company has implemented a comprehensive array of customer satisfaction measurement tools to understand and identify those aspects of the current customer experience that may cause difficulties or concerns for some customers. The Company's proprietary relationship study, CX Monitor, surveys customers to measure sentiment and satisfaction – both on an overall basis and with key experiences they have had with Duke Energy Kentucky over the past 12 months. Examples of these experiences include their billing and payment experience or use of the Company's web or phone channels. Customers provide a score for each experience they have had on a '0-10' scale as well as open-ended verbatim comments detailing the primary reason(s) for their score. The value of the CX Monitor over other surveys is that it asks our own customers about their perceptions, which can be compared against their actual experiences. Duke

Energy Kentucky has been able to leverage the data to generate insights, which has helped prioritize investment to drive customer satisfaction. The Company has also implemented Fastrack 2.0, a proprietary post-transaction measurement program. Fastrack 2.0 measures the quality of recent interactions customers have with the Company in near real-time, enabling the timely evaluation of the Company's customer performance.

Q. HOW DOES THE COMPANY UTILIZE ITS CUSTOMER CARE OPERATIONS TO SUPPORT ITS CUSTOMERS?

A. Our customer care operations are designed and continuously enhanced to ensure that all customer inquiries are answered promptly and accurately. Customer calls are either processed in the Interactive Voice Response (IVR) system, allowing customers to self-serve, or by a customer care specialist. There are around 300 Duke Energy and vendor customer care specialists that handle inbound and outbound calls, as well as emails, web inquiries, mailed letters, faxes and social media inquiries.

Also, the Company has the Duke Energy Social Media Customer Care program, which operates Monday through Friday from 8:00 a.m. to 5:00 p.m. assisting customers on the Duke Energy enterprise social media channels which consist of Facebook, Twitter, LinkedIn, and Instagram. Utilizing resources from the Consumer Affairs organization, employees assist customers in private, one-on-one conversations using direct messages to address any questions or issues that they may be having. The frequent inquiries received on social media are related to outages, billing, payment, and website questions.

Q. PLEASE DESCRIBE HOW DUKE ENERGY KENTUCKY'S SOCIAL MEDIA PROGRAM HAS EVOLVED TO KEEP PACE WITH CUSTOMERS' CHANGING EXPECTATIONS.

A. With the rise in the use of social media in recent years, Duke Energy Kentucky has seen an increased number of its customers contacting the Company for account-related questions through social media. The Duke Energy enterprise social media channels continue to grow, with more than 681,000 followers on its Facebook, Twitter, Instagram and LinkedIn pages as of October 2022. The Company uses these channels to inform customers about reliability updates in their area and changes that could impact their bill. Further, in an emergency or major storm, Duke Energy Kentucky uses social media to communicate important information to customers. Using social media allows the Company to proactively post warning and safety information to quickly reach as many customers and stakeholders as possible, engage with customers who have storm- or outage-related questions, and monitor how messages are being received and responded to. Moreover, the Company has posted updates, including videos detailing storm restoration progress and photos of significant damage to infrastructure, to show customers the scale of repairs underway.

III. <u>TRANSFORMING THE CUSTOMER EXPERIENCE</u>

Q. PLEASE DESCRIBE THE COMPANY'S EFFORTS TO ENHANCE CUSTOMER SATISFACTION.

A. Duke Energy Kentucky is working hard across the business to further improve the customer experience. The Customer Services organization is transforming the customer experience by making strategic, value-based investments for the benefit of customers with a focus on improving customer interactions with our customer care team and by enhancing communications and account management options via digital channels.

Q. HOW HAS DUKE ENERGY KENTUCKY MODERNIZED ITS PLATFORMS TO ENHANCE CAPABILITIES FOR CUSTOMERS?

A. The Company has made investments over the last couple years to leverage technologies and platforms enhancing our ability to engage with our customers. We successfully deployed a new Customer Information System (CIS), Customer Connect and a natural language IVR system, and we continue to effectively utilize Advanced Metering Infrastructure (AMI) and our digital channels to improve how customers interact with us.

Q. PLEASE DESCRIBE THE NEW CIS.

A. The Company recently deployed its new customer information system platform, Customer Connect. As further described by Company Witness Retha Hunsicker, this platform enables the Company to deliver a customer experience that simplifies, strengthens, and advances our ability to serve our customers. It provides a modern, configurable billing engine and is based on a customer-centric data model providing customers a more personalized experience. Customers are now able to take advantage of more automated processes and enhanced billing and payment options using new or enhanced self-service capabilities.

Q. PLEASE DISCUSS THE OTHER PLATFORM MODERNIZATIONS THAT ENHANCE ENGAGEMENT CAPABILITIES.

We recognize customers want to self-serve while navigating seamlessly through the IVR. Existing self-service functionality, such as requesting a payment arrangement and reporting a power outage, was improved via voice activated prompts. Newly added self-serve options allow customers the ability to enroll in, or withdraw from Budget Billing, add their card information to Speedpay Wallet for easy access, update their phone number and request their account number through the IVR. Another added feature, called First-in-Line, allows customers to either remain on hold or select a call back number where their place in line is reserved and a customer service representative can return their call.

With the capabilities now available through Customer Connect and the improved IVR, we can better connect with customers through texting experiences. Before, we were limited to sending web links to static forms that still required manual processing. The new capabilities allow for more dynamic URLs to process the requests reducing the need for intervention. For example, if a customer calls into the IVR for a start service request, we can offer to text them a link to the Start Service page, and if the customer prefers, they can complete their request from their device. Customers can also receive texts with additional options and links, such as bill reminders and confirmations, tree trimming information, payment locations, or street light repairs. And, we recently launched two-way texting allowing customers to respond to certain messages and reminders. For example, if a bill reminder is texted, and a customer responds saying they are not able to pay by the due date, the system can recognize that message and provide options or a link to set up an installment plan. These texting capabilities provide yet another avenue for customers to conveniently engage with us.

We have made key interaction options easier to locate online and made several enhancements to our digital and web-based offerings, including a planned vegetation management map, a feature alerting customers to estimated call wait times, the ability for customers to start and stop service online, a digital, self-service enrollment option for payment arrangements, and resources directing them to agency assistance support when needed. Since implementing these changes, customers are reporting higher satisfaction with their web experience and improved ease when completing tasks including "accessing their online account" and "requesting a payment arrangement."

Our free mobile app allows residential and small business customers to easily manage their account from anywhere in the U.S. The app was developed based on customers' most requested features – with it, customers can: view and pay their bill; use the app to manage their profiles; set reminders; schedule automatic payments; enroll in billing and payment programs or view their billing history; report an outage and receive restoration updates; monitor their energy use over time; and receive personalized offers that help them save. The app uses the same log-in as the customer's current account and has an option to use fingerprint or facial recognition for a fast, secure sign-in.

AMI meters continue to provide new options for customers. In combination with Customer Connect, the technology enabled Duke Energy

Kentucky to begin offering same-day start service in April 2022. Since then, approximately 4,500 residential customers have requested same-day service, which is approximately 29% of total start service requests. These enhancements have increased efficiency in operations and customer satisfaction.

Our Company's applications, digital channels, smart meters, mobile app and CIS allow us to offer various programs and products and to enhance how we engage with customers.

Q. HOW HAS THE COMPANY MADE IT EASIER FOR CUSTOMERS TO REPORT CONCERNS WITH SERVICE OUTAGES?

A. Outage reporting was enhanced to make it easier for customers through our website or mobile app. The Company launched a web form allowing customers to provide greater detail about their outage, along with an option to enter free form comments to provide more detail on the situation. The adoption rate of the new outage forms has grown across the enterprise with the success rate moving from approximately 55% with the legacy forms up to 87%. This change has helped equip the Company with more detail around the potential causes of outage. For example, a customer can report hearing a loud noise, which may point to a potential transformer failure. We continue to proactively communicate with customers experiencing outages by providing updates via text or email and deliver near real-time information through our new outage maps. Improvements were also made to the mobile app to ensure key outage data points were more visible to customers during active outages.

The Company has updated the "Ping It" program to enhance its usage by the Customer Care Operations and Customer Delivery teams. The ability to retrieve information such as voltage data or meter communication status helps troubleshoot customer issues more efficiently. The Ping It program continues to be especially useful during major storms.

A new Street and Area Light Repair platform was launched on the Company webpage in March 2021. This platform allows both customers and call center specialists to easily report streetlight issues. The tool enables reporting of details for the exact problem, improving operational efficiencies on repairs. Additionally, customers can select to receive email or text updates on the progress of their requested repair. Chartwell, a company that works with utilities to improve customer experience, satisfaction, and operational efficiency, recently awarded one of its 2022 Best Practices Awards in Outage Restoration to Duke Energy for this Street & Area Light Repair tool.

Q. WHAT STEPS IS THE COMPANY TAKING TO ENSURE EXCELLENT CUSTOMER SERVICE FOR ITS BUSINESS CUSTOMERS?

The Company established a new Business Service Center (BSC) focused on providing a more tailored service model customized by business segment for our SMB customers. By creating teams to serve each group, this new organization positions us to better understand and support the many different types of business customers we serve. This model allows us to build a virtual account management system to more effectively and efficiently handle requests and ensure customers are able to leverage all of our digital channels for their unique business needs.

The BSC will also allow us to expand assistance to additional builders, developers, and local inspecting authorities. By providing dedicated teams specializing in new construction, as well as a self-service Builder Portal, we can better serve this business segment of customers and provide options to better suit their needs. These teams will also serve our local inspecting authorities for processing inspections with customized solutions and points of contact to respond to their requests.

The BSC aligns teams that support builders, developers, and inspecting authorities, agriculture customers, multi-account customers, servicing for solar installations and billing, and all our business support functions under one organization.

IV. LOW-INCOME SUPPORT

Q. PLEASE DISCUSS HOW THE COMPANY SUPPORTS ITS LOW-INCOME CUSTOMERS IN KENTUCKY.

A. The Company continues to design, evaluate, and implement programs to help meet the needs of our customers. As mentioned by Witness Spiller, in 2021, Duke Energy launched its Share the Light Fund, a new brand with structure enhancements and a streamlined customer digital experience (formally WinterCare). Employees, customers, and Duke Energy shareholders contribute to the fund. The fund partners with and provides direct dollars to agencies in Kentucky to help qualifying customers pay their energy bills. Also the Home Energy Assistance Program (HEA) is an additional source of bill assistance to income-qualified customers. This program is funded through a combination of customer charges and shareholder contributions. The Community Action Kentucky and the Northern Kentucky Community Action Commission (NKCAC) administer the program. HEA supports customers during peak heating and cooling months with subsidy assistance credited to their account and the crisis assistance can support customers who have a past-due balance and are in danger of disconnection.

The Company offers energy savings programs to help its income-qualified customers through Payment Plus, Weatherization, and the Neighborhood Energy Saver Program (NES). For example, NES supports hundreds of homes in eligible neighborhoods each program year. Eligible customers can work with energy specialists who conduct a free walk-through energy assessment designed to educate customers about their electric use and ways to lower their bill. Customers can receive free energy-saving products at no cost, which include energy-efficient lightbulbs, AC/furnace filters, and water heater wraps. Additionally, as part of this rate case proceeding, the Company has proposed a new community solar program, Clean Energy Connection (CEC). CEC adds another income-qualified customer option while also providing these customers access to renewable energy. The program has a carve out that enables income-qualified customers to participate and see a net benefit immediately on their monthly bills. The details of the proposal are supported by Witness Halstead.

Finally, we realized that a more tailored experience was needed to serve our utility assistance agency partners more efficiently. Agencies provide one of the most critical channels for customers to receive support and assistance funding. Assistance agencies previously resolved questions or issues through the primary customer service line. To facilitate deeper relationships, we created a dedicated group called the Centralized Agency Support team. This team is a one-stop resource, with a unique telephone number and email address reserved exclusively for agencies that have questions or need support. This team is now a permanent fixture in the agency support model, and the Company anticipates this team will expand areas of support over time as it gains a deeper understanding of what agencies need most to assist our customers. In addition to the team, a new digital, self-service portal is available to provide agencies a confidential and secure way to view customer account details, process agency commitments, and make payments. Agencies can conveniently and more efficiently view pledge history on customer accounts to make more informed pledge decisions and receive notification of pledge expiration to ensure their commitments are satisfied.

V. LATE PAYMENT CHARGE FORMAL COST SUPPORT

Q. HAS THE COMPANY PROVIDED FORMAL COST SUPPORT FOR ITS RESIDENTIAL LATE PAYMENT CHARGE?

A. Yes. The Company has provided formal cost support for its residential late payment charge as required in the most recent Duke Energy Kentucky order in Case No. 2021-00190. A copy of this cost support is included as Attachment JSC-1 Formal Cost Support.

Q. PLEASE DESCRIBE THE FORMAL COST SUPPORT.

The formal cost support utilized historical customer payment data from March 2021 through February 2022 to determine the number of customers that triggered incremental credit and collection costs. The costs included were carrying costs of unpaid bills, outbound customer delinquency communications, and customer service costs (e.g., inbound calls for installment plans). To derive the recommended late payment charge percentage, the 12-month average for each cost was summed then divided by the average late paying residential customer's net monthly bill.

Q. PLEASE DESCRIBE THE PROPOSED CHANGES.

A. Duke Energy Kentucky proposes to reduce its customer late payment charge from 5 percent to 2.3 percent of the net monthly bill. The revised percentage more closely reflects the Company's current average of incremental costs related to late paying customers.

Q. HAS THE COMPANY REFLECTED THE RESULTS IN ITS PROPOSED TARIFFS?

A. Yes. The updated late charge is reflected in all the applicable tariff sheets supported by Company Witness Sailers.

VI. CONCLUSION

Q. WAS ATTACHMENT JSC-1 FORMAL COST SUPPORT PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR CONTROL?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Jacob S. Colley, Director Customer Services Strategy, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Jacob S. Colley

Jacob S. Colley Affiant

Subscribed and sworn to before me by Jacob S. Colley on this 22 day of Nov, 2022.

CECIL W. MANN JR. NOTARY PUBLIC MECKLENBURG COUNTY, N.C.

NOTARY PUBLIC

My Commission Expires: March 20, 2027

DUKE ENERGY KENTUCKY, INC.
Case No. 2022-00372

			Carrying Costs of Unpaid Bills		Delinquency Communcations		Call Customer Service Costs	
Month	# of Late paying Res Accounts	Avg Current Month Charges on Late Paying Accounts	Avg Current Month Past Due Balance	Avg Monthly Carrying cost per late paying acct	Accounts elgible for 10 Day written discconect for nonpayment notice	Average Comm cost per late paying acct	Estimated Total Call Handle Time (minutes)	Average call cost per late paying acct
3/1/2021	29,861	$ 115	$ 267	$ 1.21	8,650	$ 0.17	80,608	$ 2.48
4/1/2021	27,551	$ 91	$ 219	$ 1.00	8,089	$ 0.17	46,121	$ 1.54
5/1/2021	28,107	$ 74	$ 184	$ 0.83	6,968	$ 0.14	20,049	$ 0.66
6/1/2021	30,180	$ 75	$ 156	$ 0.71	6,714	$ 0.13	20,842	$ 0.64
7/1/2021	32,079	$ 97	$ 149	$ 0.68	6,464	$ 0.11	26,207	$ 0.75
8/1/2021	33,962	$ 120	$ 167	$ 0.76	7,889	$ 0.13	42,049	$ 1.14
9/1/2021	33,354	$ 116	$ 156	$ 0.71	7,942	$ 0.14	38,996	$ 1.08
10/1/2021	35,716	$ 115	$ 153	$ 0.69	8,237	$ 0.13	43,670	$ 1.12
11/1/2021	32,910	$ 83	$ 141	$ 0.64	8,220	$ 0.14	44,410	$ 1.24
12/1/2021	29,415	$ 89	$ 159	$ 0.72	7,006	$ 0.14	52,997	$ 1.66
1/1/2022	34,155	$ 123	$ 210	$ 0.95	7,487	$ 0.12	86,568	$ 2.33
2/1/2022	33,715	$ 164	$ 296	$ 1.35	10,126	$ 0.17	87,775	$ 2.40
	31,750	$ 105	$ 188	**$ 0.85**	7,816	**$ 0.14**	49,191	**$ 1.43**

Avg monthly cost per late paying acct: **$ 2.42**
% of avg late bill **2.30%**

Cost Category	Approximate Cost	Description
Communication	$0.57	10 day DNP notice, $.06 to produce and $.51 to mail
Phone cost/min	$0.92	Call Center Cost
Interest rate for carrying costs	5.45%	TVM Interest Rate

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

HUYEN C. DANG

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

December 1, 2022

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Huyen C. Dang and my business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

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

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I am a graduate of the University of North Carolina at Charlotte, with a Bachelor of Science degree in Accounting. I began my employment with Duke Energy in 1997 in the Financial Reporting group within the Accounting Department. I transferred to Asset Accounting in 2000 and transitioned to my current position within Asset Accounting in May 2022.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR OF ACCOUNTING.

A. As Director of Accounting, I have responsibility for accounting and reporting activities within Duke Energy's electric and natural gas utilities related to fixed assets, including electric plant in service, construction work in progress, and depreciation.

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

A. No.

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

A. I am responsible for actual net plant in service and construction work in progress contained in rate base and other actual plant-related items that Duke Energy Kentucky witness, Mr. Grady S. "Tripp" Carpenter uses in his testimony. I co-sponsor with Mr. Carpenter the following Schedules in satisfaction of Filing Requirements (FR) 16(8)(b): B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, and B-4. I sponsor Schedule D-2.24 in satisfaction of FR 16(6)(b) and FR 16(8)(d), as well as the actual plant data on Schedule K page 1, and the composite depreciation rates on Schedule K, both being in response to FR 16(8)(k). The source and sponsor of the budgeted and projected data as shown on these schedules is Mr. Carpenter. The source and sponsor of the proposed depreciation and amortization accrual rates used in these schedules, including the supporting depreciation study, is Company witness Mr. John J. Spanos.

II. SCHEDULES SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION CONTAINED IN THE SECTION B SCHEDULES.

A. The Section B schedules develop the Jurisdictional Net Plant in Service. The schedules are based on the Company's budget records as of the end of the base period (February 28, 2023) and the end of the forecast period (June 30, 2024).

Q. PLEASE DESCRIBE SCHEDULE B-2.

A. Schedule B-2 shows the plant in service including allocated common plant by major property grouping for the base period and the 13-month average as of the plant valuation date of June 30, 2024. The amount shown in the column labeled "Adjusted Jurisdiction" on page 1 of 2, and "13-Month Average Adjusted Jurisdiction" on page 2 of 2, represents plant in service that is deemed used and useful in providing electric service to our Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.1.

A. Schedule B-2.1 consists of a further breakdown of Schedule B-2 by the Federal Energy Regulatory Commission (FERC) and Company Account for each major property grouping for the base period and the forecast period. The plant in service investment shown in the column labeled "Adjusted Jurisdiction" on pages 1 through 6, and "13-Month Average Adjusted Jurisdiction" on pages 7 through 12, represents electric plant in service including allocated common plant that is deemed used and useful in providing electric service to the Company's Kentucky jurisdictional customers.

Q. PLEASE DESCRIBE SCHEDULE B-2.2.

A. Schedule B-2.2 shows proposed adjustments to plant in service for the base period and the forecast period. The adjustments shown on this schedule are related to ARO Balances, street lighting balances, and deferred depreciation related to the purchase of the DP&L share of East Bend. The adjustment for ARO is made to remove the ARO balances out of rate base for separate recovery. The lighting adjustments remove customer lighting balances that are recovered through separate tariffs from rate base.

Finally, the adjustment for the deferred depreciation related to the acquisition of DP&L's share of East Bend is related to the regulatory asset approved in Case 2015-00120. This adjustment adds this regulatory asset to rate base consistent with treatment approved in the Company's last base rate cases (Case 2017-00321 and 2019-00271). Each of these adjustments is shown as of the base period and is projected for the forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.3.

A. Schedule B-2.3 shows beginning and ending balances, as well as gross additions, retirements and transfers by FERC and Company Account for each major property grouping for the base period and the forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.4.

A. Schedule B-2.4 is entitled "Property Merged or Acquired" for the base period and the forecast period. Duke Energy Kentucky projects that no property will be merged or acquired during the base period or forecast period, so no items appear in this schedule.

Q. PLEASE DESCRIBE SCHEDULE B-2.5.

A. Schedule B-2.5 is entitled "Leased Property" and provides data for the base period and the forecast period. The Company does not project to have any assets under capital leases as of the base period or forecast period.

Q. PLEASE DESCRIBE SCHEDULE B-2.6.

A. Schedule B-2.6 shows the property held for future use included in rate base for the base period and forecast period. The Company has not included any property held for future use in rate base.

Q. PLEASE DESCRIBE SCHEDULE B-2.7.

A. Schedule B-2.7 contains data on utility property excluded from rate base for the base period and forecast period. There are no exclusions of utility property from rate base.

Q. PLEASE DESCRIBE SCHEDULE B-3.

A. Schedule B-3 shows the total plant investment and Reserve for Accumulated Depreciation and Amortization by FERC and Company Account grouping for the base period and the forecast period. The amounts for the forecast period on pages 7 through 12 are 13-month averages. The adjusted jurisdictional reserve in the last column is applicable to the jurisdictional plant shown on Schedule B-2, "Adjusted Jurisdiction" and "13-Month Average Adjusted Jurisdiction."

Q. PLEASE DESCRIBE SCHEDULE B-3.1.

A. Schedule B-3.1 shows adjustments to Accumulated Depreciation and Amortization for the base period and the forecast period. The adjustments shown on this schedule are the related accumulated depreciation balances for the adjustments to Plant in Service shown on Schedule B-2.2, which are described above.

Q. PLEASE DESCRIBE SCHEDULE B-3.2.

A. Schedule B-3.2 lists the 13-month average jurisdictional plant investment and reserve balance as of June 30, 2024 for each FERC and Company Account within each major property grouping. It also shows the proposed depreciation and amortization accrual rate, calculated annual depreciation and amortization expense, percentage of net salvage value, average service life and curve form, as applicable for each account. The calculated annual depreciation and amortization was determined by multiplying the 13-month average adjusted jurisdictional plant investment for the forecast period by the proposed depreciation and amortization accrual rates.

With this filing, the Company filed with the Commission proposed depreciation and amortization accrual rates prepared in 2022 and sponsored by Mr. Spanos of Gannett Fleming, Inc., who prepared the depreciation study. The account numbers referred to in the depreciation study were those in effect in 2022 for Duke Energy Kentucky. The Company requests that the Commission approve these new depreciation and amortization accrual rates included in this filing and that the depreciation and amortization accrual rates be effective July 1, 2023, corresponding with the effective date of the electric rates established in this case.

The amortization of the regulatory asset related to deferred depreciation for the Acquisition of DP&L's share of East Bend is the annual amortization amount approved in Case No. 2017-00321.

Q. PLEASE DESCRIBE SCHEDULE B-4.

A. Schedule B-4 is a list of Construction Work in Progress (CWIP) by major property grouping. The Company is not requesting to include recovery of CWIP in base rates.

Q. PLEASE DESCRIBE SCHEDULE D-2.24.

A. Schedule D-2.24 reflects the adjustment to the forecasted period depreciation expense to reflect annualized depreciation expense as calculated on Schedule B-3.2. Schedule B-3.2 shows annual depreciation on 13-month average plant balance at June 30, 2024, using the new proposed depreciation rates.

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN SCHEDULE K.

A. I sponsor the actual plant data submitted on page 1 of Schedule K. This information includes Plant in Service by major property grouping and Reserve for Accumulated Depreciation and Amortization by utility service for the 13-month average forecast period, for the base period and as of December 31 for each of the last ten years. Plant held for future use and construction work in progress have also been provided for the same periods. I also sponsor the composite depreciation rates shown on Schedule K.

Q. PLEASE DESCRIBE ANY AROS WITH POTENTIAL SETTLEMENT IN THE FUTURE.

A. Duke Energy Kentucky has AROs related to legal obligations for the following items: closure of the coal ash basin and the East and West landfills at East Bend, and removal of company-owned telecommunications assets from towers. Costs to close the coal ash basin and landfills at East Bend are ongoing and are being recovered or will be recovered through the ESM rider. The removal of the company-owned telecommunications assets from leased towers is projected to begin in 2023.

The telecommunications ARO is $0.3 million at June 30, 2022, and is supported by underlying cash flows of $0.4 million to remove telecommunication assets.

III. INFORMATION PROVIDED TO OTHER WITNESSES

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

A. Yes, I provided Mr. Carpenter with the actual net book value for the existing gas, electric, general, and common plant for the period ending August 31, 2022, for his use in calculating the forecasted financial data.

IV. CONCLUSION

Q. WERE SCHEDULES B-2, B-2.1, B-2.2, B-2.3, B-2.4, B-2.5, B-2.6, B-2.7, B-3, B-3.1, B-3.2, B-4, AND D-2.24, THE INFORMATION YOU PROVIDED ON SCHEDULE K, AND THE INFORMATION YOU PROVIDED TO MR. CARPENTER, (EXCLUDING THE BUDGET AND FORECAST NUMBERS PREPARED BY MR. CARPENTER AND THE PROPOSED DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND SUPPORTING DEPRECIATION STUDY PREPARED BY MR. SPANOS) PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Huyen C. Dang, Director of Accounting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Huyen C. Dang Affiant

Subscribed and sworn to before me by Huyen C. Dang on this 28 day of Nov., 2022.

VIRGINIA M. ADAMS
My Comm. Expires
NOTARY
PUBLIC
October 2, 2026
MECKLENBURG COUNTY, NC

NOTARY PUBLIC

My Commission Expires: 10/2/26

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

CORMACK C. GORDON

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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ATTACHMENTS:

Attachment CCG-1	MJ Bradley KY EV Analysis
Attachment CCG-2	Duke Energy Kentucky EV Forecast
Attachment CCG-3	Draft EVSE Tariff Non-Residential Terms & Conditions
Attachment CCG-4	Draft EVSE Tariff Residential Terms & Conditions

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Cormack C. Gordon and my business address is 1000 East Main Street, Plainfield, Indiana 46168.

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director Transportation Electrification. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree from the University of Tennessee and a Masters' degree in Management Science and Engineering from Stanford University. I have been employed by Duke Energy since September of 2010, and worked previously as an engineering consultant, in energy efficiency as an engineer, project manager and researcher, and as a general contractor. During my time at Duke Energy, I have worked in non-residential energy efficiency, including as a Products & Services Manager over programs in Kentucky. In 2014, I assumed responsibility for the Custom Incentives suite of programs & personnel across all of Duke Energy's territories. In 2020, after participating in several special projects related to electric transportation, I was asked to take on the role of Director, Products & Services to lead commercialization of electric vehicle infrastructure businesses. In May 2021, I assumed the role of Director, Transportation Electrification.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR TRANSPORTATION ELECTRIFICATION.

A. My responsibility as Director, Transportation Electrification is to lead the team that is accountable for executing electric transportation efforts in our various jurisdictions and for leveraging lessons learned and market trends to develop and implement new products, services and policies that enable customer adoption of electric transportation by identifying and solving for gaps in the electrification space. Members of my team are located throughout Duke Energy's service territories, including Kentucky.

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

A. No.

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

A. The purpose of my testimony is to describe the components of Duke Energy Kentucky's proposal to implement two new tariffs: 1) Electric Vehicle Site Make Ready Credit (Rate MRC); and 2) Electric Vehicle Service Equipment (Rate EVSE), (collectively the EV Programs) to assist Duke Energy Kentucky's customers desiring to make a transition to electric transportation. Specifically, I will provide details of each tariff, the benefits to customers, and the estimated cost for each program.

II. DISCUSSION

A. OVERVIEW OF THE COMPANY'S ELECTRIC VEHICLE (EV) STRATEGY AND NEED FOR A PROGRAM IN KENTUCKY

Q. PLEASE PROVIDE A BRIEF SUMMARY OF THE EV PROGRAMS AND TARIFFS THAT THE COMPANY IS PROPOSING IN THIS CASE.

A. The Company is proposing two electric vehicle (EV) programs and associated tariffs in this proceeding: (1) the Make Ready Credit (MRC) program and (2) the Electric Vehicle Supply Equipment (EVSE) program.

The MRC program will be available on a voluntary basis to residential and non-residential customers at their premise/places of business that require improvements (make ready infrastructure) to prepare for installation of a Level 2 or higher EV charger that is customer-owned or third-party owned. The Company will not own the make ready infrastructure. The credit is designed to defray installation costs associated with EV chargers to encourage mutually beneficial EV adoption.

The EVSE Program will be available on a voluntary basis and provides customers, both residential and non-residential, with the ability to choose a Level 2 or higher EVSE to have installed at their home or business. Once installed the customer would pay a flat rate each month for that charger for the life of the contract with the Company. Included in the monthly rate amount is the charger, installation and maintenance & warranty work for the charger during the duration of the contract. Duke Energy Kentucky will own the charging equipment, but customers will operate it on a day-to-day basis as per their unique needs. Participating customers will be responsible for any energy use (to be billed at standard, approved rates) as well as any make ready work that would be needed prior to installation.

Q. PLEASE EXPLAIN HOW ALL DUKE ENERGY KENTUCKY CUSTOMERS BENEFIT FROM THE ADVANCEMENT OF EV INFRASTRUCTURE AND EV ADOPTION?

A. Significant state-wide financial benefits are possible from increased EV adoption as shown in Attachment CCG-1. As incremental load is created through the implementation of broader public and private EV charging facilities, a broader base is created through which to spread utility costs. Thus, savings to all customers are anticipated to result from increasing EV adoption due to incremental net revenue received by selling electricity to charge EVs in excess of any increases in costs of service related to the additional load. As demonstrated in Attachment CCG-1, Figure 2, a net benefit to ratepayers of approximately $200 per EV is possible in 2030. Attachment CCG-2 provides the Company's EV adoption forecast for its Kentucky territory and shows that approximately 20,000 EVs are forecasted in Duke Energy Kentucky footprint by the end of 2030. At $200 per vehicle benefit, this provides savings to customers of nearly $4,000,000.

Simplifying the path to EV adoption and creating a connection with EV drivers that can be leveraged for future load management programs at scale in Kentucky is the pathway to realize these significant potential benefits.

Q. HOW WILL DUKE ENERGY KENTUCKY'S PROPOSED EV PROGRAM ADVANCE THE PATHWAY TO THESE BENEFITS?

A. The magnitude of change brought on by vehicle electrification requires a comprehensive and multi-faceted approach. The Company's plan focuses on two key aspects: 1) simplifying EV adoption for Kentucky customers; and 2) proactively readying the grid for growth from vehicle electrification.

For many customers the prospect of charging at the home is daunting. The installation of a 240-volt plug can be complex. In fact, many customers have likely never seen one. In addition, the selection and purchase of a 240-volt charger are potential barriers that may cause Kentucky customers to shy away from an EV purchase. The MRC and EVSE Tariff programs are specifically designed to allay these concerns.

Another barrier exists for multifamily dwellings. The benefits of home charging are a key driver in EV adoption, but this benefit is more challenging to achieve for multifamily dwelling customers. In designing the MRC and EVSE Tariff programs, one of the most important use cases the Company considered was service for apartment and condominium complexes. The program simplifies and makes the installation of EV charging equipment in parking lots more affordable.

Similar concerns exist for small and medium businesses with fleets of vehicles. Starting capital for the EV charging equipment and associated behind the meter make ready wiring are barriers to adoption. The MRC and EVSE programs provide options to address both.

Energy sales growth from vehicle electrification can be beneficial for Kentucky customers, but that growth must be actively managed to assure the greatest benefits for all customers. Managed charging is a term that encompasses multiple options for the utility to smooth charging load to reduce the need for infrastructure growth at all levels. The MRC and EVSE programs are foundational to managed charging. At the single-family home and multifamily level, where the majority of charging will occur, 240-volt charging is important to successful managed charging. Charging at 240 volts lends much greater flexibility than 120-volt charging, and this flexibility is key for successful managed charging. Additionally, the best time to market managed charging options is when customers are leveraging the MRC and EVSE programs to begin their electric vehicle transition. To that end, Company witness Mr. Bruce L. Sailers presents a residential time-of-use critical peak pricing rate that can provide customers with savings for managing the charging of their EVs and encourage those same customers to avoid on peak and especially critical peak hours when the electric system is most congested.

Large scale fleet electrification will affect Kentucky and the Company is preparing for that growth today. The Company believes that customers will benefit from this growth, but a proactive approach is required to assure the needs are met in the most cost-effective fashion. The MRC and EVSE programs can also be leveraged by large fleet customers in their EV transition, making Kentucky a preferred location for large delivery companies to start their conversions.

The Company will engage with stakeholders across the state to assess customer needs and build out these offerings, which will complement the MRC and EVSE programs.

Q. HAS DUKE ENERGY KENTUCKY OBTAINED UTILIZATION RATES FOR EV CHARGING IN THE COMMONWEALTH OF KENTUCKY?

A. No. Historically, 3rd party charging companies are not willing to readily share their proprietary usage data. However, the Company's proposed programs would allow Duke Energy Kentucky to measure utilization rates for various use cases without making presumption about where charging infrastructure is warranted. For the proposed programs, customers – not the Company – will make the decision to install EV charging infrastructure.

Q. PLEASE DESCRIBE THE CURRENT EV MARKET IN KENTUCKY AND WHAT IS CHANGING IN THE MARKETPLACE.

A. Attachment CCG-2 provides the Company's forecast for EV adoption in its Kentucky territory through 2030. Since the end of 2018, the number of EVs in that geography has nearly quadrupled. That value is expected to increase another 40+ percent by the end of 2023 and grow another eleven-fold by the end of 2030.

Accompanying this growth is federal funding from the Infrastructure Investment & Jobs Act (IIJA). Most immediately, IIJA creates the National Electric Vehicle Infrastructure (NEVI) program, under which Kentucky will receive allocated funding of approximately $70 million to create a foundational network of public DC fast charging locations along designated alternative fuel corridors and, potentially, public community charging in underserved areas across the

Commonwealth. The MRC and EVSE programs complement this funding. In addition to being available for private – not just public – charging use cases, the MRC can help to extend the impact of this federal funding. The EVSE tariff program will be available to the many important private charging use cases that enable EV use and that are not supported by IIJA.

Q. WHAT IS HAPPENING WITH RESPECT TO EV CHARGING IN THE UNITED STATES THAT HAS RELEVANCE FOR KENTUCKY?

A. The federal funding mentioned above is the Commonwealth's allocation of the total $5 billion in NEVI program dollars that will be invested over the next several years nationwide. That $5 billion in formula funding is accompanied by another $2.5 billion in total competitive grant funds for the same public charging use cases, another $5 billion in funding for clean metropolitan transit buses and $5 billion in funding for clean school buses.

Six districts in Kentucky have received approval for over $22 million to fund 56 buses. None of the districts are served by the Company, but in the event that future awards go to schools in the Company's footprint, an approved MRC program would help close a gap that remains – after federal funding – to procure & install charging infrastructure to serve an electric school bus.

The private sector is also making a strong push to electrify transportation. For example, Ford has announced its intention that over 40 percent of sales will have electric power trains by 2030. And, General Motors has said that it will offer only electric light duty vehicles by 2035.

Q. ARE THERE OTHER ELEMENTS OF FEDERAL ACTIVITY THAT DUKE ENERGY BELIEVES RELEVANT IN THIS PROCEEDING?

A. Yes. Section 40431 of the IIJA states, "Each State shall consider measures to promote greater electrification of the transportation sector, including the establishment of rates that—(A) promote affordable and equitable electric vehicle charging options for residential, commercial, and public electric vehicle charging infrastructure; (B) improve the customer experience associated with electric vehicle charging; (C) accelerate third party investment and; (D) appropriately recover the marginal costs of delivering electricity to electric vehicles and electric vehicle infrastructure." The Company's proposed MRC and EVSE tariff programs are consistent with this goal and certainly would further efforts in Kentucky to consider such measures as directed by the U.S. Congress.

Q. HOW ARE THE COMPANY'S MRC & EVSE TARIFF PROGRAMS CONSISTENT WITH THE GOALS OUTLINED IN THE IIJA?

A. The Company's proposed MRC program promotes affordable and equitable charging options by alleviating capital barriers via behind the meter funding for infrastructure to bring power to EV charging hardware. Further, the program provides for special allowance for multi-unit dwellings and Housing Authority buildings to increase access to EV charging for those that do not own their own single family home. The EVSE tariff also promotes affordable and equitable charging because it removes capital barriers by providing a "rental" structure and is configurable to a wide array of charging use cases, including multi-family dwellings.

These programs also improve the customer experience associated with EV charging. The MRC program provides residential customers with the Contractor Option wherein a Company-approved installer is assigned to install make ready infrastructure at the home, thus removing any barriers of consumer confidence in safe installation. Make ready infrastructure expenses include the cost of investments in the safe and reliable installation of wiring and other upgrades that support EV charging but exclude the cost of the equipment and charging station that directly supplies the energy to the EV. Both the MRC and EVSE programs provide for Level 2 or higher EV charging equipment installations. These types of chargers reduce charging times. Finally, the EVSE program removes maintenance burden and uncertainty associated with technology that is unfamiliar to consumers and businesses, helping to make more chargers available more of the time.

The MRC program also promotes third-party investment because it applies to all EV charging hardware ownership models and use cases while bringing down the cost of make ready infrastructure to a third party. For example, make ready credits can be applied both to electric transit bus scenarios as well as to DC fast charging installations operated by a third-party network but hosted on the property of a convenience store. Make Ready credits can even be coupled with federal funding brought about by IIJA. EVSE tariff allows for a wide array of manufacturers and model options, thereby encouraging – as opposed to limiting – participation by and competition among market players.

The Company plans to appropriately recover the costs for these new programs as is discussed by Company witness Sarah E. Lawler.

Q. WHAT TYPES OF CONSUMER PROTECTIONS DOES DUKE ENERGY KENTUCKY PROPOSE TO BUILD INTO ITS PROGRAMS?

A. The MRC Program has been designed to leverage the Company's experience with distribution system expansion and to work in a very similar way to the revenue credit offerings in the Company's Line Extension Policy (Rider X). The Company's successful Line Extension Policy has been in place for decades and currently, allows customers to potentially avoid out of pocket costs for extending lines to provide service up to value that equates to three times the estimated gross annual revenue for that customer's load. Customers whose cost to extend service is greater than the contemplated three-year or less payback period, must pay a contribution in aid of construction to extend service and/or agree to a minimum bill for a period of years. This approach benefits new and existing customers by connecting the per unit cost of electricity to investment in grid infrastructure. Based on the success of this longstanding policy, the MRC Program design follows the Company's Line Extension Policy as closely as possible. Specifically, the Program provides credits based on increased revenue from EV charging for the first three years after an installation, just as the Line Extension Policy provides a revenue-based credit over the same time frame where infrastructure enables a customer to join the system.

Since the EVSE program is a separate tariffed offering, non-participating customers will not pay for this tariff. As designed, the MRC Program and EVSE programs will encourage residential and non-residential customers to invest in working upgrades to existing structures while also delivering a benefit to all utility customers by lowering the per unit cost of electricity associated with new electric vehicle charging load.

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S PROPOSED EV PROGRAM IS DIFFERENT FROM OTHER KENTUCKY UTILITY-INITIATED EV PROGRAMS.

A. Duke Energy Kentucky is aware of the current programs offered by Louisville Gas & Electric (LG&E) and the Kentucky Utilities (KU). LG&E and KU's Electric Vehicle Program currently offers two non-residential options for Level 2 EV charging.[1] Option EVSE (Electric Vehicle Supply Equipment) enables the utility to install, own, and maintain a level 2 charging station for a monthly service fee that the customer pays over a 5-year agreement. Option EVC (Electric Vehicle Charging) enables the utility to install, own, and maintain up to twenty level 2 charging stations where EV drivers pay to charge their vehicles.

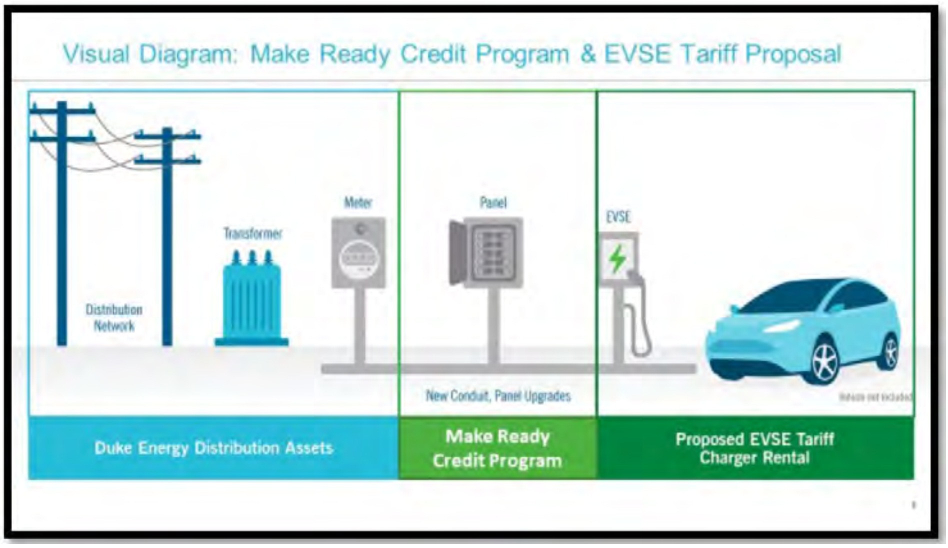
Currently available utility programs in Kentucky do not include ownership model agnostic funding for customers to install EV charging stations as is provided by the MRC program.

While similar to the LG&E-KU program in structure, the EVSE Tariff will provide more customer hardware options with multiple residential and commercial level two charging stations, as well as several different commercial fast charging options at various power output levels. The participating customer will have multiple network options to choose from as well. The Tariff gives the customer full autonomy

[1] LG&E and KU electric vehicle charging. Accessible by https://lge-ku.com/environmental/environment/alternate-fuels-road/ev/charging and Kentucky Public Service Commission in Case Nos. 2018-00295 dated April 30, 2019, and 2015-00355, dated April 11, 2016.

to operate and set pricing on their leased stations.

The diagram below provides a visual depiction of how the two programs build upon Commission-approved line extension policies to help customers complete the infrastructure stack required for EV charging.



B. <u>OVERVIEW OF THE RATE MRC TARIFF AND PROGRAM</u>

Q. PLEASE MORE FULLY DESCRIBE THE MRC PROGRAM AND TARIFF.

A. As I previously described, the MRC program will be available on a voluntary basis to residential and non-residential customers at their premise/places of business that require improvements (make ready infrastructure) to prepare for installation of a Level 2 or higher EV charging equipment that is customer-owned or third-party owned. The Company will not own the make ready infrastructure. The credit is designed to defray installation costs associated with EV chargers to encourage mutually beneficial EV adoption. The Customer must be an electric customer of the Company at a location on the Company's electric distribution system. Each Level 2 and Level 3 (DC Fast Charging) station installed at the customer's premise must feature at least one charging plug meeting all applicable safety and reliability standards – such as certification from a nationally recognized testing laboratory – for the given charging level. The work to install make ready infrastructure must be performed by a licensed electrician or a business employing licensed electricians (Contractor).

Q. PLEASE EXPLAIN THE RESIDENTIAL CREDIT UNDER THE PROGRAM.

A. A residential customer may receive revenue credits for make ready infrastructure either through a reduction in the price charged by a Contractor that has been approved by the Company (Contractor Credit Option) or through a direct application submitted to the Company by the customer (Customer Credit Option). Revenue credits for residential customers are akin to the Company's line extension policy and will not exceed the estimate of the aggregate increase in electric revenue for the first three years following installation of newly-installed charger.

The customer must submit an application with the Company requesting participation in this program. The application will require the customer to provide, among other information:

1. Detailed invoice(s) from the contractor for make ready infrastructure. Each invoice from the contractor must include separate line items for labor and materials and the contractor's name, address, and telephone number;
2. A copy of the approved permit from the municipal or local permitting authority; and

3. Evidence of EV registration.

The sum of the costs for make ready infrastructure stated in the invoice(s) submitted with the application are considered the "Demonstrated Costs" subject to revenue crediting; provided, however, that "Demonstrated Costs" shall not include any amounts for which the customer expects coverage or reimbursement from a third-party funding source. It is not the intention of this Program to provide revenue credits to defray expenses for which the customer expects third-party funding. To be eligible for revenue credits under this Program, the application must be submitted within 120 days following the later of:

1. The date on the most recent invoice included with the application; or
2. The date of EV registration.

After the Company receives and reviews an application for completeness, including but not limited to the submission of items 1-3 listed above, as applicable, the Company will, subject to the terms and conditions of this program, provide make ready infrastructure revenue credits to the customer.

Q. PLEASE EXPLAIN THE NON-RESIDENTIAL MRC CREDIT.

A. The customer must submit an application with the Company requesting participation in this program. The application will require the customer to provide, among other information:

1. Detailed invoice(s) from the contractor for make ready infrastructure. Each invoice from the contractor must include

separate line items for labor and materials and the contractor's name, address, and telephone number;

2. For all installations involving installation of more than one charging station or Level 3 or higher charging station, a schematic diagram of the installation;

3. A copy of the approved permit from the municipal or local permitting authority; and

4. A completed customer usage profile form.

The application must be submitted within 120 days following the later of:

1. The date on the most recent invoice included with the application; or

2. The date listed on the approved permit.

The sum of the costs for make ready infrastructure stated in the invoice(s) submitted with the application are considered the "Demonstrated Costs" subject to revenue crediting; provided, however, that "Demonstrated Costs" shall not include any amounts for which the customer expects coverage or reimbursement from a third-party funding source. It is not the intention of this Program to provide revenue credits to defray expenses for which the customer expects third-party funding. The customer must acknowledge that a Company representative may, with reasonable advance notice, access the customer's charging station installation to verify compliance with the terms of this program.

After the Company receives and reviews an application for completeness, including but not limited to the submission of items 1-4 listed above, as applicable, the Company will, subject to the terms and conditions of this program, provide make ready infrastructure revenue credits to the customer in accordance with the following standards:

For non-residential customer applicants, other than multi-family dwellings and housing authorities, the Company will determine a make ready infrastructure revenue credit amount based on the completed customer usage profile form and the expected increase in revenue to be achieved through such usage for the first three years of operation, with the revenue credits not to exceed the Demonstrated Costs; provided, however, that for such a non-residential customer that is simultaneously participating in the Company's Line Extension Policy and eligible for revenue credits under such policy that account for the anticipated EV charging load, the Company will develop a make ready infrastructure revenue credit amount based on the completed customer usage profile form and the expected increase in revenue to be achieved through such usage for the first year following installation, with the make ready infrastructure revenue credits not to exceed the Demonstrated Costs.

Where an application involves installation of multiple EV chargers, the expected increase in revenue will be determined for each charger for the applicable number of years stated above and summed, and this sum will be compared to the Demonstrated Costs. The revenue credits for such application are to be based on such sum of the expected increase in revenue from the multiple chargers but are not to exceed the Demonstrated Costs.

Q. PLEASE EXPLAIN THE MULTI-FAMILY DWELLINGS AND HOUSING AUTHORITIES MRC CREDIT.

A. For a non-residential customer applicant that is an owner or property manager of a building or complex with four or more housing units (Multi-Family Dwelling or MFD), or a public entity that provides housing targeted toward low-income and moderate-income residents that is seeking to provide EV charging access to a property or properties that contains four or more housing units (Housing Authority), and where the customer demonstrates that all charging stations will be accessible to residents of the MFD or Housing Authority and installed for the primary use of such residents, the Company will determine a make ready infrastructure revenue credit amount based on the completed customer usage profile form and the expected increase in revenue to be achieved through such usage for the first three years of operation, with the revenue credits not to exceed the Demonstrated Costs; provided, however, that for such a non-residential customer that is simultaneously participating in the Company's Line Extension Policy and eligible for revenue credits under such program that account for the anticipated EV charging load, the Company will develop a make ready infrastructure revenue credit amount based on the completed customer usage profile form and the expected increase in revenue to be achieved through such usage for the first two years following installation, with the Make Ready credits not to exceed the Demonstrated Costs.

Q. PLEASE EXPLAIN THE CONTRACTOR CREDIT OPTION.

A. Under the Contractor Credit Option, a residential customer seeking installation of a qualifying charging station and make ready infrastructure at the customer's premises selects a contractor that has been approved by the Company for participation in this program. A list of such approved contractors will be available on the Company's website. The contractor must contact the Company to determine the customer's make ready infrastructure revenue credit based on information provided by the customer. The contractor is then responsible for including the make ready infrastructure revenue credits in the price quoted to the customer for make ready infrastructure installation. The customer is responsible for providing the contractor and/or third-party vendor with evidence of EV registration.

After the Company receives and reviews an application for completeness, the Company will, subject to the terms and conditions of this program, provide make ready infrastructure revenue credits to the contractor.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING RATE MRC IN THIS CASE?

A. The program simplifies adoption of EVs and charging by customers through revenue credits that defray a portion of EV "make ready" expenses. The program also provides fixed incentives to approved homebuilders installing make ready infrastructure into newly constructed homes. Finally, with emphasis on its Contractor Credit Option, the program provides for the safe installation of make ready infrastructure for residential customers that may lack comfort with higher voltage installations.

Q. WHAT IS THE ESTIMATED AMOUNT OF CREDIT AVAILABLE FOR CUSTOMERS TAKING SERVICE UNDER RATE MRC?

A. The table below provides the anticipated credits available under the program.

Segment	Credit Amount
Public L2 Charger	$ 918
Workplace L2 Charger	$ 3,211
Fleet Level L2 Charger	$ 5,885
Public DCFC	$ 16,434
School Bus - DCFC	$ 20,855
Transit Bus - DCFC	$ 37,692
> 50 kW DCFC or total number of chargers exceeding 50 kW of demand - Calculated per job	
Multi-Family Dwelling Segment	**Credit Amount**
Multi-Family L2 Charger	$ 918
Multi-Family DCFC	$ 16,434
> 50 kW DCFC or total number of chargers exceeding 50 kW of demand - Calculated per job	
Residential Segment	**Credit Amount**
Residential	$ 870
* Customers that are simultaneously participating in Line Extension Plan receive 1/3 the credit amount listed with the exception of multi-family dwellings and Housing Authority locations, which receive 2/3 the credit amount.	

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY HAS CALCULATED THE MRC RATE CREDITS?

A. The foundation of make ready credits are the consumption and demand expected from EV charging installations. The Company has leveraged data collected from pilot programs in its sister utilities as the basis of consumption and demand assumptions. As I mentioned previously in my testimony, the Company used the existing calculation methodology it uses in its Line Extension Policy to calculate the credits.

Q. HOW IS DUKE ENERGY KENTUCKY PROPOSING TO RECOVER THE COSTS OF THIS CREDIT?

A. The Company is requesting that the costs be deferred as a regulatory asset for recovery in a future proceeding. Company witnesses Ms. Lawler and Ms. Danielle L. Weatherston discuss this in further detail.

Q. IS DUKE ENERGY KENTUCKY PROPOSING ANY PARAMETERS TO CONTROL THE COSTS OF THE MRC PROGRAM?

A. Yes, there are per charger upper limits on credit amounts paid. These upper limits include both the revenue calculation described above and the customer's demonstrated cost of installing make ready infrastructure. Demonstrated costs, in turn, may not include only physical upgrades necessary to bring power to a charger location on the customer side of the meter. Demonstrated costs may not include permits, installation of the EV charger, or the charger itself.

Based on these parameters and program participation estimates, annual program costs for the next several years (through 2026 calendar year) are estimated to average less than $1.1 million and reach $1.7 million in 2026 as more and more customers look to transition to an EV and seek simplifying solutions to do so.

Q. DO ANY OF DUKE ENERGY KENTUCKY'S SISTER UTILITIES HAVE A SIMILAR MRC PROGRAM?

A. Yes, the MRC program is currently approved and being implemented in Duke Energy Carolinas North Carolina and Duke Energy Progress North Carolina.

Q. WHAT IS THE PARTICIPATION RATE OF THOSE PROGRAMS?

A. As of November 2022, Duke Energy Carolina and Duke Energy Progress collectively have received 331 applications with 128 customer participants for the Customer Credit Option. The Contractor Credit Option has resulted in 128 applications, with 21 customers who are participants. One non-residential participant and zero homebuilder applications have been received.

Q. HAS DUKE ENERGY KENTUCKY APPLIED LEARNINGS FROM THOSE OTHER MRC PROGRAMS FOR ITS OWN MRC PROGRAM? PLEASE EXPLAIN.

A. The program has been live for approximately six months as of the time of this filing. As a result, no major structural improvements have been made to date. There have been refinements to customer-facing websites for information such as program details, participation requirements and application instructions. Continuous improvement is occurring with a focus on the customer to ensure a seamless experience.

A benefit of the Company's ties to other jurisdictions is that the Company would desire to proactively bring learnings and improvements to the Kentucky offering for both customer and Company benefit.

Q. DOES DUKE ENERGY KENTUCKY BELIEVE A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN) IS REQUIRED FOR THIS PROGRAM?

A. No. Duke Energy Kentucky is not proposing to construct any of the charging infrastructure. Rather, the MRC is intended to help customers cover the costs of any Company infrastructure upgrades or rearrangements required to accommodate the customer's charging infrastructure. The Company's system changes are akin to ordinary extensions in the usual course of business.

C. OVERVIEW OF RATE EVSE TARIFF AND PROGRAM

Q. PLEASE DESCRIBE THE EVSE PROGRAM AND RATE EVSE TARIFF.

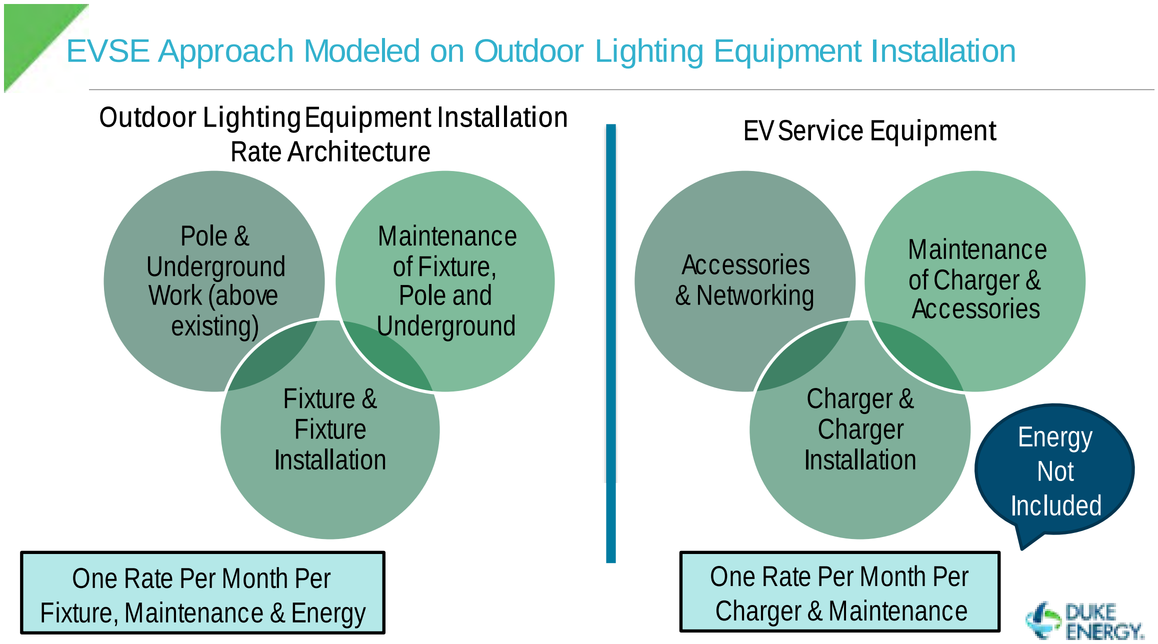
A. This Program is available on a voluntary basis and provides both residential and non-residential customers with the ability to choose a Level 2 or higher EVSE to have installed at their home or business. Once installed the customer would pay a flat rate each month for that charger. Included in the monthly rate amount is the charger, installation and any maintenance warranty item for the charger during the duration of the contract. Duke Energy Kentucky will own the charging equipment, but it will not be placed into rate base. The equipment will be paid for by the customer voluntarily taking service under the tariff over time. Participating customers will be responsible for any energy use (to be billed at standard, approved rates) as well as any make ready work that would be needed prior to installation.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING AN EVSE TARIFF IN THIS CASE?

A. The EVSE Tariff program provides a service to participants that will remove barriers to EV adoption by reducing both the upfront costs and the uncertainty associated with new technologies and maintenance of those technologies. Once installed, the charging stations will be customer operated. The program offers customers a worry-free, affordably-priced charger rental service where Duke Energy Kentucky owns, manages, and maintains the equipment through its lifetime, including replacements as needed while also allowing customers full autonomy in operating their charging systems with such decisions as access control and user pricing left up to the participating customer. In sum, the EVSE program is for customers that do not want the responsibility for purchasing and maintaining EVSE for themselves and who are interested in minimizing their upfront expense.

Q. PLEASE DESCRIBE THE EVSE PROGRAM AND TARIFF IN FURTHER DETAIL.

A. The EVSE Tariff Program is similar in structure to the Company's outdoor lighting programs under Sheet No. 63, Rate OL-E, Outdoor Lighting Equipment Installation, as shown in the diagram below. The Company's outdoor lighting program receives separate treatment and have unique costs to serve. Company witness Ms. Lawler explains this in more detail in her testimony. The Company's outdoor lighting programs allow for low up-front cost and an all-in rate, which makes lighting simple and affordable for customers. Similarly, the EVSE Tariff Program allows for low up-front cost, which helps to make EVSE installation affordable for customers. Additionally, like outdoor lighting offerings, the EVSE Program allows for multiple vendor options and a wide project selection.



Q. WHO IS ELIGIBLE FOR SERVICE UNDER RATE EVSE?

A. The Customer must be an electric customer of the Company at a location on the Company's electric distribution system.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING RATE EVSE IN THIS CASE?

A. The EVSE Program supports adoption of EVs and EV charging by providing customers with a trusted solution for EV charging that removes hurdles such as capital and the hassle and uncertainty of maintenance. Duke Energy Kentucky will provide customers with installation and maintenance in exchange for one flat rate charge each month. EVSE expenses include the cost of investment in safe and reliable chargers, installation, and maintenance or warranty service. Expenses exclude wiring and other upgrades that support EV charging (make ready infrastructure) as well as the energy the charger consumes.

Q. WHAT ARE THE COMPANY'S TERMS AND CONDITIONS FOR TAKING SERVICE UNDER RATE EVSE?

A. Please refer to attachments CCG-3 and CCG-4.

Q. PLEASE EXPLAIN HOW DUKE ENERGY KENTUCKY HAS CALCULATED THE EVSE RATES?

A. An explanation of the calculation of EVSE monthly fees is provided in the testimony of Company witness Mr. Sailers.

Q. HOW IS DUKE ENERGY KENTUCKY PROPOSING TO RECOVER THE COSTS OF RATE EVSE?

A. The proposed recovery for costs of Rate EVSE is provided in the testimony of Company witness Ms. Lawler.

Q. IS DUKE ENERGY KENTUCKY PROPOSING ANY PARAMETERS TO CONTROL THE COSTS OF THE EVSE PROGRAM?

A. Yes, The Company will leverage vendor contracts and program policies to control costs to purchase, install and maintain chargers. Additionally, the program is voluntary for customers to participate and will not impact non-participating rate payers.

Q. DO ANY OF DUKE ENERGY KENTUCKY'S SISTER UTILITIES HAVE A SIMILAR EVSE PROGRAM?

A. Yes, the EVSE Tariff program in Duke Energy Indiana was approved June 1, 2022, and will launch in the fourth quarter of 2022. Key aspects of that program, as well as similar programs in other areas beyond Kentucky are included in the table below.

Program Name	Evolution Home Coming November 2022	Accelerate at Home	Charger Solution
Example Market	Florida	Minnesota	Indiana
Program Basics	"With the new FPL EVolution Home, a residential charging program, we will permit, install and maintain a Level 2 charger and the required 240-volt circuit in your garage for a faster and convenient charging experience. No upfront cost for equipment or installation. Just plug in and forget it – chargers will be programmed to automatically start charging so you can enjoy the benefits of unlimited weeknights and weekend off-peak charging, all for one low monthly cost."	Rent or Purchase options that automatically uses Off Peak Charging	Charger Rental program – monthly flat fee includes installation, maintenance and warranty. Choose from a variety of charging hardware from multiple providers.
Customer Type	Residential	Residential	Residential and Commercial Customers
Charger Type	L2	L2	L2 and DCFC
Includes Make Ready or Off Peak Charging?	Off Peak Charging Required and Option for Make Ready in Full Install offer	Off Peak Charging required	No
Charger Hardware Providers	Not yet publicly available	Charge Point Home Flex Enel X Juice box	Various

Q. WHAT IS THE PARTICIPATION RATE OF THOSE PROGRAMS?

A. With the launch of the program in Indiana still pending at this time, there is no participation to date.

Q. HAS DUKE ENERGY KENTUCKY APPLIED LEARNINGS FROM THOSE OTHER EVSE PROGRAMS FOR ITS OWN EVSE PROGRAM? PLEASE EXPLAIN.

A. With the program pending launch, there have been no major learnings to date that have impacted the development of the Kentucky EVSE Program proposal.

Because the programs are jointly managed across state lines by Duke Energy personnel, any on-going learnings will be incorporated as they are realized.

Q. DOES DUKE ENERGY KENTUCKY BELIEVE A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY (CPCN) IS REQUIRED FOR THIS PROGRAM?

A. No. The EVSE Program will instruct and require the customer to install their "make-ready," or "premise wiring" charging infrastructure to accommodate a safe and reliable installation of the Company's charging station equipment. Any customer site electric service upgrades required will follow ordinary line extensions in the usual course of business. There is no duplication of facilities. The cost of an EVSE station is not significant and will not impact the Company's existing financial condition. The EVSE program is only offered to customers located in the Company's certified service territory and it will not interfere with any other electric utility's service.

Q. WHAT IS THE ESTIMATED ANNUAL COST OF THE EVSE PROGRAM?

A. The fixed annual cost of the EVSE Tariff program is currently estimated to be $75,000. This operational cost includes program platform fees, preventative and corrective maintenance, marketing, and general and administrative labor, both internally and externally. Variable costs of the program include hardware, software and installation costs and are a function of actual realized participation in the various chargers the Company proposes to provide.

III. CONCLUSION

Q. WERE ATTACHMENTS CCG-1 THROUGH 4 PREPARED OR ASSEMBLED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF INDIANA)
) SS:
COUNTY OF HENDRICKS)

The undersigned, Cormack C. Gordon, Director Transportation Electrification, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that it is true and correct to the best of his knowledge, information and belief.

Cormack C. Gordon Affiant

Subscribed and sworn to before me by Cormack C. Gordon on this 18 day of NOVEMBER, 2022.

Zacharia Glenn
NOTARY PUBLIC

ZACHARIA GLENN
Marion County
Commission Number NP0729900
My Commission Expires
December 12, 2028

My Commission Expires: 12-12-2028

Electric Vehicle Cost-Benefit Analysis

Plug-in Electric Vehicle Cost-Benefit Analysis: Kentucky

MJB & A

June 2018

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About M.J. Bradley & Associates

M.J. Bradley & Associates, LLC (MJB&A), founded in 1994, is a strategic consulting firm focused on energy and environmental issues. The firm includes a multi-disciplinary team of experts with backgrounds in economics, law, engineering, and policy. The company works with private companies, public agencies, and non-profit organizations to understand and evaluate environmental regulations and policy, facilitate multi-stakeholder initiatives, shape business strategies, and deploy clean energy technologies.

Our multi-national client base includes electric and natural gas utilities, major transportation fleet operators, clean technology firms, environmental groups and government agencies.

We bring insights to executives, operating managers, and advocates. We help you find opportunity in environmental markets, anticipate and respond smartly to changes in administrative law and policy at federal and state levels. We emphasize both vision and implementation, and offer timely access to information along with ideas for using it to the best advantage.

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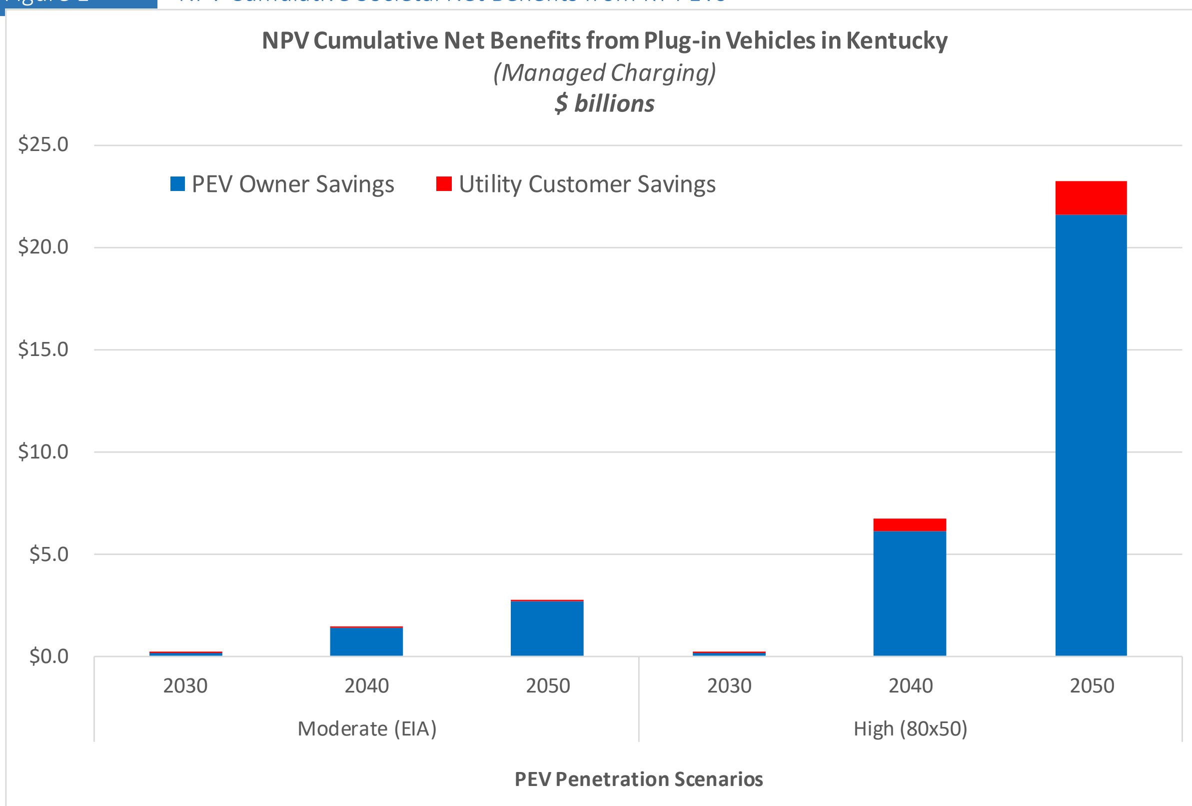
Executive Summary

This study estimated the costs and benefits of increased adoption of plug-in electric vehicles (PEVs) in the state of Kentucky. The study estimated the financial benefits that would accrue to all electric utility customers in Kentucky due to greater utilization of the electric grid during low load hours and resulting increased utility revenues from PEV charging. In addition, the study estimated the annual financial benefits to Kentucky drivers from owning PEVs—from fuel and maintenance cost savings compared to owning gasoline vehicles. The study also estimated reductions in gasoline consumption, and associated greenhouse gas (GHG) and nitrogen oxide (NOx) emission reductions from greater use of PEVs instead of gasoline vehicles.

Figure 1 NPV Cumulative Societal Net Benefits from KY PEVs



This study evaluated PEV costs and benefits for two distinct levels of PEV adoption – essentially a "business as usual" scenario of modest PEV penetration (EIA), and a much more aggressive scenario based on the PEV penetration that would be required to get the state onto a trajectory to reduce light-duty GHG emissions by 70 – 80 percent from current levels by 2050 (80x50). The levels of PEV penetration in the high 80x50 scenario are unlikely to be achieved without aggressive policy action at the state and local level, to incentivize individuals to purchase PEVs, and to support the necessary roll-out of PEV charging infrastructure.

As shown in Figure 1, if Kentucky PEV adoption follows the moderate trajectory currently assumed by the Energy Information Administration (EIA), the net present value of **cumulative net benefits from greater PEV use in the state will exceed $2.8 billion state-wide by 2050**.[1] Of these total net benefits:

[1] Using a 3% discount rate

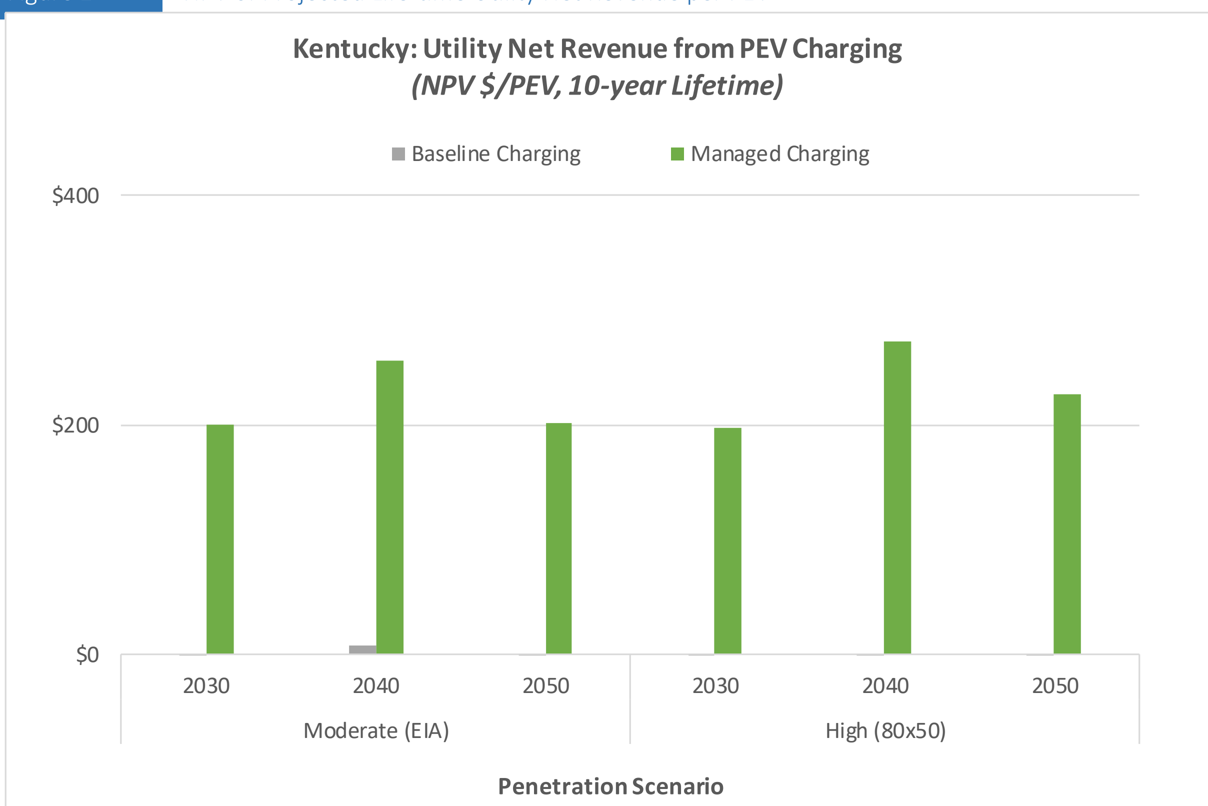
- $0.1 billion will accrue to electric utility customers in the form of reduced electric bills, and
- $2.7 billion will accrue directly to Kentucky drivers in the form of reduced annual vehicle operating costs.

Also shown in Figure 1, if PEV sales in Kentucky were high enough to get the state onto a trajectory to reduce light-duty GHG emissions by 70 – 80 percent from current levels by 2050 (80x50), the net present value of **cumulative net benefits from greater PEV use in Kentucky could exceed $23.2 billion state-wide by 2050**. Of these total net benefits:

- $1.6 billion would accrue to electric utility customers in the form of reduced electric bills, and
- $21.6 billion would accrue directly to Kentucky drivers in the form of reduced annual vehicle operating costs.

Utility customer savings result from net revenue received by the state's utilities, from selling electricity to charge PEVs. This net revenue is net of additional costs that would be incurred by utilities to secure additional generating capacity, and to upgrade distribution systems, to handle the incremental load from PEV charging. The NPV of projected life-time utility net revenue per PEV is shown in Figure 2. Assuming a ten-year life, the average PEV in Kentucky in 2030 is projected to increase utility net revenue by about $199 over its life-time, if charging is managed. PEVs in service in 2050 are projected to increase utility net revenue on average by about $214 over their life time (NPV) if charging is managed.

Figure 2 NPV of Projected Life-time Utility Net Revenue per PEV



In addition, by 2050 PEV owners are projected to save more than $1,050 per vehicle (nominal $) in annual operating costs, compared to owning gasoline vehicles. A large portion of this direct financial benefit to Kentucky drivers derives from reduced gasoline use—from purchase of lower cost, regionally produced electricity instead of gasoline imported to the state. Under the Moderate PEV (EIA) scenario, PEVs will reduce cumulative gasoline use in the state by more than 0.8 billion gallons through 2050 – this cumulative gasoline savings grows to 9.9 billion gallons through 2050 under the high PEV (80x50) scenario. In 2050, annual average gasoline savings will be approximately 126 gallons per PEV under the Moderate PEV (EIA) scenario, while projected savings under the High PEV (80x50) scenario are nearly 165 gallons per PEV.

This projected gasoline savings will help to promote energy security and independence, and will keep more of vehicle owners' money in the local economy, thus generating even greater economic impact. Studies in other states have shown that the switch to PEVs can generate up to $570,000 in additional economic impact for every million dollars of direct savings, resulting in up to 25 additional jobs in the local economy for every 1,000 PEVs in the fleet [1].

In addition, this reduction in gasoline use will reduce cumulative net GHG emissions by over 8.5 million metric tons[2] through 2050 under the moderate PEV scenario, and over 103 million metric tons under the high PEV scenario. The switch from gasoline vehicles to PEVs is also projected to reduce annual NOx emissions in the state by over 240 tons in 2050 under the moderate PEV (EIA) scenario, and by over 3,740 tons under the high PEV (80x50) scenario.

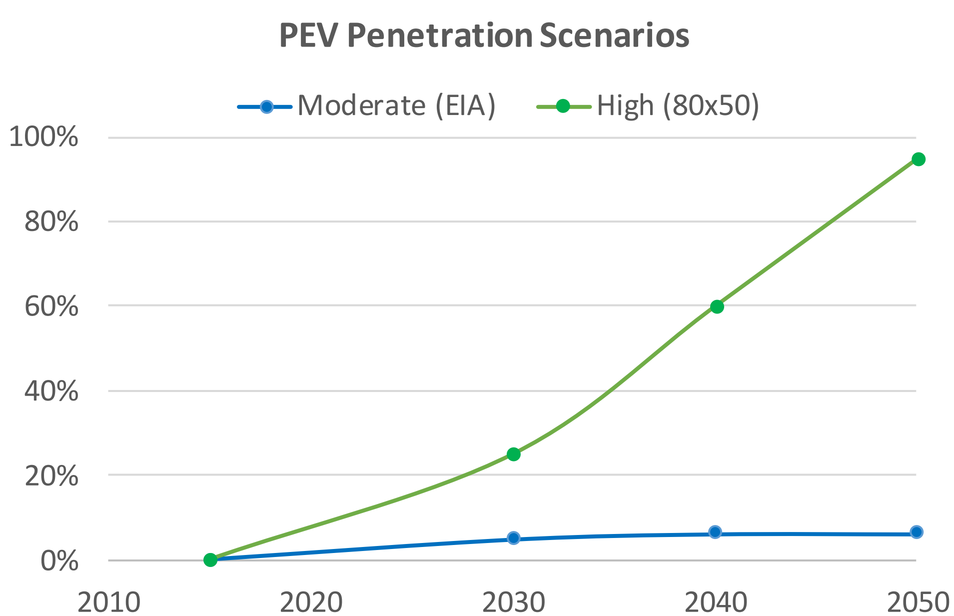
[2] Net of emissions from electricity generation

Study Results

This section summarizes the results of this study, including: the projected number of PEVs; electricity use and load from PEV charging; projected gasoline savings and GHG reductions compared to continued use of gasoline vehicles; financial benefits to utility customers from increased electricity sales; and projected financial benefits to Kentucky drivers compared to owning gasoline vehicles. All costs and financial benefits are presented as net present value (NPV), using a 3 percent discount rate.

Two different PEV penetration levels between 2030 and 2050 are utilized to estimate costs and benefits.[3] The "Moderate PEV" scenario is based on current projections of annual PEV sales from the Energy Information Administration (EIA). The "High PEV" scenario is based on the level of PEV penetration that would be required to get onto a trajectory to reduce light-duty GHG emissions in the state by 70 - 80 percent from current levels by 2050. The moderate PEV (EIA) scenario is essentially a "business as usual" scenario that continues current trends. However, the significantly higher levels of PEV penetration in the high 80x50 scenario are unlikely to be achieved without additional aggressive policy action at the state and local level, to incentivize individuals to purchase PEVs, and to support the necessary roll-out of PEV charging infrastructure. See Figure 3 for a comparison of the two scenarios through 2050.

Figure 3 Comparison of PEV Penetration Scenarios



[3] PEVs include battery-electric vehicles (BEV) and plug-in hybrid vehicles (PHEV). This study focused on passenger vehicles and trucks; there are opportunities for electrification of non-road equipment and heavy-duty trucks and buses, but evaluation of these applications was beyond the scope of this study.

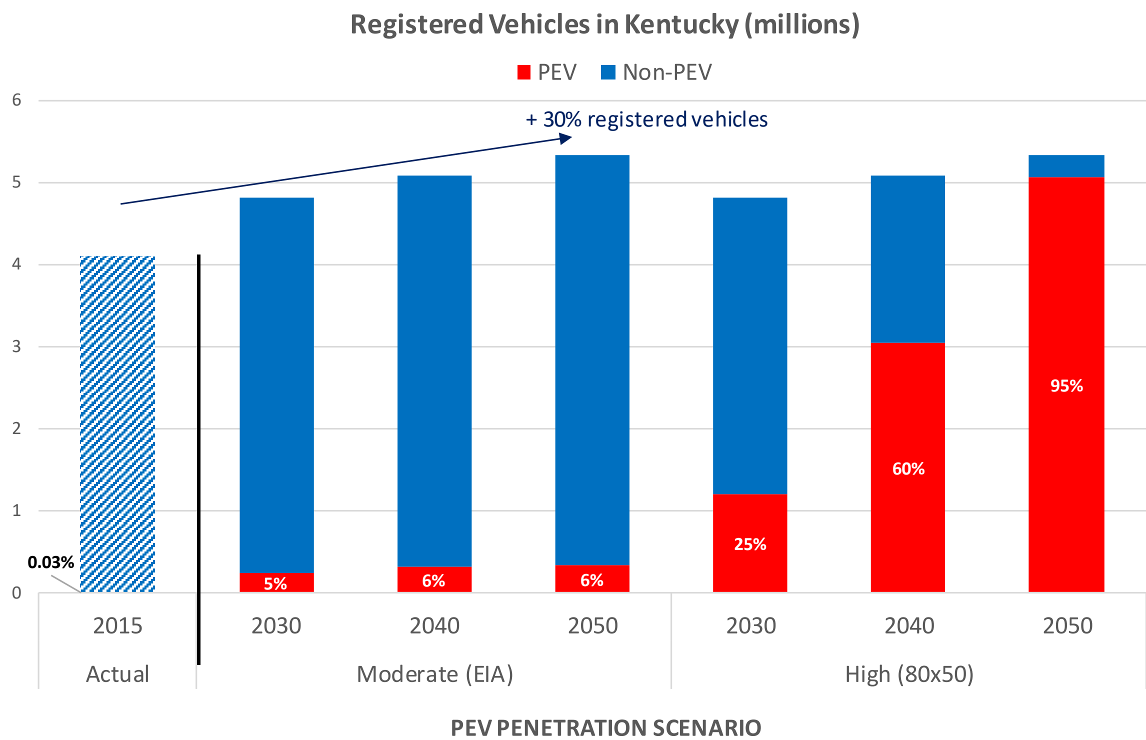
Plug-in Electric Vehicles, Electricity Use, and Charging Load

Vehicles and Miles Traveled

The projected number of PEVs and conventional gasoline vehicles in the Kentucky light duty fleet[4] under each PEV penetration scenario is shown in Figure 4, and the projected annual miles driven by these vehicles is shown in Figure 5. Under the Moderate PEV (EIA) scenario, the number of PEVs registered in Kentucky would increase from approximately 1,400 today to 236,000 in 2030, 314,500 in 2040, and 330,700 in 2050. Under the High PEV (80x50) scenario there would be 1.2 million PEVs in Kentucky by 2030, rising to 3.0 million in 2040, and 5.0 million in 2050. This equates to 25 percent of in-use light duty vehicles in Kentucky in 2030, rising to 60 percent in 2040 and 95 percent in 2050. [5]

This analysis estimates that under the High PEV (80x50) scenario Kentucky will reduce light-duty fleet gasoline consumption in 2050 by 52 percent compared to a baseline with no PEVs, due to 87 percent of fleet miles being driven by PEVs on electricity (Figure 5). However, to achieve this level of electric miles, 95 percent of light-duty vehicles will be PEVs, including PHEVs (Figure 4).

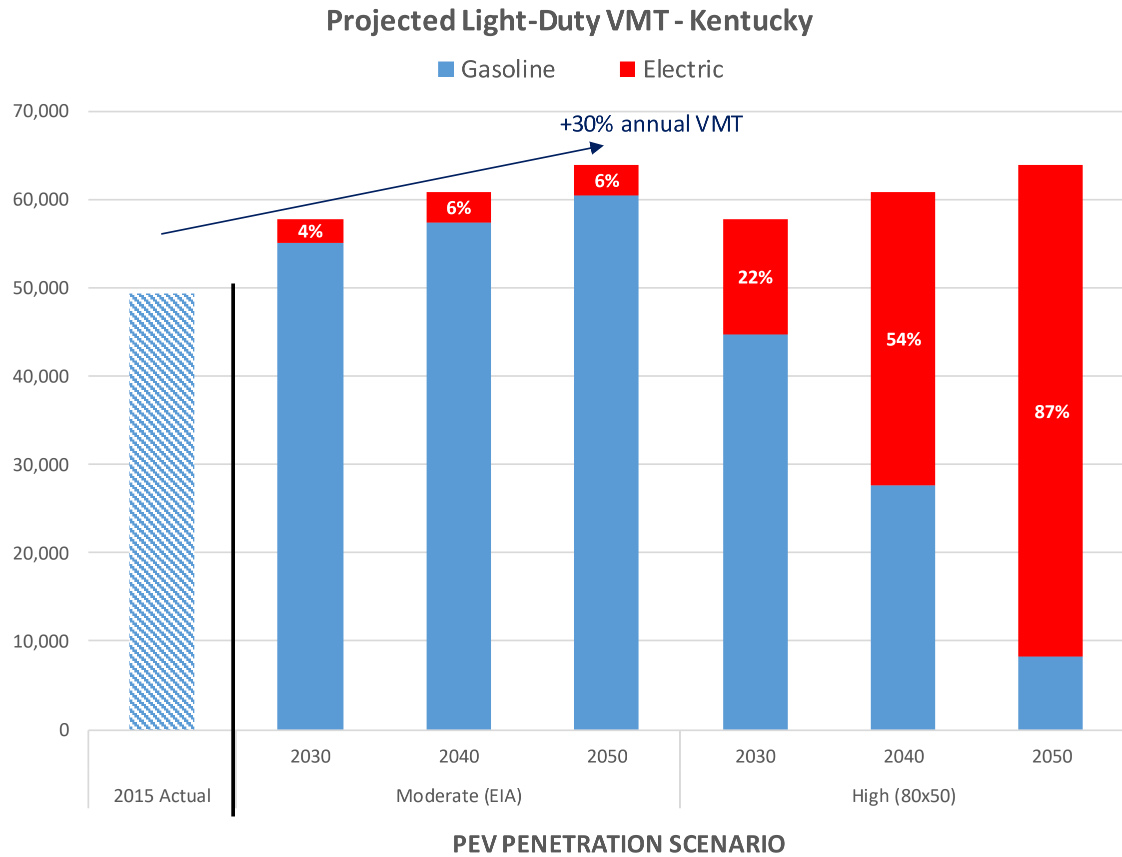
Figure 4 Projected Kentucky Light Duty Fleet



[4] This analysis only includes cars and light trucks. It does not include medium- or heavy-duty trucks and buses.

[5] Note that under both PEV penetration scenarios the percentage of total VMT driven by PEVs on electricity each year is lower than the percentage of PEVs in the fleet. This is because PHEVs are assumed to have a "utility factor" less than one – i.e., due to range restrictions a PHEV cannot convert 100 percent of the miles driven annually by a baseline gasoline vehicle into miles powered by grid electricity. In this analysis PHEVs are assumed to have an average utility factor of 85 percent.

Figure 5 Projected Kentucky Light Duty Fleet Vehicle Miles Traveled (million miles)

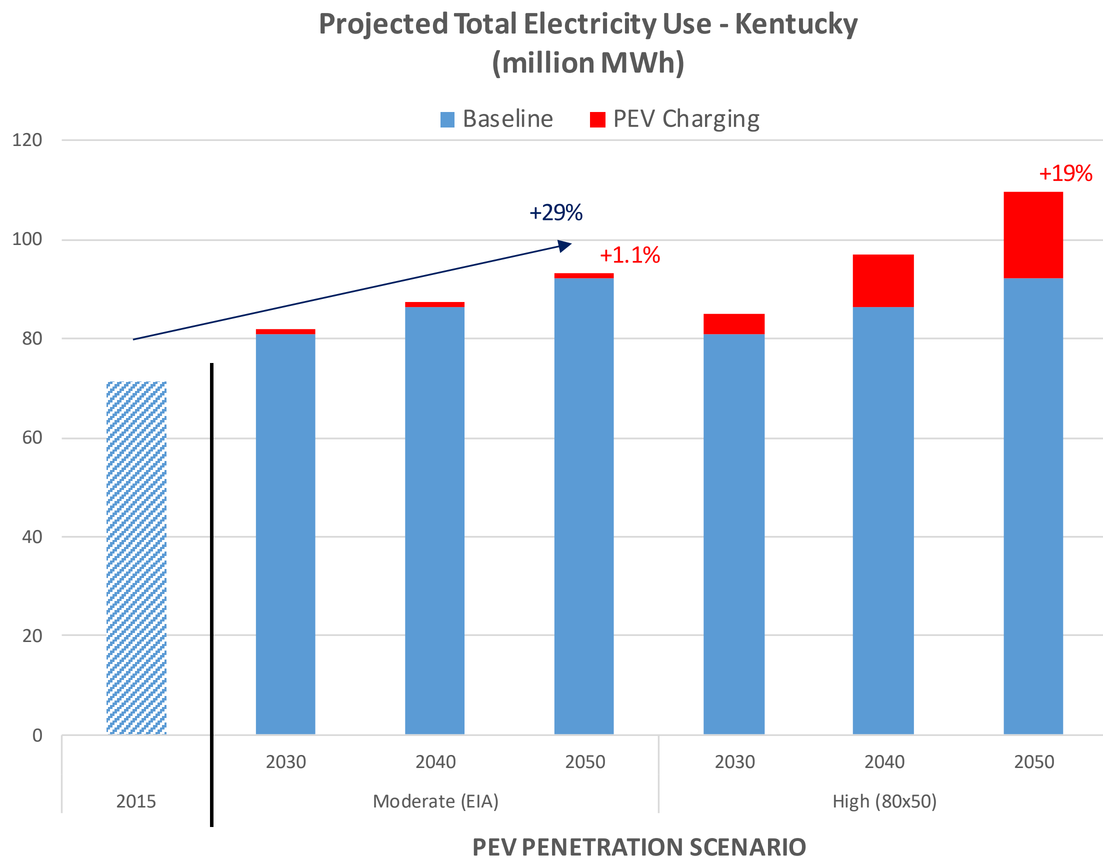


PEV Charging Electricity Use

The estimated total PEV charging electricity used in Kentucky each year under the PEV penetration scenarios is shown in Figure 6.

In Figure 6, projected baseline electricity use without PEVs is shown in blue and the estimated incremental electricity use for PEV charging is shown in red. State-wide electricity use in Kentucky is currently 71 million MWh per year. Annual electricity use is projected to increase to 81 million MWh in 2030 and continue to grow after that, reaching 92 million MWh in 2050 (29 percent greater than 2015 levels).

Figure 6 Estimated Total Electricity Use in Kentucky



Under the Moderate PEV penetration scenario, electricity used for PEV charging is projected to be 0.8 million MWh in 2030 – an increase of about 1.0 percent over baseline electricity use. By 2050, electricity for PEV charging is projected to grow to 1.0 million MWh – an increase of 1.1 percent over baseline electricity use. Under the High PEV (80x50) scenario electricity used for PEV charging is projected to be 4.1 million MWh in 2030, growing to 17.5 million MWh and adding 19 percent to baseline electricity use in 2050.

PEV Charging Load

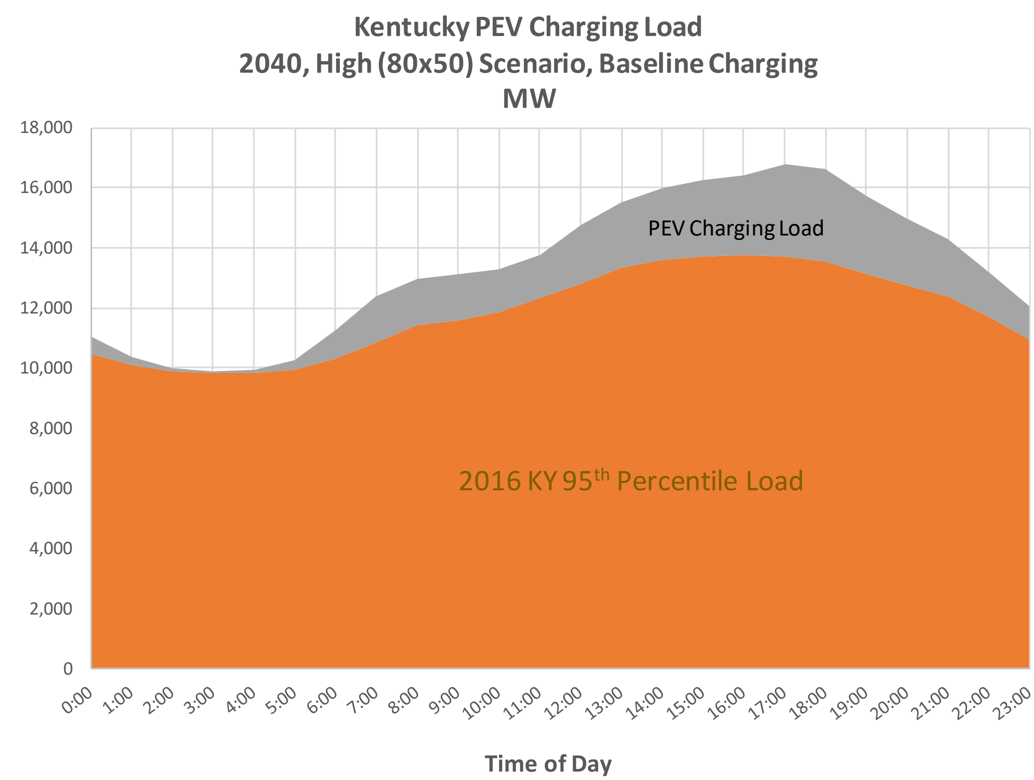
This analysis evaluated the effect of PEV charging on the Kentucky electric grid under two different charging scenarios. Under both scenarios 77 percent of all PEVs are assumed to charge exclusively at home and 23 percent are assumed to charge at locations other than at home (i.e. at work or at other "public" chargers). Under the baseline charging scenario all Kentucky drivers who charge at home are assumed to plug-in their vehicles and start charging as soon as they arrive at home each day, while under the managed charging scenario a significant portion of PEV owners are assumed to participate in a utility managed charging program to minimize PEV charging load in the late afternoon and early evening when other electricity demand is high.[6]

[6] Utilities have many policy options to incentivize managed PEV charging. This analysis does not compare the efficacy of different options. For this analysis, managed charging is modeled as 85% of PEV owners that arrive home between noon and 11 pm delaying the start of charging until between Midnight and 2 am. This is only one of many managed charging program options that are available to utilities.

See Figure 7 (baseline) and Figure 8 (managed) for a comparison of PEV charging load under the baseline and managed charging scenarios, using the 2040 High (80x50) PEV penetration scenario as an example. In each of these figures the 2016 Kentucky 95th percentile load (MW)[7] by time of day is plotted in orange, and the projected incremental load due to PEV charging is plotted in grey.

In 2016, daily electric load in Kentucky was generally less than 10,000 MW from midnight to 5 AM, ramping up to about 11,500 MW at 8 or 9 AM, and continuing to climb up to peak at approximately 13,700 MW between 3 PM and 5 PM, and then falling off through the evening hours.[8]

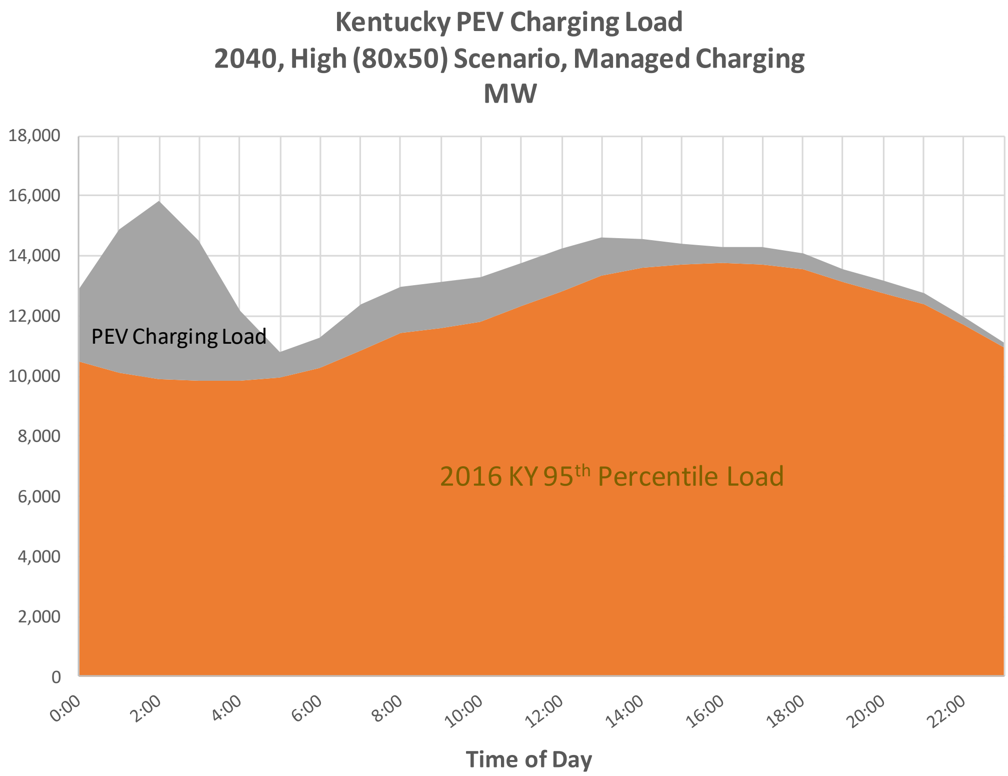
Figure 7 2040 Projected Kentucky PEV Charging Load, Baseline Charging (High PEV [80x50] scenario)



As shown in Figure 7, baseline PEV charging is projected to add load primarily between 8 AM and 8 PM, as some people charge at work early in the day, but most charge at home in the late afternoon and early evening. Under the baseline charging scenario, the PEV charging peak coincides with the existing summer afternoon peak load period between 3 PM and 5 PM.

[7] For each hour of the day actual load in 2016 was higher than the value shown on only 5 percent of days (18 days).
[8] In Figures 7 and 8, 95th Percentile Load is shown for the entire state of Kentucky across the entire year.

Figure 8 2040 Projected Kentucky PEV Charging Load, Managed Charging (High PEV [80x50] scenario)

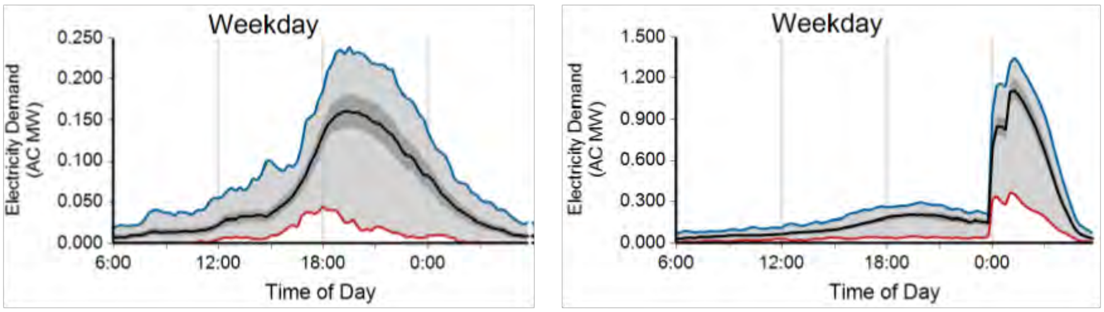


As shown in Figure 8, managed charging significantly reduces the incremental PEV charging load during the summer afternoon peak load period, but creates a secondary peak in the early morning hours, between midnight and 4 AM. The shape of this early morning peak can potentially be controlled based on the design of managed charging incentives.

These baseline and managed load shapes are consistent with real world PEV charging data collected by the EV Project, as shown in Figure 9. In Figure 9 the graph on the left shows PEV charging load in the Dallas/Ft Worth area where no managed charging incentive was offered to drivers. The graph on the right shows PEV charging load in the San Diego region, where the local utility offered drivers a time-of-use rate with significantly lower costs ($/kWh) for charging during the "super off-peak" period between midnight and 5 a.m. [2]

Figure 9 PEV Charging Load in Dallas/Ft Worth and San Diego areas, EV Project

Blue line = maximum demand Black line = median demand Red line = minimum demand



Dallas/Ft Worth (standard rates)

San Diego (time-of-use rates)

See Table 1 for a summary of the projected incremental afternoon peak hour load (MW) in Kentucky, from PEV charging under each penetration and charging scenario. This table also includes a calculation of how much this incremental PEV charging load would add to the 2016 95th percentile peak hour load. Under the Moderate PEV (EIA) penetration scenario, PEV charging would add 241 MW of load during the afternoon peak load period on a typical weekday in 2030, which would increase the 2016 baseline peak load by about 1.8 percent. By 2050, the afternoon incremental PEV charging load would increase to 303 MW, adding 2.2 percent to the 2016 baseline afternoon peak. By comparison the afternoon peak hour PEV charging load in 2030 would be only 46 MW for the managed charging scenario, increasing to 60 MW in 2050.

Under the High PEV (80x50) penetration scenario, baseline PEV charging would increase the total 2016 afternoon peak electric load by about 38 percent in 2050, while managed charging would only increase it by about 7 percent.[9]

Table 1 Projected Incremental Afternoon Peak Hour PEV Charging Load (MW)

		Moderate PEV (EIA)			**High PEV (80x50)**		
		2030	**2040**	**2050**	**2030**	**2040**	**2050**
Baseline Charging	PEV Charging (MW)	241	288	303	1,102	3,108	5,172
	Increase relative to 2016 Peak	1.8%	2.1%	2.2%	8.0%	22.6%	37.6%
Managed Charging	PEV Charging (MW)	46	57	60	217	592	986
	Increase relative to 2016 Peak	0.3%	0.4%	0.4%	1.6%	4.3%	7.2%

[9] Given projected significant increases in total state-wide electricity use through 2050, baseline peak load (without PEVs) is also likely to be higher in 2050 than 2016 peak load; as such the percentage increase in baseline peak load due to high levels of PEV penetration is likely to be lower than that shown in Table 1. The incremental costs of adding this peak capacity are accounted for in the analysis. As discussed below, even when accounting for these costs there are still net rate-payer benefits from high levels of PEV penetration. As the analysis shows, the net rate-payer benefits are higher with managed charging, because the cost of serving the incremental peak load is lower.

As discussed below, increased peak hour load increases a utility's cost of providing electricity, and may result in the need to upgrade distribution infrastructure. As such, managed PEV charging can provide additional net benefits to all utility customers, by reducing the cost of providing electricity used to charge PEVs.

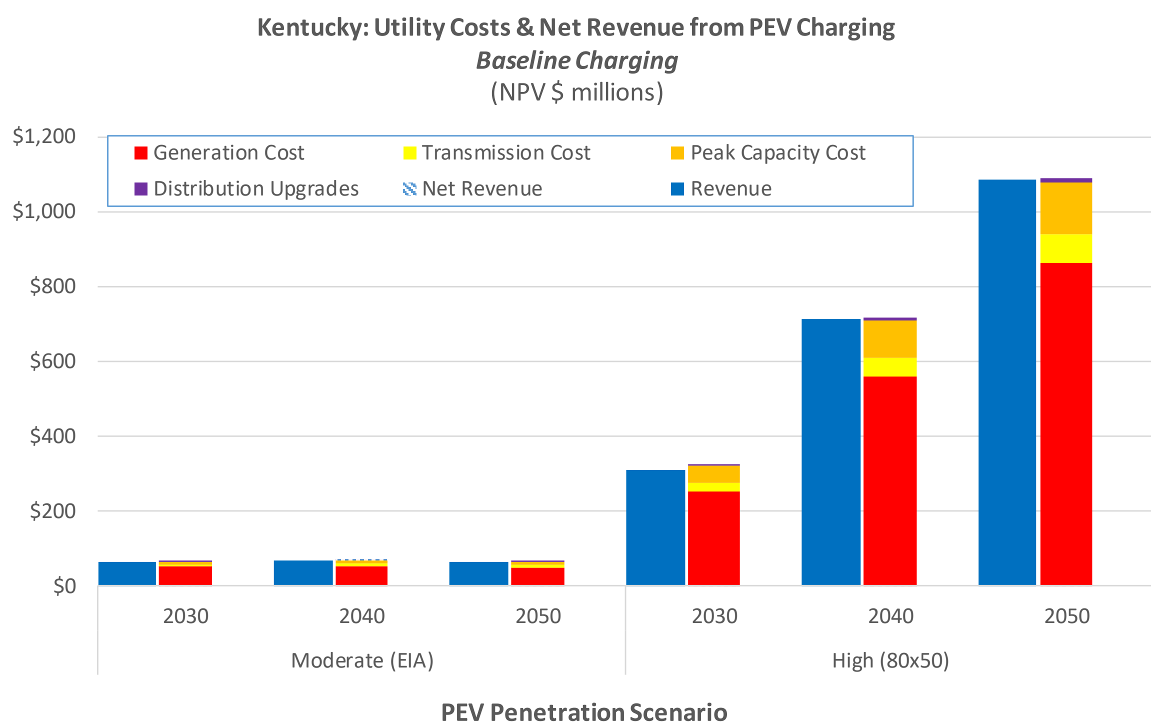
Utility Customer Benefits

The estimated NPV of annual revenues and costs in 2030, 2040, and 2050, for Kentucky's electric utilities to supply electricity to charge PEVs under each penetration scenario are shown in Figure 10, assuming the baseline PEV charging scenario.

Under the Moderate PEV penetration scenario, the NPV of annual revenue from electricity sold for PEV charging in Kentucky is projected to total $63 million in 2030 and in 2050. Under the High PEV (80x50) scenario, the NPV of annual utility revenue from PEV charging is projected to total $309 million in 2030, rising to $1.0 billion in 2050.

In Figure 10, projected annual utility revenue is shown in dark blue. The different elements of incremental annual cost that utilities would incur to purchase and deliver additional electricity to support PEV charging are shown in red (generation), yellow (transmission), orange (peak capacity), and purple (infrastructure upgrade cost). Generation and transmission costs are proportional to the total power (MWh) used for PEV charging, while peak capacity costs are proportional to the incremental peak load (MW) imposed by PEV charging. Infrastructure upgrade costs are costs incurred by the utility to upgrade their distribution infrastructure to handle the increased peak load imposed by PEV charging.

Figure 10 NPV of Projected Annual Utility Revenue and Costs from Baseline PEV Charging



As shown in Figure 10, for both the Moderate PEV and High PEV (80x50) penetration scenarios, under the baseline charging scenario annual utility revenue from PEV charging is marginally lower than the annual incremental costs of serving the PEV charging load, resulting in zero or just slightly negative "net revenue"

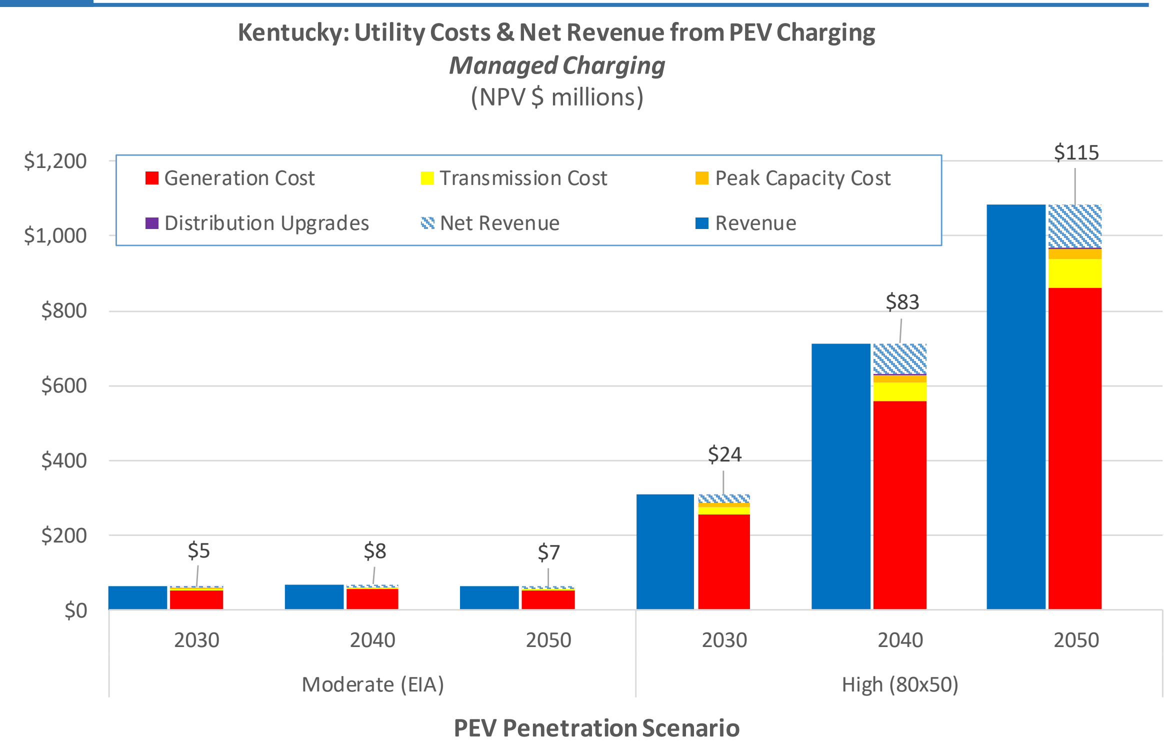
(revenue minus costs) to the utility. This is due to the annual incremental cost of serving PEV charging peak load (cost of new capacity and distribution upgrades), which is slightly higher than the net revenue that utilities will receive under current rate structures (net of generation and transmission costs). Net revenue is normally shown as striped light blue bars and represents what utilities would realize from selling additional electricity for PEV charging. Under the Moderate PEV penetration scenario, the NPV of net annual revenue in Kentucky is projected to be -$4 million in 2030, falling to -$0.4 million in 2050. Under the High PEV (80x50) scenario, the NPV of utility net annual revenue from PEV charging is projected to total -$14 million in 2030, falling to -$6 million in 2050.

In Kentucky, utilities will need to rely on some form of managed PEV charging to limit incremental peak capacity costs, which are a major contributor to the negative net revenue shown above.

Figure 11 summarizes the NPV of projected annual utility revenue, costs, and net revenue for managed charging under each PEV penetration scenario. Compared to baseline charging (Figure 10) projected annual revenue, and projected annual generation and transmission costs are the same, but projected annual peak capacity and infrastructure costs are lower due to a smaller incremental peak load (see Table 1).

Compared to baseline charging, managed charging provides positive annual utility net revenue (NPV) for both penetration scenarios for all years. Managed charging increases utility net revenue to $5 million in 2030 and $7 million in 2050 under the Moderate PEV penetration scenario, due to lower costs. Under the High PEV (80x50) scenario, managed charging will increase the NPV of annual utility net revenue to $24 million in 2030 and $115 million in 2050. The NPV of projected annual utility net revenue averages $21 per PEV in 2030, and $21 - $24 per PEV in 2050 if charging is managed.

Figure 11 NPV of Projected Annual Utility Revenue and Costs from Managed PEV Charging

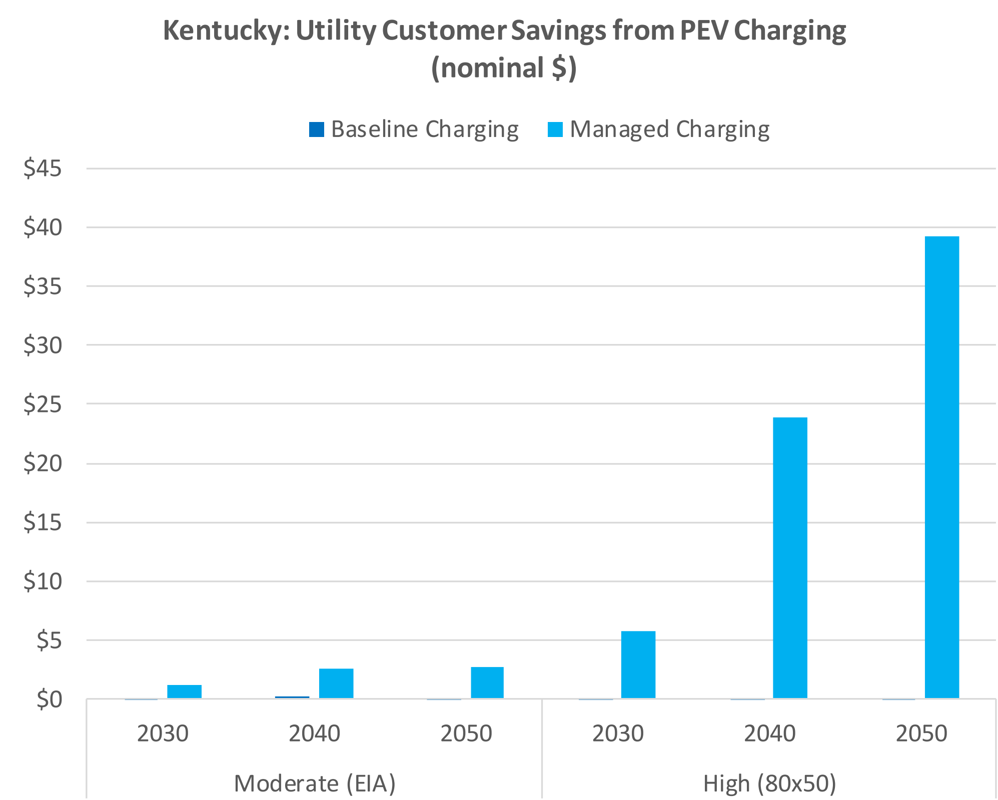


In general, a utility's costs to maintain their distribution infrastructure increase each year with inflation, and these costs are passed on to utility customers in accordance with rules established by the Kentucky Public Service Commission (PSC), via periodic increases in residential and commercial electric rates. However, under the PSC rules net revenue from additional electricity sales generally offset the allowable costs that can be passed on via higher rates. As such, the majority of projected utility net revenue from increased electricity sales for PEV charging (with managed charging) would in fact be passed on to utility customers in Kentucky, not retained by the utility companies.

Under current rate structures this net revenue would in effect put downward pressure on future rates, delaying or reducing future rate increases, thereby reducing electric bills for all customers. See Figure 12 for a summary of how the projected utility net revenue from PEV charging could affect average annual residential electricity bills for all Kentucky electric utility customers.[10] As shown in the figure, under the High PEV (80x50) scenario projected average electric rates in Kentucky could be reduced up to 1.7 percent in 2050 due to net revenue from PEV charging, resulting in an annual savings of approximately $39 (nominal dollars) per household in Kentucky. As discussed previously, baseline charging behavior results in negative net revenue under both penetration scenarios, which is why there are no utility customer savings in the figure.

It must be noted that how utility net revenue from PEV charging gets distributed is dependent on rate structure. Potential changes to current rates - to specifically incentivize off-peak PEV charging - could shift some or all of this benefit to PEV owners, thus reducing their electricity costs for vehicle charging without reducing costs for non-PEV owners. In either case, with even modest efforts to manage PEV charging rate payers who do not own a PEV will not be harmed by transportation electrification, and may benefit indirectly even if they continue to own gasoline vehicles.

Figure 12 Potential Effect of PEV Charging Net Revenue on Utility Customer Bills (nominal $)



[10] Based on 2016 average electricity use of 13,305 kWh per housing unit in Kentucky

Kentucky Driver Benefits

Current PEVs are more expensive to purchase than similar sized gasoline vehicles, but they are eligible for various government purchase incentives, including up to a $7,500 federal tax credit. These incentives are important to spur an early market, but as described below PEVs are projected to provide a lower total cost of ownership than conventional vehicles in Kentucky by about 2035, even without government purchase subsidies.

The largest contributor to incremental purchase costs for PEVs compared to gasoline vehicles is the cost of batteries. Battery costs for light-duty plug-in vehicles have fallen from over $1,000/kWh to less than $300/kWh in the last six years; many analysts and auto companies project that battery prices will continue to fall – to below $110/kWh by 2025, and below $75/kWh by 2030. [3]

Based on these battery cost projections, this analysis projects that the average annual cost of owning a PEV in Kentucky will fall below the average cost of owning a gasoline vehicle by 2035, even without government purchase subsidies.[11] See Table 2 which summarizes the average projected annual cost of Kentucky PEVs and gasoline vehicles under each penetration scenario.

All costs in Table 2 are in nominal dollars, which is the primary reason why costs for both gasoline vehicles and PEVs are higher in 2040 and 2050 than in 2030 (due to inflation). In addition, the penetration scenarios assume that the relative number of PEV cars and higher cost PEV light trucks will change over time; in particular the High PEV (80x50) scenario assumes that there will be a significantly higher percentage of PEV light trucks in the fleet in 2050 than in 2030, which further increases the average PEV purchase cost in 2050 compared to 2030.

Table 2 Projected Fleet Average Vehicle Costs to Vehicle Owners (nominal $)

GASOLINE VEHICLE		**Moderate (EIA)**			**High (80x50)**		
		2030	**2040**	**2050**	**2030**	**2040**	**2050**
Vehicle Purchase	$/yr	$5,257	$5,855	$7,167	$4,454	$6,125	$8,376
Gasoline	$/yr	$1,228	$1,396	$1,673	$1,198	$1,499	$1,972
Maintenance	$/yr	$274	$332	$410	$272	$340	$432
TOTAL ANNUAL COST	**$/yr**	**$6,759**	**$7,583**	**$9,251**	**$5,925**	**$7,964**	**$10,780**

PEV -KY		**Moderate (EIA)**			**High (80x50)**		
Baseline Charging/Standard Rate		**2030**	**2040**	**2050**	**2030**	**2040**	**2050**
Vehicle Purchase	$/yr	$5,257	$5,855	$7,167	$5,044	$6,436	$8,577
Electricity	$/yr	$412	$460	$538	$400	$490	$602
Gasoline	$/yr	$82	$98	$115	$80	$104	$133
Personal Charger	$/yr	$81	$99	$122	$81	$99	$122
Maintenance	$/yr	$168	$204	$251	$167	$207	$259
TOTAL ANNUAL COST	**$/yr**	**$6,000**	**$6,714**	**$8,194**	**$5,772**	**$7,335**	**$9,693**
Savings per PEV	**$/yr**	**$759**	**$869**	**$1,057**	**$153**	**$629**	**$1,087**

As shown in Table 2, under the High PEV Scenario (80x50) even in 2050 average PEV purchase costs are projected to be higher than average purchase costs for gasoline vehicles (with no government subsidies), but the annualized effect of this incremental purchase cost is outweighed by significant fuel cost savings, as well as

[11] The analysis assumes that all battery electric vehicles in-use after 2030 will have 200-mile range per charge and that all plug-in hybrid vehicles will have 50-mile all-electric range.

savings in scheduled maintenance costs. For the Moderate PEV Scenario in 2030, the average Kentucky PEV owner is projected to have annual operating savings of $759 due to reduced maintenance as well as electricity costs being lower than gasoline[12]. For both scenarios, this annual savings is projected to increase to $1,050 - $1,090 per PEV per year by 2050, as projected gasoline prices continue to increase faster than projected electricity prices.

The NPV of total annual cost savings to Kentucky drivers from greater PEV ownership are projected to be $115 million in 2030 rising to $124 million in 2050 under the moderate PEV penetration scenario. Under the High PEV (80x50) scenario, the NPV of total annual cost savings to Kentucky drivers from greater PEV ownership are projected to be $118 million in 2030, rising to $2.0 billion in 2050.

Other Benefits

Energy Security and Emissions Reductions

Along with the financial benefits to electric utility customers and PEV owners described above, light-duty vehicle electrification can provide additional benefits, including significant reductions in gasoline fuel use and transportation sector emissions.

The estimated cumulative fuel savings (barrels of gasoline[13]) from PEV use in Kentucky under each penetration scenario are shown in Figure 13. Annual fuel savings under the Moderate PEV penetration scenario are projected to total 0.9 million barrels in 2030, with cumulative savings of more than 20 million barrels by 2050. For the High PEV (80x50) scenario, annual fuel savings in 2030 are projected to be 4.2 million barrels, and by 2050 cumulative savings will exceed 236 million barrels.

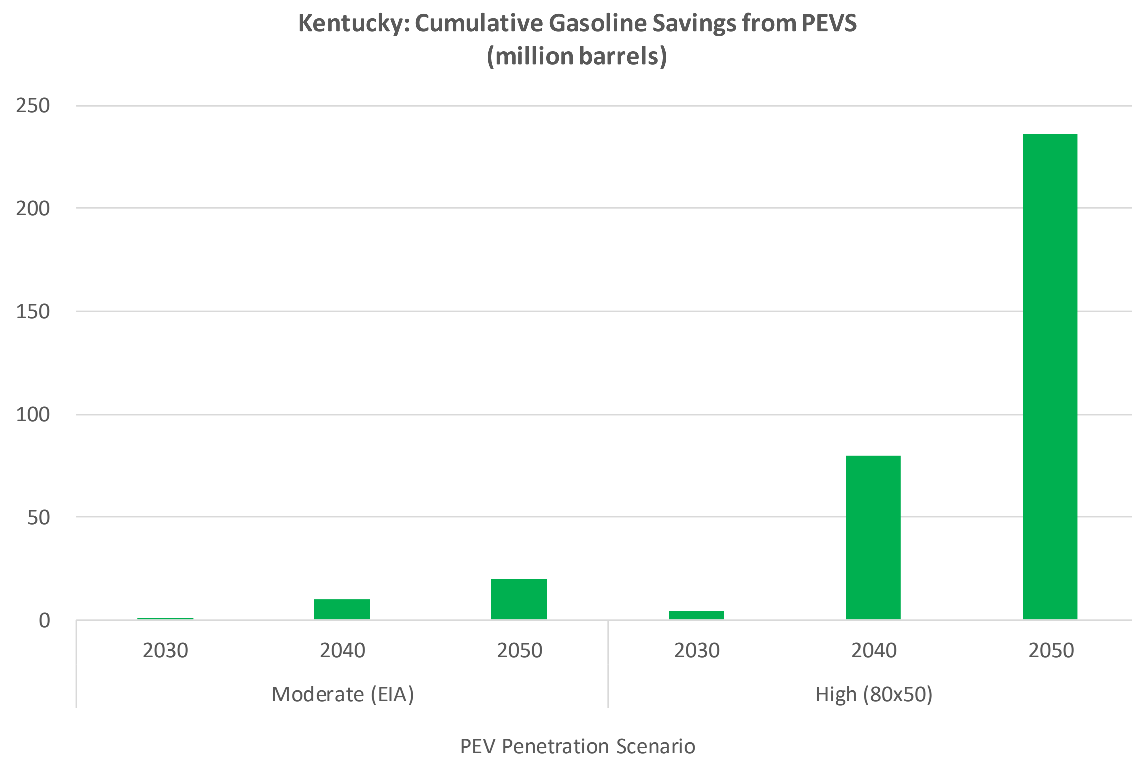
These fuel savings can help put the U.S. on a path toward energy independence, by reducing the need for imported petroleum. In addition, a number of studies have demonstrated that EVs can generate significantly greater local economic impact than gasoline vehicles - including generating additional local jobs - by keeping more of vehicle owners' money in the local economy rather than sending it out of state by purchasing gasoline.

[12] Under the moderate PEV (EIA) scenario, this analysis assumes that PEV owners will pay the same net purchase price for gasoline vehicles and PEVs, despite the higher projected purchase price of comparable PEVs. There is evidence that current PEV purchasers are foregoing the purchase of more expensive vehicles to purchase higher-priced PEVs within their target budget. With only modest future PEV penetration this analysis assumes that this behavior will continue. However, for the High PEV scenario net PEV owner benefits reflect the fact that PEV purchasers will pay a higher price for their PEVs than they would have paid for a similar gasoline vehicle.

[13] One barrel of gasoline equals 42 US gallons

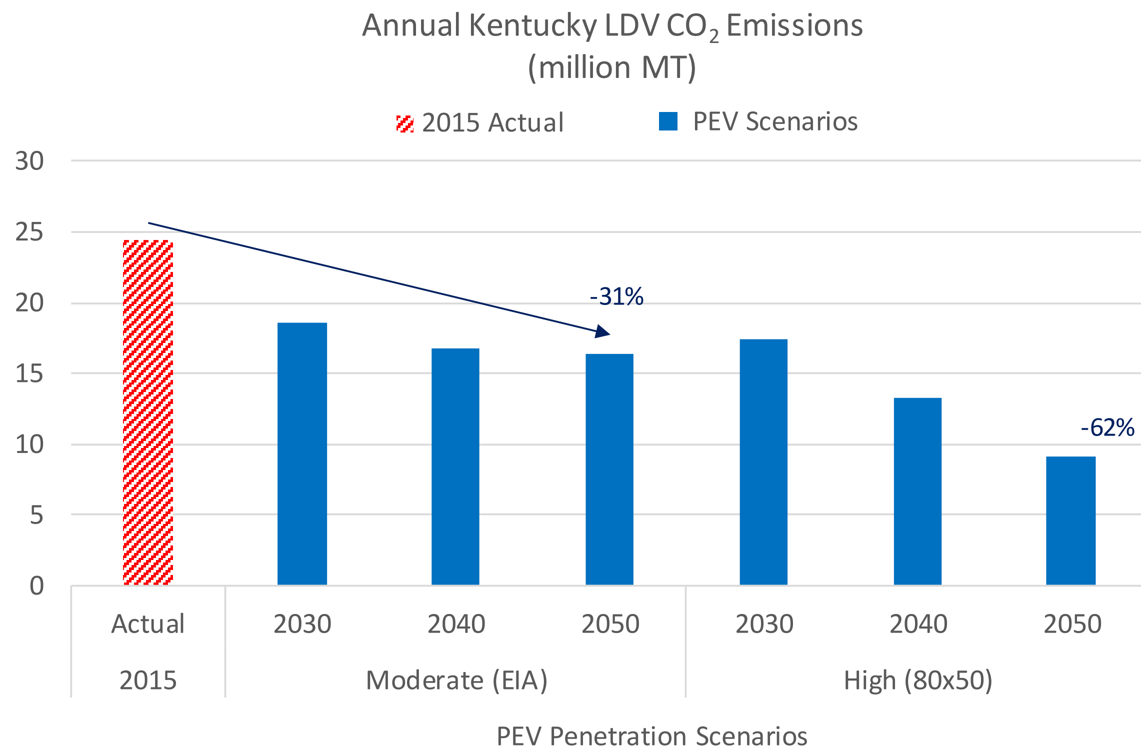
Economic impact analyses for the states of California, Florida, Ohio and Oregon have estimated that for every million dollars in direct PEV owner savings, an additional $0.29 - $0.57 million in secondary economic benefits will be generated within the local economy, depending on PEV adoption scenario. These studies also estimated that between 13 and 25 additional in-state jobs will be generated for every 1,000 PEVs in the fleet. [1]

Figure 13 Cumulative Gasoline Savings from PEVs in Kentucky



The projected annual greenhouse gas (GHG) emissions (million metric tons carbon-dioxide equivalent, CO_2-e million tons) from the Kentucky light duty fleet under each PEV penetration scenario are shown in Figure 14. In this figure, projected emissions under the PEV scenarios are shown in blue. The values shown represent "wells-to-wheels" emissions, including direct tailpipe emissions and "upstream" emissions from production and transport of gasoline. Estimated emission for the PEV scenarios includes GHG emissions from generating electricity to charge PEVs, as well as GHG emissions from gasoline vehicles in the fleet. Estimated emissions from PEV charging are based on EIA projections of average carbon intensity for the Reliability First Corporation / West electricity market module region, which includes Kentucky.

Figure 14 Projected GHG Emissions from the Light Duty Fleet in Kentucky



As shown in Figure 14, GHG emissions from the light duty fleet in Kentucky were approximately 24 million metric tons in 2015.

Compared to 2015 baseline emissions, in 2050 GHG emissions are projected to be reduced by up to 8 million tons under the Moderate PEV penetration scenario and as much as 15 million tons under the High PEV (80x50) scenario. Through 2050, cumulative net GHG emissions are projected to be reduced by nearly 152 million tons under the Moderate PEV penetration scenario and 234 million metric tons under the High PEV (80x50) scenario.

NOx Emissions

In 2015 the Electric Power Research Institute (EPRI), in conjunction with the Natural Resources Defense Council (NRDC), conducted national-level modeling to estimate GHG and air quality benefits from high levels of transportation electrification [4]. Under their electrification scenario EPRI estimated that NOx would be reduced by 11.4 tons and VOCs would be reduced by 5.5 tons, for every billion vehicle miles traveled[14].

Extrapolating from this data, under the Moderate PEV Scenario (EIA), by 2050 light-duty vehicle electrification in Kentucky could reduce annual NOx emissions by 240 tons and reduce annual VOC emissions by 116 tons.

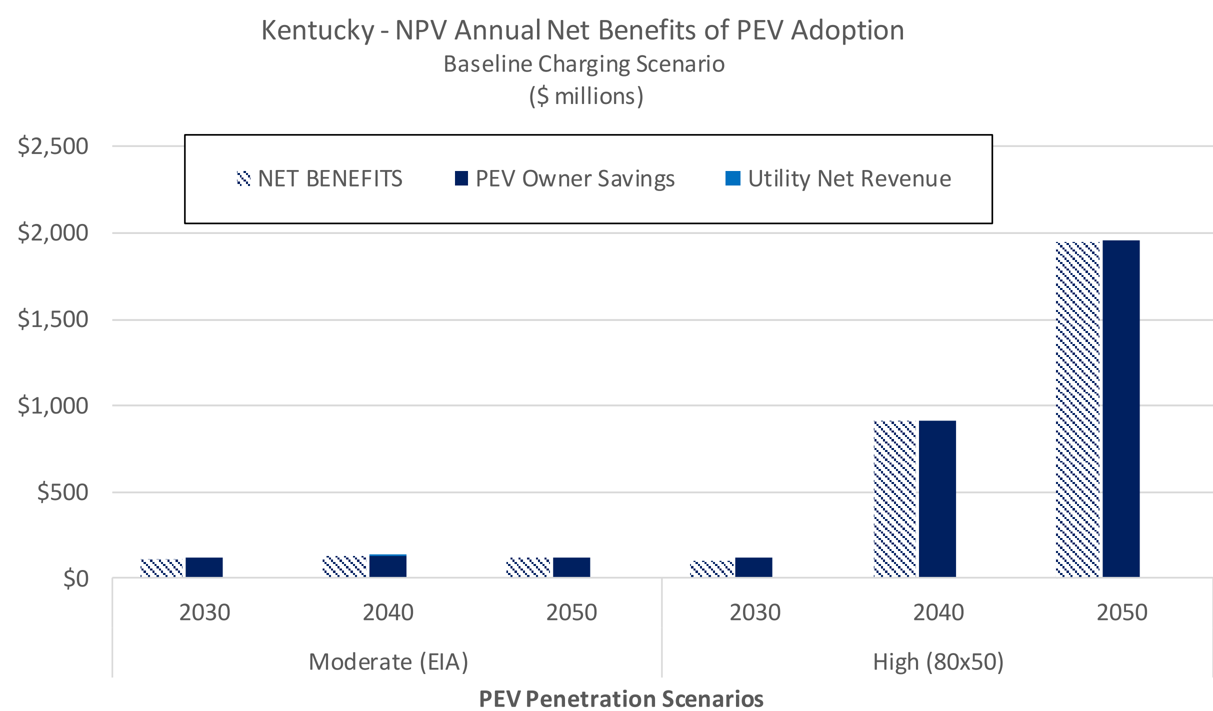
[14] For light-duty vehicles the analysis assumed that by 2030 approximately 17 percent of annual vehicle miles would be powered by grid electricity, using PEVs. Based on current and projected electric sector trends the analysis also assumed that approximately 49 percent of the incremental power required for transportation electrification in 2030 would be produced using solar and wind, with the remainder produced by combined cycle natural gas plants.

Under the High PEV Scenario (80x50), total NOx reductions in 2050 could reach more than 3,740 tons per year, and total VOC reductions could reach 1,800 tons per year.[15]

Total Societal Benefits

The NPV of total annual estimated benefits from increased PEV use in Kentucky under each PEV penetration scenario are summarized in Figures 15 and 16. These benefits include cost savings to Kentucky drivers and utility customer savings from reduced electric bills. Figure 15 shows the NPV of annual projected societal benefits if Kentucky drivers charge in accordance with the baseline charging scenario. Figure 16 shows the NPV of projected annual benefits with managed charging.

Figure 15 Projected NPV of Total Societal Benefits from Greater PEV use in KY – Baseline Charging

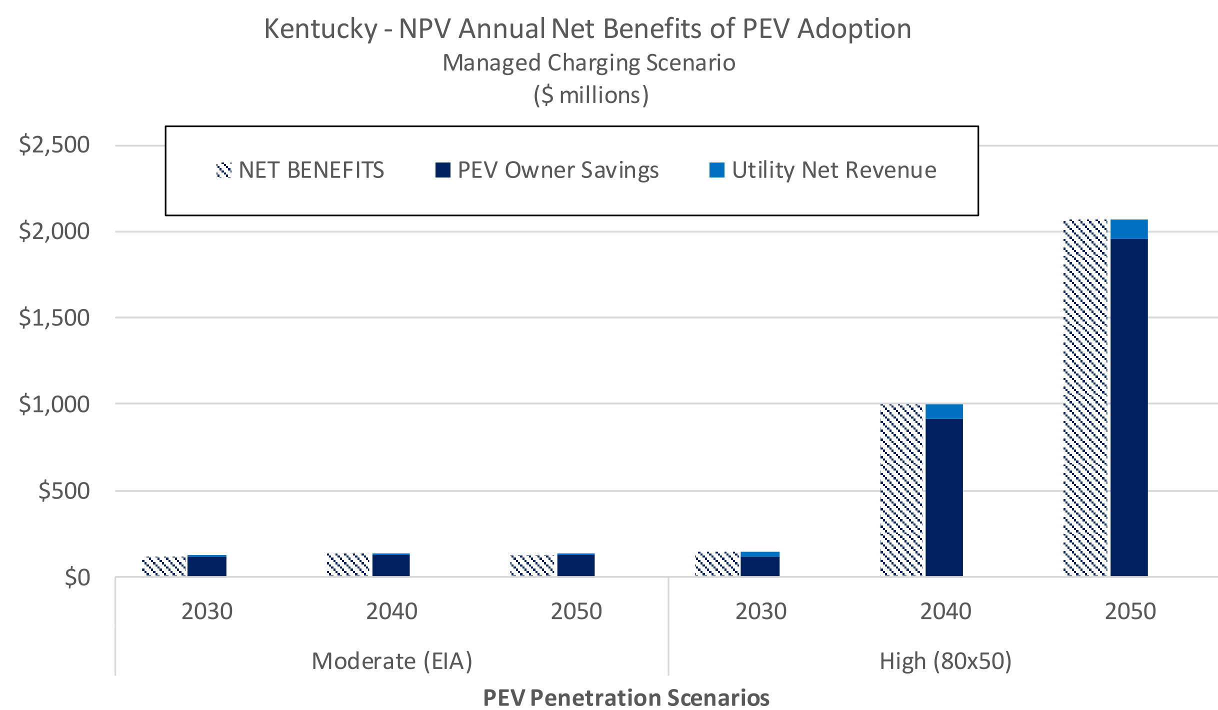


As shown in Figure 15, the NPV of annual benefits is projected to be a minimum of $124 million per year in 2050 under the Moderate PEV penetration scenario and $2.0 billion per year in 2050 under the High PEV (80x50) scenario. All of these annual benefits will accrue to Kentucky drivers as a cash savings in vehicle operating costs since utility net revenue is break-even to slightly negative under the baseline charging scenario, as discussed above.

[15] Across the entire state, estimated annual light-duty vehicle miles traveled (VMT) totals 0.64 trillion miles in 2050. Of these miles approximately, 6 percent are powered by grid electricity under the EIA penetration scenario, and 87 percent are powered by grid electricity under the 80x50 penetration scenario

As shown in Figure 16, the NPV of annual benefits in 2050 will increase by $7 million under the Moderate PEV (EIA) penetration scenario, and $121 million under the High PEV (80x50) scenario with managed charging. Of these increased benefits, all will accrue to electric utility customers as a reduction in their electricity bills.

Figure 16 Projected NPV of Total Societal Benefits from Greater PEV use in KY – Managed Charging



Study Methodology

This section briefly describes the methodology used for this study. For more information on how this study was conducted, including a complete discussion of the assumptions used and their sources, see the report: *Mid-Atlantic and Northeast Plug-in Electric Vehicle Cost-Benefit Analysis, Methodology & Assumptions* (October 2016).[16] This report can be found at:

http://mjbradley.com/sites/default/files/NE_PEV_CB_Analysis_Methodology.pdf

This study evaluated the costs and benefits of two distinct levels of PEV penetration in Kentucky between 2030 and 2050, based on the range of publicly available PEV adoption estimates from various analysts.

Moderate PEV Scenario –EIA: Based on EIA's current projections for new PEV sales between 2015 and 2050, as contained in the 2017 Annual Energy Outlook (AEO). Under this scenario approximately 4.9 percent of in-use light duty vehicles in Kentucky will be PEV in 2030, rising to 6.2 percent in 2040 and remaining steady through 2050.

High PEV Scenario – 80x50: PEV penetration levels each year that would put the state on a trajectory to reduce total annual light-duty fleet GHG emissions by 70 – 80 percent from current levels in 2050. Under this scenario 25 percent of in-use vehicles will be PEV in 2030, rising to 60 percent in 2040 and 95 percent in 2050.

Both of these scenarios are compared to a baseline scenario with very little PEV penetration, and continued use of gasoline vehicles. The baseline scenario is based on future annual vehicle miles traveled (VMT) and fleet characteristics (e.g., cars versus light trucks) as projected by the Energy Information Administration in their most recent Annual Energy Outlook (AEO 2017).

Based on assumed future PEV characteristics and usage, the analysis projects annual electricity use for PEV charging at each level of penetration, as well as the average load from PEV charging by time of day. The analysis then projects the total revenue that Kentucky's electric distribution utilities would realize from sale of this electricity, their costs of providing the electricity to their customers, and the potential net revenue (revenue in excess of costs) that could be used to support maintenance of the distribution system.

The costs of serving PEV load include the cost of electricity generation, the cost of transmission, incremental peak generation capacity costs for the additional peak load resulting from PEV charging, and annual infrastructure upgrade costs for increasing the capacity of the secondary distribution system to handle the additional load.

For each PEV penetration scenario this analysis calculates utility revenue, costs, and net revenue for two different PEV charging scenarios: 1) a baseline scenario in which all PEVs are plugged in and start to charge as soon as they arrive at home each day, and 2) a managed charging scenario in which a significant portion of PEVs that arrive home between noon and 11 PM each day delay the start of charging until after midnight.

Real world experience from the EV Project demonstrates that, without a "nudge", drivers will generally plug in and start charging immediately upon arriving home after work (scenario 1), exacerbating system-wide evening peak demand.[17] However, if given a "nudge" - in the form of a properly designed and marketed financial

[16] This analysis used the same methodology as described in the referenced report, but used different PEV penetration scenarios, as described here. In addition, for this analysis fuel costs and other assumptions taken from the Energy Information Administration (EIA) were updated from EIA's Annual Energy Outlook 2016 to those in the Annual Energy Outlook 2017. Finally, for projections of future PEV costs this analysis used updated July 2017 battery cost projections from Bloomberg New Energy Finance.

[17] The EV Project is a public/private partnership partially funded by the Department of Energy which has collected and analyzed operating and charging data from more than 8,300 enrolled plug-in electric vehicles and approximately 12,000 public and residential charging stations over a two-year period.

incentive - many Kentucky drivers will choose to delay the start of charging until later times, thus reducing the effect of PEV charging on evening peak electricity demand (scenario 2). [5]

For each PEV penetration scenario, this analysis also calculates the total incremental annual cost of purchase and operation for all PEVs in the state, compared to “baseline” purchase and operation of gasoline cars and light trucks. For both PEVs and baseline vehicles annual costs include the amortized cost of purchasing the vehicle, annual costs for gasoline and electricity, and annual maintenance costs. For the Moderate PEV Scenario, it was assumed that PEV vehicle costs are the same as baseline gasoline vehicles, with the reasoning that consumers have a set budget and will purchase what they can afford, regardless of technology type. For the High PEV Scenario, the same logic could not be applied, as it is assumed that nearly all vehicle purchases will be PEV. For PEVs it also includes the amortized annual cost of the necessary home charger. This analysis is used to estimate average annual financial benefits to Kentucky drivers.

Finally, for each PEV penetration scenario this analysis calculates annual greenhouse gas (GHG) emissions from electricity generation for PEV charging, and compares that to baseline emissions from operation of gasoline vehicles. For the baseline and PEV penetration scenarios GHG emissions are expressed as carbon dioxide equivalent emissions (CO_2-e) in metric tons (MT). GHG emissions from gasoline vehicles include direct tailpipe emissions as well as “upstream” emissions from production and transport of gasoline.

For each PEV penetration scenario GHG emissions from PEV charging are calculated based on an electricity scenario that is consistent with the latest Energy Information Administration (EIA) projections for future SERC Reliability Corporation / Virginia -Carolina.

Net annual GHG reductions from the use of PEVs are calculated as baseline GHG emissions (emitted by gasoline vehicles) minus GHG emissions from each PEV penetration scenario.

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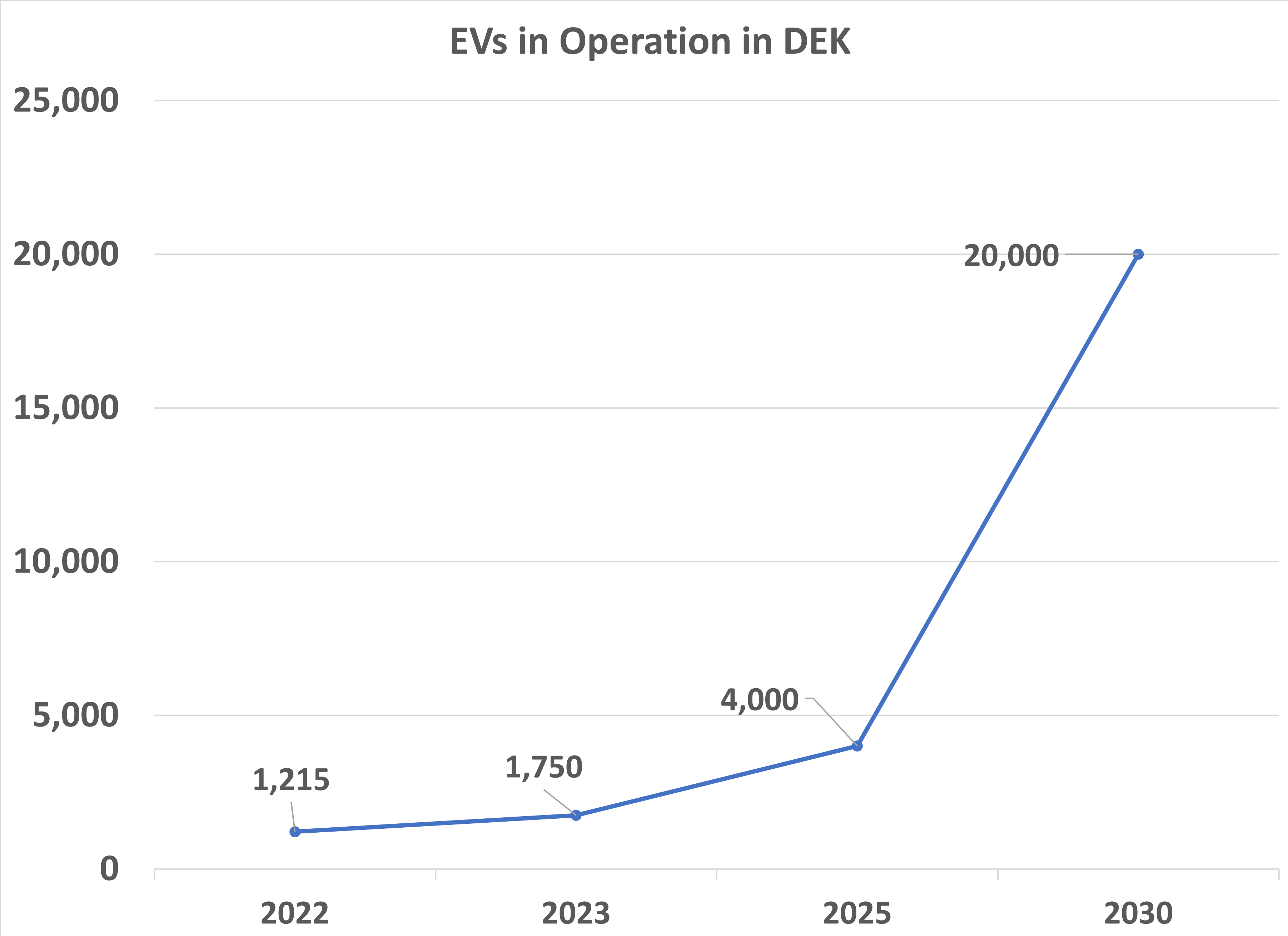
[4] U.S. Environmental Protection Agency, Office of Air and Radiation, Office of Air Quality Planning and Standards, Technical Support Document, Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors, Jan 2013, https://www.epa.gov/sites/production/files/2014-10/documents/sourceapportionmentbpttsd.pdf

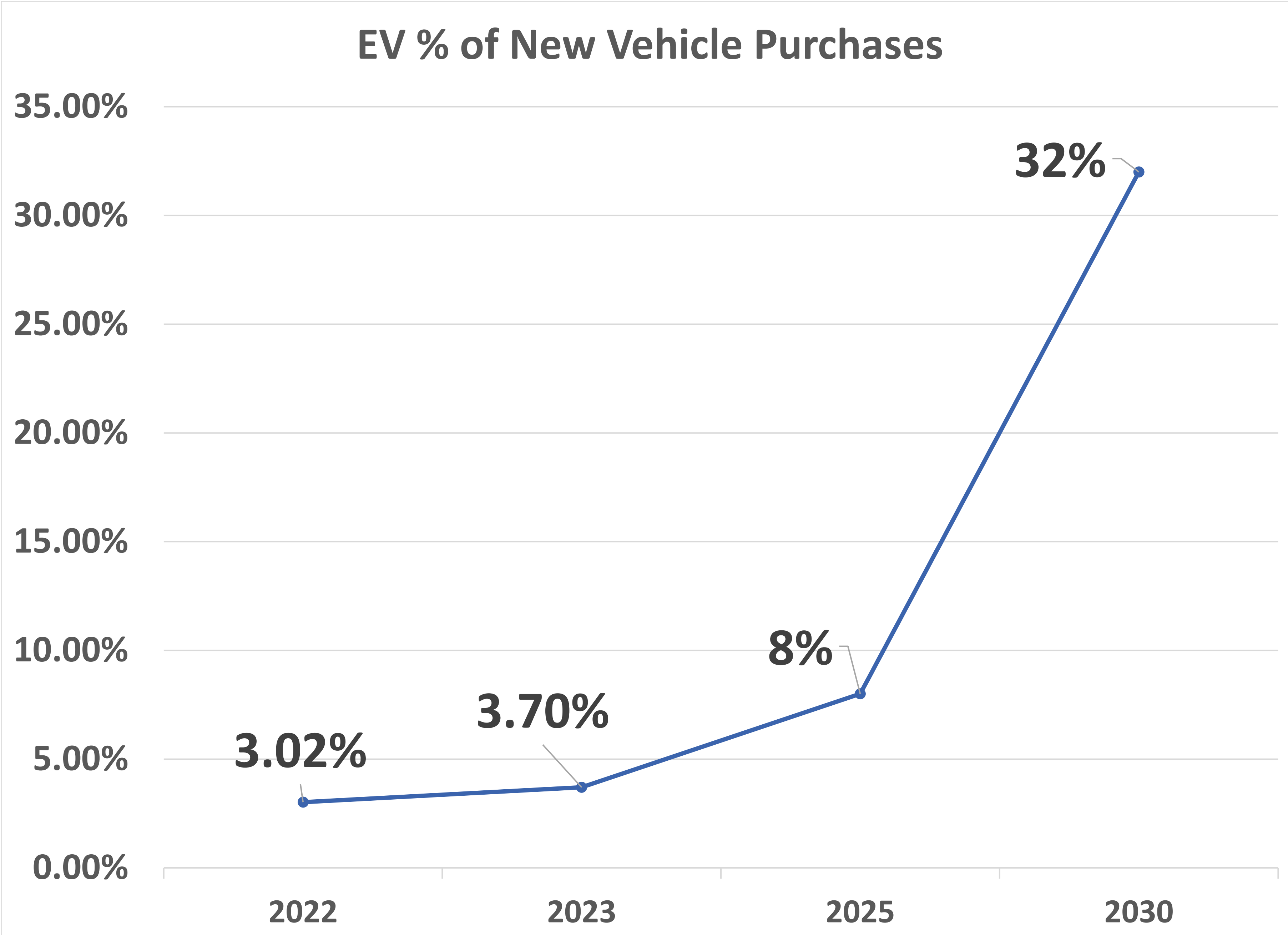
[5] Idaho National Laboratory, *2013 EV Project Electric Vehicle Charging Infrastructure Summary Report*, January 2013 through December 2013

Acknowledgements

Lead Authors: Dana Lowell, Brian Jones, and David Seamonds

This study was conducted by M.J. Bradley & Associates for Duke Energy. It is one of six state-level analyses that will be conducted of plug-in electric vehicle costs and benefits in the different U.S. states in which Duke operates. These studies are intended to provide input to state policy discussions about actions required to promote further adoption of electric vehicles, as well as to inform internal Duke planning efforts.


EVs in Operation in DEK
25,000
20,000
15,000
10,000
5,000
0
1,215
1,750
4,000
20,000
2022
2023
2025
2030


EV % of New Vehicle Purchases
35.00%
30.00%
25.00%
20.00%
15.00%
10.00%
5.00%
0.00%
3.02%
3.70%
8%
32%
2022
2023
2025
2030

Charger Solution Program Service Agreement

Duke Energy Kentucky, LLC ("***Duke Energy***") is excited to offer the Charger Solution Program known as "Charger Solution" (the "***Program***") established in accordance with the EVSE Tariff (the "***Tariff***") to its non-residential electric customers (each, a "***Customer***"). Customer's participation in the Program is subject to the terms and conditions of this Charger Solution Program Service Agreement and the applicable Program Statement of Work (the "***SOW***" and, collectively with the Charger Solution Program Service Agreement, the "***Service Agreement***").

1. Charger Solution Program Overview

1.1 Program Overview. Duke Energy is offering eligible Customers an opportunity to participate in a worry-free and affordable program to have electric vehicle ("***EV***") chargers at their business for a fee on their monthly electric bill. Under the Program, Duke Energy will provide Customer the option to select from Duke Energy's list of pre-qualified EV charger options, all of which meet the applicable technical and safety standards considered by Duke Energy. The customer may select one or more level 2 EV chargers or direct-current fast charging equipment ("***DCFC***" and the charging equipment selected by Customer, the "***Charging Equipment***"). The Charging Equipment will be installed at Customer's electric service address. A list of the approved Charging Equipment may be found on Duke Energy's website for the Program located at: https://www.duke-energy.com/energy-education/electric-vehicles (the "***Program Website***"). In addition, Customer will be able to select various extra equipment to use in connection with its selected Charging Equipment (such selected equipment, the "***Extra Facilities***"), the cost of which will not be included in the EVSE Fee (as defined below) as further set forth in Article 6. The Charging Equipment and any Extra Facilities (if any) selected by Customer shall be set forth on the SOW.

1.2 Installation. Once Customer selects Customer's Charging Equipment and is successfully enrolled in the Program in accordance with Article 3, Duke Energy will arrange to have one of Duke Energy's third party service technicians install the Charging Equipment and Extra Facilities, if necessary, at a time convenient for Customer during working hours between 7:00 A.M. local time and 7:00 PM local time ("***Working Hours***").

1.3 General Ownership and Maintenance. Once installed, Duke Energy will continue to own and maintain the Charging Equipment and Extra Facilities. Subject to the terms and conditions set forth herein, the costs of the Charging Equipment, installation, ongoing maintenance, and annual software networking fees (if any) will be included on Customer's monthly electric bill, as a convenient fee (such fee, the "***EVSE Fee***"). For the avoidance of doubt, the EVSE Fee shall not include charges for any Extra Facilities or any necessary excess facilities associated with Duke Energy's service regulations and/or line extension deposit requirements, electrical panel or wiring make-ready costs, costs for work on either side of the meter, non-standard equipment, after Working Hours service costs, costs for electricity usage or any other costs or expenses which Customer elects to incur which are expressly indicated in this Service Agreement or any other Program materials as being in addition to or outside of the EVSE Fee. Internet connectivity, arranged by Customer and at Customer's expense, may be required for Customer to participate in certain other Duke Energy programs that may be offered in conjunction with other Duke Energy tariffs but is not required to participate in this Program.

2. Eligibility and Availability

To be eligible to participate in the Program, Customer must:

- agree to the terms and conditions contained in this Service Agreement via submission of Customer's application to participate in the Program and execution of the SOW;

- be an electric customer in Duke Energy's service territory and have an active Duke Energy account that receives electric service;

- request installation of the Charging Equipment in a location that is (i) readily accessible in order to support installation and maintenance of the Charging Equipment, and (ii) meets the "Site Readiness" requirements (as specified on the Program Website);

- agree to cooperate with Duke Energy and provide Duke Energy with additional information or documents, including pictures of the Site (as defined below) or meter, that Duke Energy reasonably requires to determine Customer's eligibility to participate in the Program; and

- own or rent the applicable property; provided, that, if such Customer is renting, Customer's property or the Charging Equipment must have separately metered service, and Customer must: (i) obtain the building owner's written consent for Customer to participate in the Program, and (ii) agree that Customer's participation in the Program shall be terminated in accordance with Article 7 if the building owner revokes such consent.

3. **Enrollment Process**

3.1 Application. To enroll in the Program, Customer will need to complete the application found on the Program Website. Once Duke Energy has received Customer's complete application, Duke Energy will send Customer an email confirming (or declining) Customer's eligibility for the Program, subject to further review of the proposed Site and negotiation of an SOW. If Duke Energy confirms Customer's initial eligibility for the Program, Duke Energy will then perform any necessary visits of the proposed Site and Duke Energy and Customer will negotiate the SOW. The date that the SOW is executed will be considered Customer's "***Enrollment Date***".

3.2 Automatic Termination. If, at any time prior to the Activation Date (as defined below), Duke Energy determines that Customer is actually ineligible for the Program, or Duke Energy determines that it is not reasonably feasible to offer service or maintain Charging Equipment at the Site, Duke Energy shall notify Customer of the same and this Service Agreement will be deemed automatically terminated and will be of no further force or effect ("***Automatic Termination***").

3.3 Activation Date. Once the Charging Equipment has been installed at Customer's property (the "***Site***") (such date of installation, the "***Activation Date***"), Customer can start using the Charging Equipment located at the Site. Customer will receive its first bill in connection with the Program in the first billing period following the Activation Date. This first bill may be prorated depending on the Activation Date and Customer's billing cycle.

4. **Charging Equipment Installation and Maintenance**

Following the Enrollment Date, Duke Energy will, through its network of third party service technicians, provide, install, maintain, repair or replace the Charging Equipment (collectively the "***Work***") on the Site. The Site will be identified in the SOW. Duke Energy, in its sole discretion, shall have the right to repair, modify, or replace the Charging Equipment at any time during Customer's Term (as defined below). If safety, reliability, or access negatively affects delivery of service under this Service Agreement, then Duke Energy may withhold or discontinue service as it deems necessary. Duke Energy will use commercially reasonable efforts to maintain the Charging Equipment in working order, and will attempt to provide Customer reasonable advance notice of any required maintenance of the Charging Equipment. Duke Energy, or its service technicians, will coordinate with Customer to schedule maintenance Work during Working Hours. For an additional fee, maintenance may be scheduled after Working Hours, contingent on availability of an appropriate service technician, and such additional fee will be itemized on Customer's bill separate and distinct from the EVSE Fee. Customer understands that if Duke Energy is unable to arrange for maintenance Work to be completed at a mutually agreeable time, the Charging Equipment may not function and Customer and its customers and invitees may not be able to charge EVs using the Charging Equipment.

5. **Customer's Charging Equipment Obligations and Duties**

5.1 Access. During the Term (as defined below), Customer agrees to grant Duke Energy the necessary access to the Site and sufficient space to locate the Charging Equipment at the Site as may be deemed necessary or desirable by Duke Energy to perform the Work. Installations must conform to Duke Energy's specifications.

5.2 Customer Maintenance. During the Term, Customer will maintain the area surrounding the Charging Equipment and generally inspect the Charging Equipment and area surrounding the Charging Equipment and will promptly notify Duke Energy of any problems related to the Charging Equipment of which Customer becomes aware. For the avoidance of doubt, Customer is not responsible for the ongoing scheduled maintenance of the Charging Equipment.

5.3 Use of Charging Equipment. Customer will use the Charging Equipment only as specified by the Charging Equipment manufacturer and will be responsible for any damage caused to the Charging Equipment due to Customer's or its customers' or invitees' misuse, neglect, vandalism, or abuse. Customer agrees to remedy minor issues that do not require qualified service technicians to address, such as resetting infrequently tripped circuit breakers, reconnecting the plug and vehicle to engage charging, or resetting the network connection.

5.4 Networked Charging Equipment. For networked Charging Equipment, Customer shall provide and be responsible for maintaining communication access through wi-fi, cellular or other communications capabilities and any such costs of maintaining such communication access shall not be included in the EVSE Fee.

5.5 Third Party Access. Customer agrees to provide access and assistance to Duke Energy and/or Duke Energy's designated third-parties (including, without limitation, Duke Energy's network of third party service technicians) to facilitate random Charging Equipment testing. Such cooperation may include, but is not limited to, periodic inspection of the Charging Equipment and the addition of monitoring hardware or software at Duke Energy's expense.

6. **Applicable Charges**

6.1 Charges. Customer's participation in the Program will require Customer to pay for all electricity usage each month separate from the EVSE Fee. Customer will also be charged a monthly EVSE Fee for the Charging Equipment, the installation and maintenance services provided by Duke Energy and/or Duke Energy's designee, and any applicable network fees. The applicable monthly EVSE Fee is listed in the Tariff. In addition, Customer may elect to obtain certain Extra Facilities which shall not be included in the EVSE Fee. For Customer's convenience, Customer's monthly EVSE Fee and costs for Extra Facilities and any after Working Hours maintenance will each appear on Customer's Duke Energy electric bill as separate line items. Duke Energy will not provide a breakdown of the EVSE Fee, other than what is legally required. For the avoidance of doubt, Customer shall also be responsible for any applicable taxes. As set forth in Section 8.3, Duke Energy may provide Customer with a credit to its Duke Energy electric bill in certain instances. In the event Customer mandates specific pricing for the charging, Customer shall be solely responsible for the management and payment of any and all transactional fees as it pertains to the Customer, driver, and station network.

6.2 Deposit. Duke Energy may also, at its option, require a deposit not to exceed an aggregate amount of two (2) months of the EVSE Fees to be charged during the Term, which shall be applied to Customer's Duke Energy electric account after the first anniversary of the Activation Date provided Customer has met all of Customer's obligations under this Service Agreement.

7. **Term and Termination**

7.1 Term. This Service Agreement shall be effective as of the Enrollment Date. The term shall commence on the Enrollment Date and will continue for eight (8) years for DCFC units and 48 months for Level 2 units from the Activation Date, or until terminated in accordance with this Article 7 (the "***Term***"). At the end of the Term, unless this Service Agreement has already been terminated in accordance with this Article 7, Customer shall be given the option to: (i) extend the Term or enter into a new service agreement, at Duke Energy's sole discretion, (ii) assign the Charging Equipment to another party (with the written consent of Duke Energy, which Duke Energy may withhold in its sole discretion), or (iii) promptly make the Site available to Duke Energy and/or Duke Energy's designated third-party to access and remove the Charging Equipment from the Site.

7.2 Termination. This Service Agreement may be terminated at any time:

(a) subject to payment of the Termination Fee (as defined below) by Customer for any reason by providing Duke Energy thirty (30) calendar days of prior written notice of such termination;

(b) by Duke Energy for any reason by providing Customer thirty (30) calendar days prior written notice of such termination;

(c) by Duke Energy immediately if: (i) Customer fails to meet any of the Program eligibility requirements or adhere to any of Customer's obligations set forth in this Service Agreement in a manner that would make it unsafe for Customer to continue to participate in the Program, (ii) Customer rents the property where the Site is located and the property owner revokes its consent to Customer's participation in the Program, or (iii) Duke Energy is required to terminate the Program by the Commission (as defined below), and providing thirty (30) calendar days' notice would not be practicable or permitted by the Commission or other laws.

7.3 Automatic Termination. This Service Agreement shall be deemed terminated automatically:

(a) in the event an Automatic Termination occurs in accordance with Section 3.2; or

(b) in the event Customer sells, or no longer occupies at, the property where the Charging Equipment has been installed; provided, however, with Duke Energy's written consent, which Duke Energy may withhold at its sole discretion, Customer may seek (i) to assign the Charging Equipment and all rights and obligations hereunder to an existing or new property owner or tenant of the Site, provided such proposed transferee is a Duke Energy electric customer (a "***Permitted Assignment***"), or (ii) to move the Charging Equipment to a new property for a mutually agreed cost (a "***Permitted Move***).

7.4 Permitted Assignment; Permitted Move. Customer must submit a request for any Permitted Assignment or Permitted Move to Duke Energy as soon as practical but at least thirty (30) calendar days prior to the requested date of such Permitted Assignment or Permitted Move and, in the case of a Permitted Assignment, shall have the proposed transferee promptly contact Duke Energy. In the case of a Permitted Assignment or Permitted Move which is consented to in writing by Duke Energy, unless Duke Energy and Customer agree in writing otherwise, Customer shall pay all of Duke Energy's reasonable costs and expenses to move the Charging Equipment to a new property or assign the Charging Equipment and all rights and obligations hereunder to a new person, as applicable.

7.5 Hardware Change. Customer may request a change in charging equipment hardware during the Term by submitting a request to Duke Energy at least thirty (30) calendar days prior to Customer's preferred change in equipment. Customer shall pay all of Duke Energy's reasonable costs and expenses to remove the existing Charging Equipment and install the new charging equipment requested by Customer. Duke Energy and Customer will then terminate this Service Agreement and enter into a new Charger Solution Program Service Agreement for the new charging equipment hardware at the rate associated with the applicable charging equipment and associated network at the time of installation of the new charging equipment hardware.

7.6 Notice of Vacation. Notwithstanding anything to the contrary in Section 7.4, Customer shall provide Duke Energy with thirty (30) calendar days' prior notice of Customer's vacating of the property where the Charging Equipment has been installed, even if Customer is not interested in pursuing a Permitted Assignment or Permitted Move.

7.7 Termination Fee. In the event that (i) Customer terminates this Service Agreement in accordance with Section 7.2(a) or (ii) Duke Energy terminates this Service Agreement in accordance with Section 7.2(b) or 7.2(c) if Customer fails to meet any of the Program eligibility requirements or adhere to any of Customer's obligations set forth in this Service Agreement, Customer shall pay a termination fee amounting to forty percent (40%) of the remaining aggregate EVSE Fees to be paid during the Term ("***Termination Fee***") within thirty (30) calendar days of the termination.

7.8 Effect of Termination. If either Customer or Duke Energy terminates this Service Agreement, Customer will be responsible for all applicable charges and fees including the monthly EVSE Fee through the date of termination. In the event of a termination of this Service Agreement, on the date of termination, Customer's right to use the Charging Equipment under this Service Agreement will automatically expire and Customer shall promptly make the Site available to Duke Energy and/or Duke Energy's designated third-party to access and remove the Charging Equipment from the Site. Duke Energy, in its sole discretion, may waive the Termination Fee if it so desires. If this Service Agreement shall be terminated pursuant to this Article 7, all further obligations of the parties under this Service Agreement (other than the provisions which by their terms are intended to survive the expiration or termination of this Service Agreement including Sections 14.4, 14.6, 14.7, 14.8 and this Article 7) shall be terminated without further liability of any party to the other party (other than the payment of the Termination Fee if applicable or as otherwise expressly set forth herein) and the exercise of such right of termination will not be an election of remedies; provided, however, that nothing herein shall relieve any party from liability for its breach of the terms or provisions of this Service Agreement.

8. **Charging Equipment and Network**

8.1 Ownership. While Customer participates in the Program, Duke Energy will own and maintain the Charging Equipment and network seat (if applicable). Ownership of and title to the Charging Equipment shall remain with Duke Energy at all times, and Customer is therefore not permitted to make any alterations, changes, or modifications to the Charging Equipment without first securing prior written permission from Duke Energy. Customer will not sell or allow the Charging Equipment to become subject to any lien, security interest or other claim asserted by any of Customer's creditors, and any sale of the Site shall not include the Charging Equipment.

8.2 Branding. Subject to Section 8.3, Customer is permitted to customize the Charging Equipment at Customer's expense to the extent offered by the Charging Equipment manufacturer. Customer shall arrange any such branding directly with the manufacturer and pay any costs or fees for such branding. Any such costs and fees will not appear on Customer's Duke Energy electric bill or be included in any item set forth therein and shall be paid by Customer directly to the Charging Equipment manufacturer.

8.3 Advertising. Customer shall be permitted to promote and advertise its participation in the Program; provided, however, Duke Energy reserves the right to review and approve any and all advertising, marketing, co-branding or promotional copy or materials developed or used by Customer which references Customer's participation in the Program prior to Customer's use of such copy or materials. Approval shall be granted by Duke Energy, unless Duke Energy in its sole discretion, determines that the copy or materials are misleading, in error, or fail to meet the requirements of the Program terms and conditions or is not in Duke Energy's best interest. In the event that Duke Energy does not approve any such copy or materials, Customer agrees to not use any such copy or materials or, if already in circulation, remove such copy or materials from circulation. Customer shall not use, reproduce or display any trademark owned or held by Duke Energy or any of its affiliates without the prior written consent of Duke Energy.

8.4 Software Updates. Customer is required to keep any network or software versions up to date as released and requested by the manufacturer. Duke Energy will not be responsible for these software upgrades while the unit is installed on Customer property.

8.5 Incentives. To the extent the installation, ownership, use and operation of the Charging Equipment generates any tax credits or other incentives, such credits and incentives shall be the sole property of and shall inure to the benefit of Duke Energy for the period for which it owns the Charging Equipment. If, for any reason, any such credits are not received by Duke Energy, but are instead received by Customer, Customer agrees to promptly pay the dollar amount of any such credits to Duke Energy.

8.6 Repair. In the event the Charging Equipment fails to operate or otherwise requires repair, Customer agrees to promptly notify Duke Energy. Duke Energy agrees to use commercially reasonable efforts to pursue any applicable warranty claim that may exist due to the Charging Equipment's failure to operate or need of repair.

8.7 Network Change. Customer agrees not to request a network change within one (1) calendar year following the Activation Date. In the case of a network change consented to in writing by Duke Energy, unless Duke Energy and Customer agree in writing otherwise, Customer shall pay all of Duke Energy's reasonable costs and expenses incurred to change the charging network. The Parties hereby agree that any change in network will not effect the Term.

9. **Cooperation**

9.1 General Cooperation. Successful implementation of the Program depends on Customer's cooperation with Duke Energy's service technicians, equipment providers, and Duke Energy and their respective agents and affiliates. To help Duke Energy to continue to improve the Program and its EV offerings, Duke Energy needs to be able to easily communicate with Customer and solicit Customer's feedback. By applying for the Program, Customer consents to receive communications from Duke Energy and participate in surveys relating to the Program and other service offerings in electronic form sent to the email address Customer provided. Customer is solely responsible for ensuring that the Charging Equipment is accessed and used only by Customer or individuals who Customer authorizes to use the Charging Equipment.

9.2 Disclosure to Installers. By applying for the Program, Customer consents to Duke Energy's disclosure of Customer's name, address, telephone number, EV charging data, and any EV charging or electrical usage patterns concerning the Program with any of Duke Energy's service technicians as reasonably necessary for Duke Energy to perform its obligations under this Service Agreement.

9.3 Future Programs. Customer may be eligible for participation in future programs or initiatives offered by Duke Energy, including certain managed charging offerings.

10. **Duke Energy's Disclosure and Use of Charging Equipment Data**

Customer consents and acknowledges that Duke Energy owns and may use any and all of the data recorded through the Charging Equipment for any purpose consistent with applicable laws, including Commission rules. Such purposes include administering and providing Customer services through the Program, supporting regulatory filings (in accordance with customer data privacy requirements), responding to discovery or audit requests from the Commission, and developing regulated programs or offerings.

11. **Tariff**

In addition to this Service Agreement, the terms, conditions, and rates provided in the Tariff will apply to the Customer's participation in the Program. Duke Energy is regulated by the applicable state utility commission (the "***Commission***"), and the Commission has the authority to establish just and reasonable rates, terms, and conditions between Duke Energy and its customers. It is possible that during the Term, there will be a change to the Tariff that could conflict or be inconsistent with the terms of this Service Agreement. If there is any conflict or inconsistency between this Service Agreement and the Tariff, the Tariff governs.

12. **Insurance Coverage**

Throughout the Term, Customer shall procure and maintain in full force and effect a standard all risk property insurance policy with amounts sufficient to cover the full replacement cost of the Site. Duke Energy and Customer hereby waive any and all claims and rights of action (by way of subrogation or otherwise) against the other (and against any insurance company insuring the other party) which may hereafter arise on account of bodily injury or damage to the Charging Equipment or to the Site, resulting from any fire, or other perils or claims of the kind covered by standard all risk property insurance policies with extended coverage (Causes of Loss Special Form) regardless of whether or not, or in what amounts, such insurance is now or hereafter carried by the parties, or either of them. Customer agrees that Duke Energy may self-insure against any loss or damage which could be covered by a commercial general public liability insurance policy and or a property policy. **Customer will give written notice of this mutual waiver to each insurance company which issues insurance policies to Customer with respect to the items covered by this waiver, and shall have Customer's insurance policies properly endorsed, if necessary, to prevent the invalidation of any of the coverage provided by such insurance policies by reason of such waiver.**

If there is a claim related to the services under the Agreement, Customer shall, upon Duke Energy's request, provide a copy of any or all of its required insurance policies, including endorsements in which Duke Energy is included as an additional insured.

13. **Limited Warranty**

Duke Energy warrants that Work performed by Duke Energy's service technicians will be performed in a safe and professional manner in accordance with all applicable laws. In the event that any Work performed is found to be defective and Customer notifies Duke Energy of such defect, Duke Energy shall repair or replace such defective Work at Duke Energy's expense. **THE REPAIR OR REPLACEMENT OF SUCH DEFECTIVE WORK IS CUSTOMER'S SOLE AND EXCLUSIVE REMEDY, AND DUKE ENERGY'S ENTIRE LIABILITY UNDER THIS SERVICE AGREEMENT FOR ANY FAILURE OF DUKE ENERGY TO COMPLY WITH DUKE ENERGY'S OBLIGATIONS. OTHER THAN ITS OBLIGATION TO MAKE REASONABLE EFFORTS TO MAINTAIN THE CHARGING EQUIPMENT WHILE CUSTOMER PARTICIPATES IN THE PROGRAM, DUKE ENERGY IS NOT RESPONSIBLE FOR AND MAKES NO REPRESENTATIONS OR WARRANTIES WITH RESPECT TO THE CHARGING EQUIPMENT OR THAT THE CHARGING EQUIPMENT WILL OPERATE ERROR FREE, AND DUKE ENERGY HEREBY DISCLAIMS ANY RESPONSIBILITY OR WARRANTY FOR THE CHARGING EQUIPMENT. EXCEPT AS EXPRESSLY SET FORTH IN THIS ARTICLE 13, DUKE ENERGY MAKES NO REPRESENTATIONS OR WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED. TO THE FULLEST EXTENT PERMITTED BY LAW, AND UNLESS OTHERWISE SPECIFIED IN WRITING, DUKE ENERGY DISCLAIMS ALL WARRANTIES, EXPRESS OR IMPLIED, AS TO THE WORK OR CHARGING EQUIPMENT, INCLUDING ANY IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE OR NONINFRINGEMENT OF INTELLECTUAL PROPERTY RIGHTS.**

14. **Other Terms and Conditions**

14.1 Indemnification. To the extent permitted by applicable law (but except to the extent excluded by the terms of this Service Agreement), each party shall indemnify and hold the other party harmless against any third party claim of liability or loss from bodily injury (including mental or emotional distress or death of any person) or property damage (whether real, personal, tangible or intangible including without limitation real or personal property of any third party, the Charging Equipment and any associated equipment hardware) resulting from or arising out of the use of the Site by the party, its servants or agents ("***Losses***"), except however, such claims or damages as may be due to or caused by the negligence or willful misconduct of the other party, its servants, or its agents.

14.2 Cap. The maximum amount that either party shall be required to pay in aggregate in respect to all Losses shall not exceed two times the EVSE Fee paid in one (1) year ("***Cap***"); provided, however, that the Cap shall not apply with respect to (i) the Termination Fee (or claims, or causes of action, relating to a failure of Customer to pay the Termination Fee), or (ii) claims of, or causes of action from, intentional fraud or willful misconduct of the indemnifying party and any Losses incurred as a result of any such claims or causes of action.

14.3 Limitation of Liability. Notwithstanding anything herein to the contrary, under no circumstances or legal theory, whether arising in contract, tort, strict liability, warranty, infringement, or otherwise, shall either party be liable to the other party or any other person or entity for any indirect, consequential, secondary, incidental, special, reliance, exemplary, or punitive damages, including without limitation any such damages in connection with: (i) any property damage (real, personal, tangible, or intangible) or personal injury (including mental or emotional distress) arising from or alleged to have arisen under this Service Agreement; (ii) any damages arising or alleged to have arisen from any electrical malfunction or the repair or replacement of such malfunctioning items; or (iii) any environmental claims, damage, or causes of action.

14.4 Non-Reliance. Under no circumstances will Duke Energy or its agents be held liable to Customer or any other person or entity for matters involving the purchase, lease, use, non-use, or devaluation of any EV or any other vehicle of any nature, or any Charging Equipment or associated equipment infrastructure when applicable codes or standards prohibit the installation or use of such vehicle, Charging Equipment or infrastructure. Duke Energy will not pay for any costs incurred or damages sustained by Customer for purchasing any vehicle or equipment or otherwise in reliance upon Duke Energy being able to provide the Charging Equipment. In no event will Duke Energy be liable to Customer for any claims, expenses, losses, damages, or lawsuits arising out of any interruptions or disturbances in electric service.

14.5 Assignment. Duke Energy may assign this Service Agreement or any benefit, interest, right or cause of action arising under this Service Agreement to any person without restriction. Customer shall not assign this Service Agreement except with the prior written consent of Duke Energy, which Duke Energy may withhold in its sole discretion. Any assignment without Duke Energy's consent shall be null and void.

14.6 Governing Law. This Service Agreement shall be governed by the laws of the state where the Site is located, without reference to its conflict-of-law principles.

14.7 Waiver. Duke Energy's failure to insist on performance of any of the terms and conditions herein or to exercise any right or privilege or Duke Energy's waiver of any breach hereunder shall not thereafter waive any of Duke Energy's rights or privileges under this Service Agreement or at law. Any waiver of any specific breach shall be effective only if given expressly by Duke Energy in writing.

14.8 Entire Agreement. This Service Agreement and any tariffs and/or rate schedules applicable to Customer's service, embodies the entire agreement between Customer and Duke Energy. The parties shall not be bound by or liable for any other statement, writing, representation, promise, inducement, or understanding. No changes, modifications, or amendments of any terms and conditions of this Service Agreement are valid or binding unless agreed to by the parties in writing and signed by the parties.

14.9 Power Outages. Customer acknowledges and understands that power outages may occur, and therefore Charging Equipment under this Service Agreement may not be operable during such outage. The Parties acknowledge and agree that Duke Energy does not guarantee continuity of service to the Charging Equipment and is not responsible or liable for interruption, failure, or defect in the supply or character of electricity furnished to the Charging Equipment.

14.10 Accessibility Requirements. Customer understands and accepts that Charging Equipment that are publicly accessible shall comply with the Americans with Disabilities Act ("***ADA***") and any applicable Kentucky building standards. Customer understands and accepts that such standards may impact parking layouts and potentially change the number of non-accessible parking spaces available. Customer understands and accepts that changes to initial design representations may occur during the design, construction and operational phases of the Program and may be dictated by design constraints, by law or regulation or by local jurisdictional authorities. Customer shall be responsible for any construction upgrades to the Site required in order for the property to be ADA complaint and hereby agrees that Duke Energy will not be responsible for any construction upgrades required for the Charging Equipment or the Site to be ADA compliant, including but not limited to, the construction of ADA-compliant ramps or the inclusion of certain signage or paint markings.

15. **Questions**

If Customer has questions regarding these terms or the Program, or is required to provide Duke Energy notice pursuant to this Service Agreement, please contact Duke Energy using the information and instructions on the Program Website.

CHARGER SOLUTION PROGRAM

EXHIBIT A - STATEMENT OF WORK

Application Submitted Date: xx/xxx/xxxx
Business Name:
DE Account Number:
Address
City, State, Zip
Site address
Site City, Site State, Site Zip

This Statement of Work includes the following attachments:

Application dated: xx/xx/xxxx
Sketch of proposed location (submitted with application) dated: xx/xx/xxxx
Site Plan dated: xx/xx/xxxx
Single Line Drawing dated: xx/xx/xxxx
Site Readiness Survey Part A, submitted by customer dated: xx/xx/xx
Site Readiness Survey Part B submitted by Program Installation Contractor dated: xx/xx/xxxx

The following parties agree to the Statement of Work provided in the above attachments

Customer:	Duke Energy:
Print Name ______________________________	Print Name ______________________________
Signature ______________________________	Signature ______________________________
Title ______________________________	Title ______________________________
Date ______________________________	Date ______________________________

Charger Solution Program Service Agreement

Duke Energy Indiana, LLC ("***Duke Energy***") is excited to offer the Charger Solution Program known as "Charger Solution" (the "***Program***") established in accordance with the EVSE Tariff (the "***Tariff***") to its residential electric customers (each, a "***Customer***"). Customer's participation in the Program is subject to the terms and conditions of this Charger Solution Program Service Agreement (the "***Service Agreement***").

1. Charger Solution Program Overview

1.1 Program Overview. Duke Energy is offering eligible Customers an opportunity to participate in a worry-free and affordable program to have electric vehicle ("***EV***") chargers at their home for a fee on their monthly electric bill. Under the Program, Duke Energy will provide Customer a level 2 EV charger selected by the Customer (the "***Charging Equipment***") from Duke Energy's list of pre-qualified EV charger options, all of which meet the applicable technical and safety standards considered by Duke Energy. Such Charging Equipment will be installed at Customer's electric service address. A list of the approved charging equipment may be found on Duke Energy's website for the Program located at: https://www.duke-energy.com/energy-education/electric-vehicles (the "***Program Website***"). In addition, Customer will be able to select various extra equipment to use in connection with its selected Charging Equipment (such selected equipment, the "***Extra Facilities***"), the cost of which will not be included in the EVSE Fee (as defined below) as further set forth in Article 6.

1.2 Installation. Once Customer selects Customer's Charging Equipment and is successfully enrolled in the Program in accordance with Article 3, Duke Energy will arrange to have one of Duke Energy's third party service technicians install the Charging Equipment and Extra Facilities, if necessary, at a time convenient for Customer during working hours between 7:00 A.M. local time and 7:00 PM local time ("***Working Hours***").

1.3 General Ownership and Maintenance. Once installed, Duke Energy will continue to own and maintain the Charging Equipment and Extra Facilities. Subject to the terms and conditions set forth herein, the costs of the Charging Equipment, installation, ongoing maintenance, and annual software networking fees (if any) will be included on Customer's monthly electric bill, as a convenient fee (such fee, the "***EVSE Fee***"). For the avoidance of doubt, the EVSE Fee shall not include charges for any Extra Facilities or any necessary excess facilities associated with Duke Energy's service regulations and/or line extension deposit requirements, electrical panel or wiring make-ready costs, costs for work on either side of the meter, non-standard equipment, after Working Hours service costs, costs for electricity usage or any other costs or expenses which Customer elects to incur which are expressly indicated in this Service Agreement or any other Program materials as being in addition to or outside of the EVSE Fee. Internet connectivity, arranged by Customer and at Customer's expense, may be required for Customer to participate in certain other Duke Energy programs that may be offered in conjunction with other Duke Energy tariffs but is not required to participate in this Program.

2. Eligibility and Availability

To be eligible to participate in the Program, Customer must:

- agree to the terms and conditions contained in this Service Agreement via submission of Customer's application to participate in the Program;
- be an electric customer in Duke Energy's service territory and have an active Duke Energy account that receives electric service;

- request installation of the Charging Equipment in a location that is (i) readily accessible in order to support installation and maintenance of the Charging Equipment, and (ii) meets the "Site Readiness" requirements (as specified on the Program Website);

- agree to cooperate with Duke Energy and provide Duke Energy with additional information or documents, including pictures of the Site (as defined below) or meter, that Duke Energy reasonably requires to determine Customer's eligibility to participate in the Program; and

- own a detached property; otherwise, if such Customer is renting, Customer's property must have separately metered service, and Customer must: (i) obtain the building owner's written consent for Customer to participate in the Program, and (ii) agree that Customer's participation in the Program shall be terminated in accordance with Article 7 if the building owner revokes such consent.

3. **Enrollment Process**

3.1 Application. To enroll in the Program, Customer will need to complete the application found on the Program Website. Once Duke Energy has received Customer's complete application, Duke Energy will send Customer an email confirming (or declining) Customer's eligibility for the Program, subject to further review of the Site. The date the Site suitability has been confirmed (which may include a Site visit) will be considered Customer's "***Enrollment Date***".

3.2 Automatic Termination. If, at any time prior to the Activation Date (as defined below), Duke Energy determines that Customer is actually ineligible for the Program or Duke Energy determines that it is not reasonably feasible to offer service or maintain Charging Equipment at the Site, Duke Energy shall notify Customer of the same and this Service Agreement will be deemed automatically terminated and will be of no further force or effect ("***Automatic Termination***").

3.3 Activation Date. Once the Charging Equipment has been installed at Customer's property (the "***Site***") (such date of installation, the "***Activation Date***"), Customer can start using the Charging Equipment located at the Site. Customer will receive their first bill in connection with the Program in the first billing period following the Activation Date. This first bill may be prorated depending on the Activation Date and Customer's billing cycle.

4. **Charging Equipment Installation and Maintenance**

Following the Enrollment Date, Duke Energy will, through its network of third party service technicians, provide, install, maintain, repair or replace the Charging Equipment (collectively the "***Work***") on the Site. The Site will be identified by Customer in its application to participate in the Program and will be an enclosed garage area or other area approved by Duke Energy. Duke Energy, in its sole discretion, shall have the right to repair, modify, or replace the Charging Equipment at any time during Customer's Term (as defined below). If safety, reliability, or access negatively affects delivery of service under this Service Agreement, then Duke Energy may withhold or discontinue service as it deems necessary. Duke Energy will use commercially reasonable efforts to maintain the Charging Equipment in working order, and will attempt to provide Customer reasonable advance notice of any required maintenance of the Charging Equipment. Duke Energy, or its third party service technicians, will coordinate with Customer to schedule maintenance Work during Working Hours. For an additional fee, maintenance may be scheduled after Working Hours, contingent on availability of an appropriate third party service technician, and such additional fee will be itemized on Customer's bill separate and distinct from the EVSE Fee. Customer understands that if Duke Energy is unable to arrange for maintenance Work to be completed at a mutually agreeable time, the Charging Equipment may not function and Customer may not be able to charge Customer's EV at the Site.

5. **Customer's Charging Equipment Obligations and Duties**

5.1 Access. During the Term (as defined below), Customer agrees to grant Duke Energy the necessary access to the Site and sufficient space to locate the Charging Equipment at the Site as may be deemed necessary or desirable by Duke Energy to perform the Work. Installations must conform to Duke Energy's specifications.

5.2 Customer Maintenance. During the Term, Customer will maintain the area surrounding the Charging Equipment and generally inspect the Charging Equipment and area surrounding the Charging Equipment and will promptly notify Duke Energy of any problems related to the Charging Equipment of which Customer becomes aware. For the avoidance of doubt, Customer is not responsible for the ongoing scheduled maintenance of the Charging Equipment.

5.3 Use of Charging Equipment. Customer will use the Charging Equipment only as specified by the Charging Equipment manufacturer and will be responsible for any damage caused to the Charging Equipment due to Customer's misuse, neglect, vandalism, or abuse. Customer agrees to remedy minor issues that do not require qualified service technicians to address, such as resetting infrequently tripped circuit breakers, reconnecting the plug and vehicle to engage charging, or resetting the network connection.

5.4 Networked Charging Equipment. For networked Charging Equipment, Customer shall provide and be responsible for maintaining communication access through wi-fi, cellular or other communications capabilities and any such costs of maintaining such communication access shall not be included in the EVSE Fee.

5.5 Third Party Access. Customer agrees to provide access and assistance to Duke Energy and/or Duke Energy's designated third-parties (including, without limitation, Duke Energy's network of third party service technicians) to facilitate random Charging Equipment testing. Such cooperation may include, but is not limited to, periodic inspection of the Charging Equipment and the addition of monitoring hardware or software at Duke Energy's expense.

6. **Applicable Charges**

6.1 Charges. Customer's participation in the Program will require Customer to pay for all electricity usage each month separate from the EVSE Fee. Customer will also be charged a monthly EVSE Fee for the Charging Equipment, the installation and maintenance services provided by Duke Energy and/or Duke Energy's designee, and any applicable network fees. The applicable monthly EVSE Fee is listed in the Tariff. In addition, Customer may elect to obtain certain Extra Facilities which shall not be included in the EVSE Fee. For Customer's convenience, Customer's monthly EVSE Fee and costs for Extra Facilities and any after Working Hours maintenance will each appear on Customer's Duke Energy electric bill as separate line items. Duke Energy will not provide a breakdown of the EVSE Fee, other than what is legally required. For the avoidance of doubt, Customer shall also be responsible for any applicable taxes. As set forth in Section 8.3, Duke Energy may provide Customer with a credit to its Duke Energy electric bill in certain instances.

6.2 Deposit. Duke Energy may also, at its option, require a deposit not to exceed an aggregate amount of two (2) months of the EVSE Fees to be charged during the Term, which shall be applied to Customer's Duke Energy electric account after the first anniversary of the Activation Date, provided Customer has met all of Customer's obligations under this Service Agreement.

7. **Term and Termination**

7.1 Term. This Service Agreement shall be effective as of the Enrollment Date. The term shall commence on the Enrollment Date and will continue for forty-eight months from the Activation Date, or until terminated in accordance with this Article 7 (the " ***Term***"). At the end of the Term, unless this Service Agreement has already been terminated in accordance with this Article 7, Customer shall be given the option to: (i) extend the Term or enter into a new service agreement, at Duke Energy's sole discretion, (ii) assign the Charging Equipment to another party (with the written consent of Duke Energy, which Duke Energy may withhold in its sole discretion), or (iii) promptly make the Site available to Duke Energy and/or Duke Energy's designated third-party to access and remove the Charging Equipment from the Site.

7.2 Termination. This Service Agreement may be terminated at any time:

(a) subject to payment of the Termination Fee (as defined below), by Customer for any reason by providing Duke Energy thirty (30) calendar days of prior written notice of such termination;

(b) by Duke Energy for any reason by providing Customer thirty (30) calendar days prior written notice of such termination;

(c) by Duke Energy immediately if: (i) Customer fails to meet any of the Program eligibility requirements or adhere to any of Customer's obligations set forth in this Service Agreement in a manner that would make it unsafe for Customer to continue to participate in the Program, (ii) Customer rents the property where the Site is located and the property owner revokes its consent to Customer's participation in the Program, or (iii) Duke Energy is required to terminate the Program by the Commission (as defined below), and providing thirty (30) calendar days' notice would not be practicable or permitted by the Commission or other laws.

7.3 Automatic Termination. This Service Agreement shall be deemed terminated automatically:

(a) in the event an Automatic Termination occurs in accordance with Section 3.2; or

(b) in the event Customer sells, or no longer resides at, the property where the Charging Equipment has been installed; provided, however, with Duke Energy's written consent, which Duke Energy may withhold at its sole discretion, Customer may seek (i) to assign the Charging Equipment and all rights and obligations hereunder to an existing or new property owner or tenant of the Site, provided such proposed transferee is a Duke Energy electric customer (a "***Permitted Assignment***"), or (ii) to move the Charging Equipment to a new property for a mutually agreed cost (a "***Permitted Move***).

7.4 Permitted Assignment; Permitted Move. Customer must submit a request for any Permitted Assignment or Permitted Move to Duke Energy as soon as practical but at least thirty (30) calendar days prior to the requested date of such Permitted Assignment or Permitted Move and, in the case of a Permitted Assignment, shall have the proposed transferee promptly contact Duke Energy. In the case of a Permitted Assignment or Permitted Move which is consented to in writing by Duke Energy, unless Duke Energy and Customer agree in writing otherwise, Customer shall pay all of Duke Energy's reasonable costs and expenses to move the Charging Equipment to a new property or assign the Charging Equipment and all rights and obligations hereunder to a new person, as applicable.

7.5 Hardware Change. Customer may request a change in charging equipment hardware during the Term by submitting a request to Duke Energy at least thirty (30) calendar days prior to Customer's preferred change in equipment. Customer shall pay all of Duke Energy's reasonable costs and expenses to remove the existing Charging Equipment and install the new charging equipment requested by Customer. Duke Energy and Customer will then terminate this Service Agreement and enter into a new Charger Solution Program Service Agreement for the new charging equipment hardware at the rate associated with the applicable charging equipment and associated network at the time of installation of the new charging equipment hardware.

7.6 Notice of Vacation. Notwithstanding anything to the contrary in Section 7.4, Customer shall provide Duke Energy with thirty (30) calendar days' prior notice of Customer's vacating of the property where the Charging Equipment has been installed, even if Customer is not interested in pursuing a Permitted Assignment or Permitted Move.

7.7 Termination Fee. In the event that (i) Customer terminates this Service Agreement in accordance with Section 7.2(a) or (ii) Duke Energy terminates this Service Agreement in accordance with Section 7.2(b) or 7.2(c) if Customer fails to meet any of the Program eligibility requirements or adhere to any of Customer's obligations set forth in this Service Agreement, Customer shall pay a termination fee amounting to forty percent (40%) of the remaining aggregate EVSE Fees to be paid during the Term ("***Termination Fee***") within thirty (30) calendar days of the termination.

7.8 Effect of Termination. If either Customer or Duke Energy terminates this Service Agreement, Customer will be responsible for all applicable charges and fees including the monthly EVSE Fee through the date of termination. In the event of a termination of this Service Agreement, on the date of termination, Customer's right to use the Charging Equipment under this Service Agreement will automatically expire and Customer shall promptly make the Site available to Duke Energy and/or Duke Energy's designated third-party to access and remove the Charging Equipment from the Site. Duke Energy, in its sole discretion, may waive the Termination Fee if it so desires. If this Service Agreement shall be terminated pursuant to this Article 7, all further obligations of the parties under this Service Agreement (other than the provisions which by their terms are intended to survive the expiration or termination of this Service Agreement including Sections 14.4, 14.6, 14.7, 14.8 and this Article 7) shall be terminated without further liability of any party to the other party (other than the payment of the Termination Fee if applicable or as otherwise expressly set forth herein) and the exercise of such right of termination will not be an election of remedies; provided, however, that nothing herein shall relieve any party from liability for its breach of the terms or provisions of this Service Agreement.

8. Charging Equipment and Network

8.1 Ownership. While Customer participates in the Program, Duke Energy will own and maintain the Charging Equipment and network seat (if applicable). Ownership of and title to the Charging Equipment shall remain with Duke Energy at all times, and Customer is therefore not permitted to make any alterations, changes, or modifications to the Charging Equipment without first securing prior written permission from Duke Energy. Customer will not sell or allow the Charging Equipment to become subject to any lien, security interest or other claim asserted by any of Customer's creditors, and any sale of the Site shall not include the Charging Equipment.

8.2 Software Updates. Customer is required to keep any network or software versions up to date as released and requested by the manufacturer. Duke Energy will not be responsible for these software upgrades while the unit is installed on Customer property.

8.3 Incentives. To the extent the installation, ownership, use and operation of the Charging Equipment generates any tax credits or other incentives, such credits and incentives shall be the sole property of and shall inure to the benefit of Duke Energy for the period for which it owns the Charging

Equipment. If, for any reason, any such credits are not received by Duke Energy, but are instead received by Customer, Customer agrees to promptly pay the dollar amount of any such credits to Duke Energy.

8.4 Repair. In the event the Charging Equipment fails to operate or otherwise requires repair, Customer agrees to promptly notify Duke Energy. Duke Energy agrees to use commercially reasonable efforts to pursue any applicable warranty claim that may exist due to the Charging Equipment's failure to operate or need of repair.

8.5 Network Change . Customer agrees not to request a network change within one (1) calendar year following the Activation Date. In the case of a network change consented to in writing by Duke Energy, unless Duke Energy and Customer agree in writing otherwise, Customer shall pay all of Duke Energy's reasonable costs and expenses incurred to change the charging network. The Parties hereby agree that any change in network will not effect the Term.

9. **Cooperation**

9.1 General Cooperation. Successful implementation of the Program depends on Customer's cooperation with Duke Energy's service technicians, equipment providers, and Duke Energy and their respective agents and affiliates. To help Duke Energy to continue to improve the Program and its EV offerings, Duke Energy needs to be able to easily communicate with Customer and solicit Customer's feedback. By applying for the Program, Customer consents to receive communications from Duke Energy and participate in surveys relating to the Program and other service offerings in electronic form sent to the email address Customer provided. Customer is solely responsible for ensuring that the Charging Equipment is accessed and used only by Customer or individuals who Customer authorizes to use the Charging Equipment.

9.2 Disclosure to Installers. By applying for the Program, Customer consents to Duke Energy's disclosure of Customer's name, address, telephone number, EV charging data, and any EV charging or electrical usage patterns concerning the Program with any of Duke Energy's service technicians as reasonably necessary for Duke Energy to perform its obligations under this Service Agreement.

9.3 Future Programs. Customer may be eligible for participation in future programs or initiatives offered by Duke Energy, including certain managed charging offerings.

10. **Duke Energy's Disclosure and Use of Charging Equipment Data**

Customer consents and acknowledges that Duke Energy owns and may use any and all of the data recorded through the Charging Equipment for any purpose consistent with applicable laws, including Commission rules. Such purposes include administering and providing Customer services through the Program, supporting regulatory filings (in accordance with customer data privacy requirements), responding to discovery or audit requests from the Commission, and developing regulated programs or offerings.

11. **Tariff**

In addition to this Service Agreement, the terms, conditions, and rates provided in the Tariff will apply to the Customer's participation in the Program. Duke Energy is regulated by the applicable state utility commission (the "***Commission***"), and the Commission has the authority to establish just and reasonable rates, terms, and conditions between Duke Energy and its customers. It is possible that during the Term, there will be a change to the Tariff that could conflict or be inconsistent with the terms of this Service Agreement. If there is any conflict or inconsistency between this Service Agreement and the Tariff, the Tariff governs.

12. Insurance Coverage

Throughout the Term, Customer shall procure and maintain in full force and effect a standard fire and homeowner's insurance policy with amounts sufficient to cover the full replacement cost of the Site. Duke Energy and Customer hereby waive any and all claims and rights of action (by way of subrogation or otherwise) against the other (and against any insurance company insuring the other party) which may hereafter arise on account of bodily injury or damage to the Charging Equipment or to the Site, resulting from any fire, or other perils or claims of the kind covered by standard fire and homeowner's insurance policies with extended coverage (Causes of Loss Special Form) regardless of whether or not, or in what amounts, such insurance is now or hereafter carried by the parties, or either of them. Customer agrees that Duke Energy may self-insure against any loss or damage which could be covered by a commercial general public liability insurance policy and or a property policy. **Customer will give written notice of this mutual waiver to each insurance company which issues insurance policies to Customer with respect to the items covered by this waiver, and shall have Customer's insurance policies properly endorsed, if necessary, to prevent the invalidation of any of the coverage provided by such insurance policies by reason of such waiver.**

If there is a claim related to the services under the Agreement, Customer shall, upon Duke Energy's request, provide a copy of any or all of its required insurance policies, including endorsements in which Duke Energy is included as an additional insured.

13. Limited Warranty

Duke Energy warrants that Work performed by Duke Energy's service technicians will be performed in a safe and professional manner in accordance with all applicable laws. In the event that any Work performed is found to be defective and Customer notifies Duke Energy of such defect, Duke Energy shall repair or replace such defective Work at Duke Energy's expense. **THE REPAIR OR REPLACEMENT OF SUCH DEFECTIVE WORK IS CUSTOMER'S SOLE AND EXCLUSIVE REMEDY, AND DUKE ENERGY'S ENTIRE LIABILITY UNDER THIS SERVICE AGREEMENT FOR ANY FAILURE OF DUKE ENERGY TO COMPLY WITH DUKE ENERGY'S OBLIGATIONS. OTHER THAN ITS OBLIGATION TO MAKE REASONABLE EFFORTS TO MAINTAIN THE CHARGING EQUIPMENT WHILE CUSTOMER PARTICIPATES IN THE PROGRAM, DUKE ENERGY IS NOT RESPONSIBLE FOR AND MAKES NO REPRESENTATIONS OR WARRANTIES WITH RESPECT TO THE CHARGING EQUIPMENT OR THAT THE CHARGING EQUIPMENT WILL OPERATE ERROR FREE, AND DUKE ENERGY HEREBY DISCLAIMS ANY RESPONSIBILITY OR WARRANTY FOR THE CHARGING EQUIPMENT. EXCEPT AS EXPRESSLY SET FORTH IN THIS <u>ARTICLE 13</u>, DUKE ENERGY MAKES NO REPRESENTATIONS OR WARRANTIES OF ANY KIND, EXPRESS OR IMPLIED. TO THE FULLEST EXTENT PERMITTED BY LAW, AND UNLESS OTHERWISE SPECIFIED IN WRITING, DUKE ENERGY DISCLAIMS ALL WARRANTIES, EXPRESS OR IMPLIED, AS TO THE WORK OR CHARGING EQUIPMENT, INCLUDING ANY IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE OR NONINFRINGEMENT OF INTELLECTUAL PROPERTY RIGHTS.**

14. Other Terms and Conditions

14.1 <u>Indemnification</u>. To the extent permitted by applicable law (but except to the extent excluded by the terms of this Service Agreement), each party shall indemnify and hold the other party harmless against any third party claim of liability or loss from bodily injury (including mental or emotional distress or death of any person) or property damage (whether real, personal, tangible or intangible including without limitation real or personal property of any third party, the Charging Equipment and any associated equipment hardware) resulting from or arising out of the use of the Site by the party, its servants or agents ("***Losses***"), except however, such claims or damages as may be due to or caused by the negligence or willful misconduct of the other party, its servants, or its agents.

14.2 Cap. The maximum amount that either party shall be required to pay in aggregate in respect to all Losses shall not exceed two times the EVSE Fee paid in one (1) year ("***Cap***"); provided, however, that the Cap shall not apply with respect to (i) the Termination Fee (or claims, or causes of action, relating to a failure of Customer to pay the Termination Fee), or (ii) claims of, or causes of action from, intentional fraud or willful misconduct of the indemnifying party and any Losses incurred as a result of any such claims or causes of action.

14.3 Limitation of Liability. Notwithstanding anything herein to the contrary, under no circumstances or legal theory, whether arising in contract, tort, strict liability, warranty, infringement, or otherwise, shall either party be liable to the other party or any other person or entity for any indirect, consequential, secondary, incidental, special, reliance, exemplary, or punitive damages, including without limitation any such damages in connection with: (i) any property damage (real, personal, tangible, or intangible) or personal injury (including mental or emotional distress) arising from or alleged to have arisen under this Service Agreement; (ii) any damages arising or alleged to have arisen from any electrical malfunction or the repair or replacement of such malfunctioning items; or (iii) any environmental claims, damage, or causes of action.

14.4 Non-Reliance. Under no circumstances will Duke Energy or its agents be held liable to Customer or any other person or entity for matters involving the purchase, lease, use, non-use, or devaluation of any EV or any other vehicle of any nature, or any Charging Equipment or associated equipment infrastructure when applicable codes or standards prohibit the installation or use of such vehicle, Charging Equipment or infrastructure. Duke Energy will not pay for any costs incurred or damages sustained by Customer for purchasing any vehicle or equipment or otherwise in reliance upon Duke Energy being able to provide the Charging Equipment. In no event will Duke Energy be liable to Customer for any claims, expenses, losses, damages, or lawsuits arising out of any interruptions or disturbances in electric service.

14.5 Assignment. Duke Energy may assign this Service Agreement or any benefit, interest, right or cause of action arising under this Service Agreement to any person without restriction. Customer shall not assign this Service Agreement except with the prior written consent of Duke Energy, which Duke Energy may withhold in its sole discretion. Any assignment without Duke Energy's consent shall be null and void.

14.6 Governing Law. This Service Agreement shall be governed by the laws of the state where the Site is located, without reference to its conflict-of-law principles.

14.7 Waiver. Duke Energy's failure to insist on performance of any of the terms and conditions herein or to exercise any right or privilege or Duke Energy's waiver of any breach hereunder shall not thereafter waive any of Duke Energy's rights or privileges under this Service Agreement or at law. Any waiver of any specific breach shall be effective only if given expressly by Duke Energy in writing.

14.8 Entire Agreement. This Service Agreement and any tariffs and/or rate schedules applicable to Customer's service, embodies the entire agreement between Customer and Duke Energy. The parties shall not be bound by or liable for any other statement, writing, representation, promise, inducement, or understanding. No changes, modifications, or amendments of any terms and conditions of this Service Agreement are valid or binding unless agreed to by the parties in writing and signed by the parties.

14.9 Power Outages. Customer acknowledges and understands that power outages may occur, and therefore Charging Equipment under this Service Agreement may not be operable during such outage. The Parties acknowledge and agree that Duke Energy does not guarantee continuity of service to the Charging Equipment and is not responsible or liable for interruption, failure, or defect in the supply or character of electricity furnished to the Charging Equipment.

15. **Questions**

If Customer has questions regarding these terms or the Program, or is required to provide Duke Energy notice pursuant to this Service Agreement, please contact Duke Energy using the information and instructions on the Program Website.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

The Electronic Application of Duke Energy Kentucky, Inc., for: 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

PUBLIC

DIRECT TESTIMONY OF

PAUL L. HALSTEAD

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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ATTACHMENTS:

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Paul L. Halstead and my business address is 526 South Church Street, Charlotte NC, 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as Director Jurisdictional Rate Administration. DEBS provide various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science degree in Accounting from Pensacola Christian College and a Master of Business Administration degree from Liberty University. I also hold a Certified Public Accountant (CPA) license from the State of Virginia. I have over fourteen years of utility experience with roles in accounting, contract administration, business development, renewable program design, and rate design.

Q. PLEASE DESCRIBE YOUR RESPONSIBILITIES AS DIRECTOR JURISDICTIONAL RATE ADMINISTRATION.

A. I am responsible for supporting customer renewable program and associated rate design across the Duke Energy jurisdictions.

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

A. Yes.

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

A. My testimony is provided to support Duke Energy Kentucky's request for approval of its new Clean Energy Connection program structure and tariff (CEC Program). First, I briefly describe the CEC Program and its anticipated benefits to customers and the Company. I then describe the financial formula used to calculate the subscription fees and bill credits associated with the CEC Program proposal and its cost-effectiveness. My testimony presents the framework proposed which will enable continued customer engagement and development of the CEC Program.

II. DISCUSSION

A. OVERVIEW OF THE CEC PROGRAM PROPOSAL

Q. PLEASE DESCRIBE THE CEC PROGRAM.

A. The CEC Program is a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy facility(s). The CEC Program would allow Duke Energy Kentucky to satisfy increasing customer demand for renewable energy and will enable the Company to provide affordable clean energy to all its customers.

The CEC Program represents the next evolution of Duke Energy Kentucky's commitment to increasing renewable generation and providing innovative pricing solutions for our customers. The CEC program is structured to maximize the benefits to the entire Duke Energy Kentucky system and to share those benefits with non-participating customers.

The CEC Program will enable the construction of specific solar projects for the benefit of customers. The first project, following approval of the CEC Program itself and with substantial subscriptions, could come online as early as 2025. The Company will file a Certificate of Public Convenience and Necessity (CPCN) in a separate proceeding for Commission approval of that first solar project (and any subsequent CEC projects that are not otherwise determined to be an ordinary extension in the usual course of business).

Q. DO ANY OF DUKE ENERGY KENTUCKY'S SISTER UTILITIES HAVE A CEC PROGRAM ALREADY IN PLACE?

A. Yes, Duke Energy Florida has a CEC Program in place.

Q. DID THE COMPANY APPLY ANY KNOWLEDGE GAINED FROM THE FLORIDA CEC PROGRAM IN DEVELOPING DUKE ENERGY KENTUCKY'S CEC PROGRAM?

A. Yes, with our Duke Energy Florida program, we developed a software tool that enables income qualified customers to easily upload documentation of participation in any assistance program to then allow eligibility into CEC. We plan to use this same technology in this Duke Energy Kentucky program.

Q. PLEASE EXPLAIN THE UNIQUE FEATURES OF A CEC PROGRAM THAT WILL MAKE IT ATTRACTIVE AS A CUSTOMER OFFERING IN KENTUCKY?

A. Duke Energy Kentucky remains committed to designing innovative renewable energy programs for customers that maximize customer benefits. To date, the Company has two renewable opportunities to address specific customer needs.

Under the Company's GoGreen Kentucky (Rider GP) program tariff, customers are able to purchase Renewable Energy Certificates (RECs) to match all or part of, their carbon footprint in 100 kWh increments. This is a premium on the customer's bill and the RECs are not from Duke Energy resources. The Company's Green Source Advantage (Rate GSA) allows non-residential customers to pay a premium to support construction of a renewable energy resource that is dispatched into the PJM market through their utility bill. The customer receives the RECs from this asset, but the generation itself is dispatched into the PJM market and the customer receives the revenues of this asset, if any, as a credit on their bill. Under GSA, the renewable energy itself is not used to satisfy the customer's load.

The CEC Program will provide a third option for customers interested in renewable energy and contains a variety of innovations: 1) CEC is a customer centric program where all customer types have access to renewable energy without a long term commitment required; 2) it provides capacity for economic development projects focused on businesses with carbon goals, helping to keep Kentucky competitive for businesses with renewable requirements looking to move or expand to our area; 3) it includes an inclusive signup process to ensure that large customers who express interest in the program can take advantage of it; and 4) it includes a low income carve out in Kentucky with an easy enrollment process. Each of these will be discussed in more detail below.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING THE CEC PROGRAM?

A. Duke Energy Kentucky is proposing the CEC Program to meet the substantial demand from customers who are seeking expanded access to solar energy, but do not have the ability or the desire to construct it on their property.

Q. HOW DOES THE CEC PROGRAM DIFFER FROM THE GSA PROGRAM?

A. Customer feedback on Duke Energy Kentucky's GSA Program directly influenced the design of CEC. CEC enables customers with smaller electric loads to participate in CEC whereas GSA would be challenging if not impossible for these customers to find a renewable developer willing to develop a renewable facility on their behalf. CEC provides all customer groups an equal opportunity to participate in advancing renewable generation through their participation.

Q. IS THERE A DEMAND FOR THE CEC PROGRAM IN DUKE ENERGY KENTUCKY'S SERVICE TERRITORY?

A. Yes, we are aware of several business customers that have actively investigated the GSA program. There are also several business customers participating in our CEC program in Florida that have locations in Kentucky that Duke Energy Kentucky believes would have strong interest in this new program.

Q. HOW WILL DUKE ENERGY KENTUCKY MARKET THE CEC PROGRAM TO CUSTOMERS?

A. Duke Energy Kentucky will market the CEC Program through a variety of measures. The Company will use similar successful strategies to what we have seen in the CEC program in Florida which may include channels such as email campaigns, direct mail, bill messages, social media and webinars for industrial, commercial and government customers. There will also be webpages on www.duke-energy.com for customers to gain information as well as enroll in the program. Large Account Managers, Community Relations Managers and other Duke Energy employees will be trained to discuss this program with individual customers.

Q. WILL THE CEC PROGRAM EXPAND ACCESS OF SOLAR POWER TO CUSTOMERS?

A. Yes, in two ways. First, by leveraging the utility's buying power, the CEC Program allows customers to utilize additional solar resources in Kentucky at a lower price than if they put up their own solar systems. Second, the CEC Program allows customers who cannot or do not want to put solar on their premise to participate in a solar energy program.

Q. IN WHAT OTHER WAY DOES THE CEC PROGRAM INCREASE ACCESS TO SOLAR ENERGY FOR CUSTOMERS?

A. Customers who do not have advantageous rooftop space, either due to orientation or shading, are currently not ideal candidates to invest in their own solar generation. The CEC Program is an offering that allows these customers to contribute to increased solar generation.

Q. WHAT WILL BE THE CAPACITY OF THE CEC PROGRAM?

A. The initial solar project is projected to be 49MW and each subscription is 1kW making a total of approximately 49,000 subscriptions available under the program.

Q. TO HOW MUCH CAPACITY WILL EACH CUSTOMER BE ABLE TO SUBSCRIBE?

A. Participating customers may subscribe for up to 100 percent of their previous 12 months of usage in 1 kw block sizes, based on availability. If the customer does not have 12 months of usage Duke Energy Kentucky will estimate it based on partial usage and/or forecasted usage. A calculator will be available to assist customers in converting kwh usage to kw subscription blocks.

Q. HOW WILL THE CEC PROGRAM CAPACITY BE ALLOCATED AMONG DIFFERENT CUSTOMER GROUPS?

A. For the initial project, estimated to be less than 50 MWs, commercial customers, which include new customers, having located or expanded in the Commonwealth in the past five years, will be allocated 37MW. Residential customers will be allocated 10MW and income qualified residential customers will be allocated 2MW. The breakout of these MWs is based on the overall kWh usage by the customer classes. As interest grows, additional subscription interest is expressed, and subsequent assets are supportable, the Company will reappraise the allocation percentages for future participants.

Q. YOU MENTION THAT THE CEC PROGRAM WILL BE AVAILABLE TO INCOME QUALIFIED CUSTOMERS. WILL LOW-INCOME CUSTOMERS SAVE MONEY BY PARTICIPATING IN THE PROGRAM?

A. The income qualified carve-out does not change the overall Net Present Value (NPV) that each customer group contributes or receives; however, for the low income MWs the Company will levelize the overall solar value over the tariff term enabling the income qualified customers to participate and see a net benefit immediately on their monthly bills.

Q. IS THE INCOME QUALIFIED PROGRAM SUBSIDIZED?

A. It is not. The CEC Program was designed to give low-income customers the same benefit/kw subscription on a NPV basis as other customers in the program but adjusted to have relatively more benefits early and less benefits later allowing for bill reductions every year.

Q. HOW WILL THE CEC PROGRAM BE MARKETED TO INCOME QUALIFIED CUSTOMERS?

A. Duke Energy Kentucky will send direct mail, emails, include information in monthly customer bills and on www.duke-energy.com. The Company will also look to partner with local agencies and potentially bundle with other Duke Energy offerings.

Q. HOW WILL A LOW-INCOME CUSTOMER QUALIFY TO BE IN THE CEC PROGRAM?

A. It will depend on the way in which they are applying to the program. Duke Energy Kentucky will host an application at www.duke-energy.com which will allow customers to upload proof of participation in a government subsidy program. Duke Energy Kentucky intends to make the enrollment process simple for income qualified customers.

Q. WHAT IS THE DIFFERENCE BETWEEN THE ELIGIBILITY FOR THE LOW-INCOME ENERGY EFFICIENCY PROGRAMS AND THIS PROGRAM?

A. Duke Energy Kentucky's current low-income energy efficiency programs utilize a 3rd party partner for verification of eligibility, LIHEAP. To qualify, a customer must be within 200 percent Federal Poverty Level. For the CEC Program, customers that qualify for our low-income energy efficiency programs will be eligible, but we are broadening the eligibility to include anyone that can provide documentation of participating in an assistance program.

Q. WILL LOW-INCOME CUSTOMERS EVER SEE THEIR BILL INCREASE AS A RESULT OF PARTICIPATION IN THE CEC PROGRAM?

A. No.

Q. WILL PARTICIPATING CUSTOMERS BE REQUIRED TO ENTER INTO A LONG-TERM CONTRACT?

A. No. Participation in the CEC Program will be voluntary, and customers will be permitted to terminate or change their participation in the CEC Program at any time without penalty. However, if they terminate participation and choose to re-join later, their credit level would start at the year one level. This is to ensure that customers are not able to game the CEC Program and obtain higher level credits without contributing their fair share of subscription fees.

Q. WILL CUSTOMERS BE ABLE TO INCREASE OR DECREASE THEIR SUBSCRIPTION AMOUNTS?

A. Yes. Once per subscription year, a customer may subscribe for additional shares in the program, subject to availability. Customers may withdraw their subscriptions at any point.

Q. WHAT BILL CREDIT RATE WILL CUSTOMERS RECEIVE FOR ADDED SUBSCRIPTIONS?

A. Customers will receive bill credits for additional subscriptions according to the tariffed rates, starting with the year-one credit. For customers that add subscriptions, they will see multiple credit lines on their bill representing the different vintages of their shares. This will ensure that customers cannot add shares in the future without making the appropriate contributions to the program.

Q. WHY START ADDITIONAL SUBSCRIPTIONS AT THE YEAR-ONE CREDIT RATE?

A. This program rule offers benefits to non-participating customers. First, by starting additions at the year-one credit, it will provide more revenue for the program than originally forecasted. For example, if a customer holds a share for five years and then relinquishes the share, that share would be paying the five-year credit rate. If a new customer claims that share in the next year, the credit paid is the year-one credit resulting in program savings to the non-participating customers. While the subscribing customer still sees a payback, the resetting of the credit amounts ends up assigning more of the total program benefits to the non-participating customers.

Second, if additional shares become available for whatever reason, allowing other customers to claim those shares keeps the program fully subscribed, which benefits non-participants as well. Additionally, Duke Energy Kentucky anticipates there will be more interested customers than program capacity and seeks to provide renewable power to as many customers interested in it as possible. The program is designed for participants to fund the renewable facility cost, receive RECs and receive bill savings without long-term commitments. Backfilling subscriptions with new participants allow for participant flexibility and provides even more benefits to the new participant and non-participants.

B. COST EFFECTIVENESS AND PROGRAM PARTICIPATION

Q. HOW WILL DUKE ENERGY KENTUCKY EVALUATE THE COST EFFECTIVENESS OF THE CEC PROGRAM?

A. Duke Energy Kentucky will evaluate the cost effectiveness of the program by comparing the system benefits of the CEC project(s) to their respective costs and program administrative costs. The cost effectiveness of the program will be evaluated over the entire life of the CEC project(s) on a net present value basis. If the value of the system benefits exceeds the value of the anticipated CEC customer bill credits, the program will be deemed cost effective. At the time of the CPCN filing for the CEC project(s), Duke Energy Kentucky will present the Commission its updated cost effectiveness analysis along with the proposed CEC Subscription Fees and customer bill credit schedule.

Q. HOW WILL PARTICIPANT COST AND BENEFITS BE DETERMINED?

A. The Company proposes the formula below which will be refreshed with final numbers derived from items such as final project cost, impacts arising from the recent Inflation Reduction Act, as well as an updated value stream generated from the CEC facility.

Subscription Fee Formula: The NPV of the Subscription Fee assuming 100 percent participation for the entire program life will be equal to the NPV of 105 percent of the CEC Program Cost less 75 percent of the Capital Deferral/Capacity Benefits Associated with the underlying asset(s). The subscription fee will be a fixed $/kW-month value for the duration of the program.

Bill Credit Formula: The NPV calculation of the CEC bill credit will be capped to ensure only a bill credit needed to generate the forecasted participant program payback is provided to the CEC participants with all excess values provided to non-participating customers. The CEC bill credit will be stated on a $/kWh basis. In no event will the NPV of the anticipated CEC bill credit, less the subscription fee, exceed the projected NPV of the total system savings of the underlying asset(s). The CEC Program will rely upon value streams similar to those used in the IRP such as Energy, Capacity, O&M, and Ancillary Services. The current underlying framework utilized to evaluate system benefits and cost effectiveness of demand side resources in the IRP does not recognize an explicit value of carbon. Given the Commission's valuation of demand side management (DSM) resource in particular, the Company is not currently proposing a carbon value in the valuation of community solar or rooftop solar. Notably, the Company highlights the sharing of benefits with non-participants incorporated in the CEC Program as compared to a net metering framework that provides all the value to net metering participants. See Attachment PLH-1 for a visual presentation.

Q. WHAT COST ASSUMPTIONS WERE USED FOR THE POSSIBLE SOLAR PROJECT REPRESENTED IN THE CEC PROGRAM?

A. The CEC program is based on energy provided by a yet to be determined solar project owned by Duke Energy Kentucky. To represent the capital cost of the proposed solar project, Duke Energy Kentucky used the standard cost assumptions for a fixed-tilt, transmission tied project consistent with such costs within its Generic Unit Summary (GUS) which is used to populate resource costs within its planning models. Operations and maintenance costs leveraged the standard cost inputs for the same fixed-tilt asset. Duke Energy Kentucky has land control for parcels that could support such a resource. Consistent with locating the resources on utility property, we have reduced the above mentioned generic operations and maintenance cost by the embedded land lease costs for the purpose of the CEC example. Leverage of such land resources could yield a lower cost to the general body of retail customers and CEC participants.

Q. WHAT ARE THE PRIMARY DRIVERS OF THE BENEFITS TO DUKE ENERGY KENTUCKY CUSTOMERS?

A. We anticipate the value to Duke Energy Kentucky customers is the capacity value associated with the solar assets within PJM as well as savings in fuel and purchased power expense, operating and maintenance costs and reduced emissions costs primarily. Operation of the proposed facilities displaces fossil generation and future energy purchases over the life of the project, some of which would be sourced from fossil fired generation.

Q. WHAT BENEFITS DO THE PROPOSED SOLAR FACILITIES BRING TO DUKE ENERGY KENTUCKY'S SYSTEM AND CUSTOMERS?

A. The proposed Duke Energy Kentucky solar projects will provide customers with the benefits of cost-effective, clean, renewable energy. These new CEC solar projects will reduce the use of fossil fuels, and therefore reduce CO_2, SO_2, and NO_x emissions. These large-scale solar projects will continue to diversify Duke Energy Kentucky's fuel mix with dependable emissions free energy and additional capacity.

Q. DOES DUKE ENERGY KENTUCKY HAVE A NEED FOR THESE SOLAR PROJECTS?

A. Yes. Duke Energy Kentucky has a need for cost-effective clean generation that will diversify its fuel mix and defer the need for future gas-fired generation. This is in addition to the customer desire for the CEC Program. All Duke Energy Kentucky's customers will benefit from the addition of the solar projects proposed in the CEC Program.

Q. ARE YOU ABLE TO PROVIDE AN EXAMPLE OF THE CALCULATION OF SUCH COSTS AND BENEFITS?

A. Yes, an incremental revenue requirement for a CEC project was calculated within Confidential Attachment PLH-2: DEK CEC Asset Revenue Requirement. The annual revenue requirement is utilized in Confidential Attachment PLH-3: DEK – Community Solar Program Support. as part of the overall program revenue requirement of the “Rev Rq_Benefits” tab. Additionally, an estimate of the annual costs to administer the CEC program is also included. The total of these two values represents the CEC program costs. In this example, the CEC Program Costs represent a net present value (NPV) of [redacted]

As discussed previously, CEC Program Benefits include both variable and fixed benefits. The variable benefits include avoided energy purchases, fuel and O&M savings as well as ancillary services benefits. The fixed benefits, consist of capital and capacity deferral values as well as avoided firm gas transmission costs. These fixed benefits are referred to as the Capital Deferral/Capacity Benefits. In Confidential Attachment PLH-3, the Variable and Capital Deferral/Capacity Benefits represent a NPV of [redacted] million and [redacted] million, respectively.

The combined CEC Program Benefits example equal [redacted] million against a total CEC Program Cost of [redacted] million. The difference between these values, [redacted] million, represents the System Savings available for sharing between CEC participants and the general body of retail customers.

Q. WHY CHOOSE THIS PARTICULAR FORMULA FOR THE CEC SUBSCRIPTION FEE?

A. The Company felt it was important to show CEC Program participants would pay slightly more than 100 percent of the CEC Program Costs in exchange for direct participation in the program to insulate the general body of retail customers from such costs. The Company acknowledges these fixed costs also generate fixed capital and capacity benefits. Given the CEC participants are allocated 105 percent of the CEC Program Costs and with the underlying premise the CEC Program shares in the benefits, the Company felt it was appropriate to allocate a larger portion of the fixed benefits to CEC participants.

Q. ARE YOU ABLE TO PROVIDE AN EXAMPLE OF THE RESULTING SUBSCRIPTION FEE, ENERGY CREDIT AND SHARING OF SAVINGS?

A. Yes. As mentioned in my earlier testimony, the CEC Subscription Fee would represent 105 percent of the CEC Program Costs of [redacted] million less [redacted] percent of the Capital Deferral/Capacity Benefits of [redacted] million. This results in a CEC Subscription Fee value is [redacted] million. When the target value is then levelized over the 30-year program life and expressed as a $/kW-month rounded to the nearest $0.01, the NPV is [redacted] million. In the provided example, the CEC Subscription Fee equals [redacted]/kW-month and would be applicable to all participants.

The CEC bill credit for this example is derived to create a nominal payback to low-income participants in the 10th year following initial subscription in the program. The CEC bill credit in this example escalates at an annual rate of [redacted] percent. In order to achieve the desired payback, the NPV of the CEC bill credit will be equal to approximately [redacted] percent of the CEC subscription fee, or a value of [redacted] million. Converting the CEC bill credit to a unit charge yields a Year 1 value of [redacted] cents/kWh. For low-income participants, the CEC bill credit is expressed as a levelized monthly value stated on a $/kW-month basis which is equivalent to the CEC bill credit for low-income participants. In this case the low-income CEC bill credit would be $[redacted]/kW-month.

The portion of the system savings allocated to CEC participants is the CEC bill credit less the CEC subscription fee, or $[redacted] million. In this example, the CEC participants receive 61 percent of the system savings of $[redacted] million.

An example of the calculation for the CEC Program subscription fee and CEC bill credits by year for income qualified and non-income qualified participants is provided on the "CEC Tariff" tab within Confidential Attachment PLH-3. A summary of the net present values and calculation steps are included in the "Notes" tab of the same confidential exhibit. These values will be updated and submitted for Commission approval with the solar facility CPCN filing.

C. IMPACTS TO NON-PARTICIPANTS

Q. WHAT BENEFITS WILL THE CEC PROGRAM PROVIDE TO DUKE ENERGY KENTUCKY'S OVERALL CUSTOMER POPULATION?

A. The solar generation added to the Company's overall system under the CEC Program will displace fossil-fueled generation, thereby lowering emissions and expected fuel expenses for all customers. For this reason, as a cost-effective solar generation system, the CEC Program is expected to put downward pressure on rates over the life of the CEC Program. Additionally, all future value streams that may emerge (such as carbon, distribution, higher marginal energy cost) will be considered in the CEC Program and allocated appropriately to participating and non-participating customers.

Q. HOW DOES THE CEC PROGRAM PROVIDE A VALUE TO NON-PARTICIPATING CUSTOMERS?

A. The CEC Program allocates new generation costs and corresponding benefits between participating customers and the general customer base in a fair and transparent way. The program provides benefits to all customers, while the participants fund all the fixed revenue requirements of the new generation over time. Subscription fee revenues will cover more than 100 percent of the fixed program costs less benefits. And regardless of the ultimate solar values, the participating customers' benefits will not exceed the NPV of the value streams. Additionally, value streams exceeding the proposed participant payback will be 100 percent allocated to non-participating customers. This treatment is similar to DSM measures where the incentive is set at the most reasonable rate to drive cost effective market adoption with all the remaining benefits directed to non-participants. The Company believes this is a fair model to apply to newer clean energy technologies, especially rooftop solar.

Q. WILL THE CEC PROGRAM PROVIDE ENVIRONMENTAL BENEFITS TO PARTICIPATING CUSTOMERS?

A. Yes, Duke Energy Kentucky will retire all RECs on behalf of participants. Customers have told the Company that having a program that helps customers meet their particular renewable energy and sustainability goals was of great importance. The REC treatment in the CEC Program allows participants to claim the renewable energy benefits, helping them meet their individual goals.

Q. WILL THE RECS BE REGISTERED?

A. Yes. RECs will be registered in the North American Renewables Registry (NAR). The NAR system assigns a unique identifier to each REC to enable registration, tracking and retirement. More information on NAR can be found www.apx.com/registries/nar/.

Q. WHY REGISTER THE RECS?

A. It is the registration of the solar generation that creates the REC and the retirement of that REC that allows customers to make the claim that they are using renewable energy as well as provides confirmation that no RECs are double counted. The sustainability goals of large customers are often based on the retirement of RECs. Smaller customers who participate in these programs are not normally familiar with the concept of the REC but have a desire to use renewable power and the REC allows for that.

Q. CAN CUSTOMERS REQUEST TO HAVE RECS TRANSFERRED INTO AN ACCOUNT IN THEIR NAME?

A. Yes, large customers may request RECs associated with their subscription be transferred to an account in their name. The customer would be responsible for setting up a NAR tracking account and any associated costs. They would also be required to provide documentation annually to Duke Energy Kentucky of the RECs being retired.

Q. WHAT HAPPENS IF A CUSTOMER DOES NOT ELECT A SPECIFIC REC TREATMENT?

A. RECs associated with subscriptions will be retired on behalf of all participants.

Q. ARE THERE ANY FEES TO HAVE RECS TRANSFERRED TO A CUSTOMER'S ACCOUNT?

A. NAR charges a fee to transfer RECs. This will be passed through to the participant requesting the transfer. Duke Energy Kentucky will not charge a fee for its services.

Q. HOW WILL DUKE ENERGY KENTUCKY HANDLE RECS FROM UNSUBSCRIBED GENERATION?

A. Duke Energy Kentucky will look to sell any RECs from unsubscribed generation annually at fair market value. We will then pass money received from the REC sales back via the Profit-Sharing Mechanism, as the Company does today with the sales of other solar RECs.

Q. PLEASE DESCRIBE DUKE ENERGY KENTUCKY'S EXPERIENCE WITH DEVELOPING AND BUILDING UNIVERSAL SOLAR FACILITIES AND HOW THIS EXPERIENCE WILL BE LEVERAGED FOR THE DEVELOPMENT OF PROJECTS UNDER THE CEC PROGRAM.

A. Duke Energy considers several factors during project evaluation such as cost-effective interconnection to the grid, environmental impacts, constructability of the site, development status and schedule, overall costs, quality/type of materials (such as panel, inverter, and racking manufacturers), project location, zoning entitlements, and construction schedule. Duke Energy has developed robust relationships with key equipment suppliers (modules, inverters, transformers, SCADA), with Engineering, Procurement, and Construction (EPC) contractors, and with consultants and law firms utilized in the development phase. Duke Energy has developed a robust set of standards and design criteria that are applied to all solar power plants that help streamline request for proposals for major equipment and EPC services and help streamline construction and operations. As such, Duke Energy has a successful track record of developing universal solar facilities on budget and on schedule.

Q. WILL EXISTING DUKE ENERGY KENTUCKY SOLAR FACILITIES BE USED AS CEC PROGRAM RESOURCES?

A. No. Customers will continue to receive the benefits of the existing distribution-tied solar resources as they are today. The CEC program is intended to facilitate the construction of new solar facilities that will be dispatched into the markets for customers. This will allow the program to grow as interest supports it going forward.

Q. IS DUKE ENERGY KENTUCKY PROPOSING TO RECOVER ANY OF THE COST OF THE CEC PROGRAM IN THIS CASE?

A. No. The Company is requesting approval of a placeholder tariff in this proceeding. If the Commission approves this concept in this proceeding, the Company will aggressively obtain initial subscriptions and file a CPCN for approval of the actual CEC project. Cost recovery would be requested in a future proceeding. Company witness Sarah E. Lawler discusses this further in her testimony.

D. CEC PROGRAM IMPLEMENTATION TIMELINE

Q. WHEN DOES THE COMPANY ANTICIPATE THE CEC PROGRAM TO BEGIN OPERATING?

A. The commercial operation of the CEC Program is projected to begin by 2025 with completion of its first asset. As previously described, Duke Energy Kentucky will seek Commission approval through Kentucky's CPCN process for construction of any CEC Program resources. If customer demand exceeds the available capacity of any project, customers will be placed on a waitlist to replace customers who leave the program or until new resources can be sited, approved, and constructed.

Q. WHERE WILL THE PROJECTS MAKING UP THE CEC PROGRAM BE LOCATED?

A. The project(s) will be within Duke Energy Kentucky's PJM Delivery Zone, known as the DEOK Zone, bringing geographic diversity to the program's production for the Duke Energy Kentucky system.

Q. HOW WILL CUSTOMER SUBSCRIPTIONS BE IMPLEMENTED IN RELATION TO SITING, CPCN APPROVAL, AND CONSTRUCTION OF THE SOLAR FACILITIES?

A. Customer subscriptions will start once the solar facility achieves commercial operation.

Q. HOW WILL DUKE ENERGY KENTUCKY ENROLL RESIDENTIAL AND SMALL BUSINESS CUSTOMERS IN THE CEC PROGRAM?

A. Duke Energy Kentucky will utilize a web-based enrollment system for residential and small business customers that will be a first come, first serve process, which will allow customers to view and select the subscription level that suits their needs. As always, Duke Energy Kentucky customer representatives will be available to assist customers seeking to enroll in the CEC Program.

Q. WHY IS THE RESIDENTIAL AND SMALL BUSINESS ENROLLMENT PROCESS DIFFERENT FROM LARGE CUSTOMER?

A. Based on the expected demand from large customers, we will have a window for them to submit interest in the program and they requested subscription amount. This would allow an opportunity for all interested to participate though if demand exceeded capacity in the program, the subscription amounts for each individual customer will be brought down proportionally to meet the capacity available in the program.

Q. WHAT IF THERE IS MORE DEMAND THAN CAPACITY AVAILABLE?

A. Duke Energy Kentucky anticipates that there will not be enough capacity for all interested customers. Once capacity has been subscribed, Duke Energy Kentucky will maintain a waiting list of interested customers to ensure that as customers leave the program, new customers can participate, and it stays fully subscribed. To fairly distribute capacity among large customers, upon approval of the CEC Program, Duke Energy Kentucky will open an enrollment window 6 months prior to the expected facility's commercial achievement date.

Q. WILL CEC PROGRAM PARTICIPANTS HAVE ACCESS TO INFORMATION ABOUT THE SOLAR PLANTS?

A. Yes, participants will have access to program information tailored to their subscription level when they log into their account at www.duke-energy.com. The dashboard will show fees paid, credits earned and solar generation

III. CONCLUSION

Q. WERE ATTACHMENTS PLH-1 THROUGH PLH-3 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Paul Halstead, Director Jurisdictional Rate Administration, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Paul Halstead

Paul Halstead Affiant

Subscribed and sworn to before me by Paul Halstead on this 29th day of November, 2022.

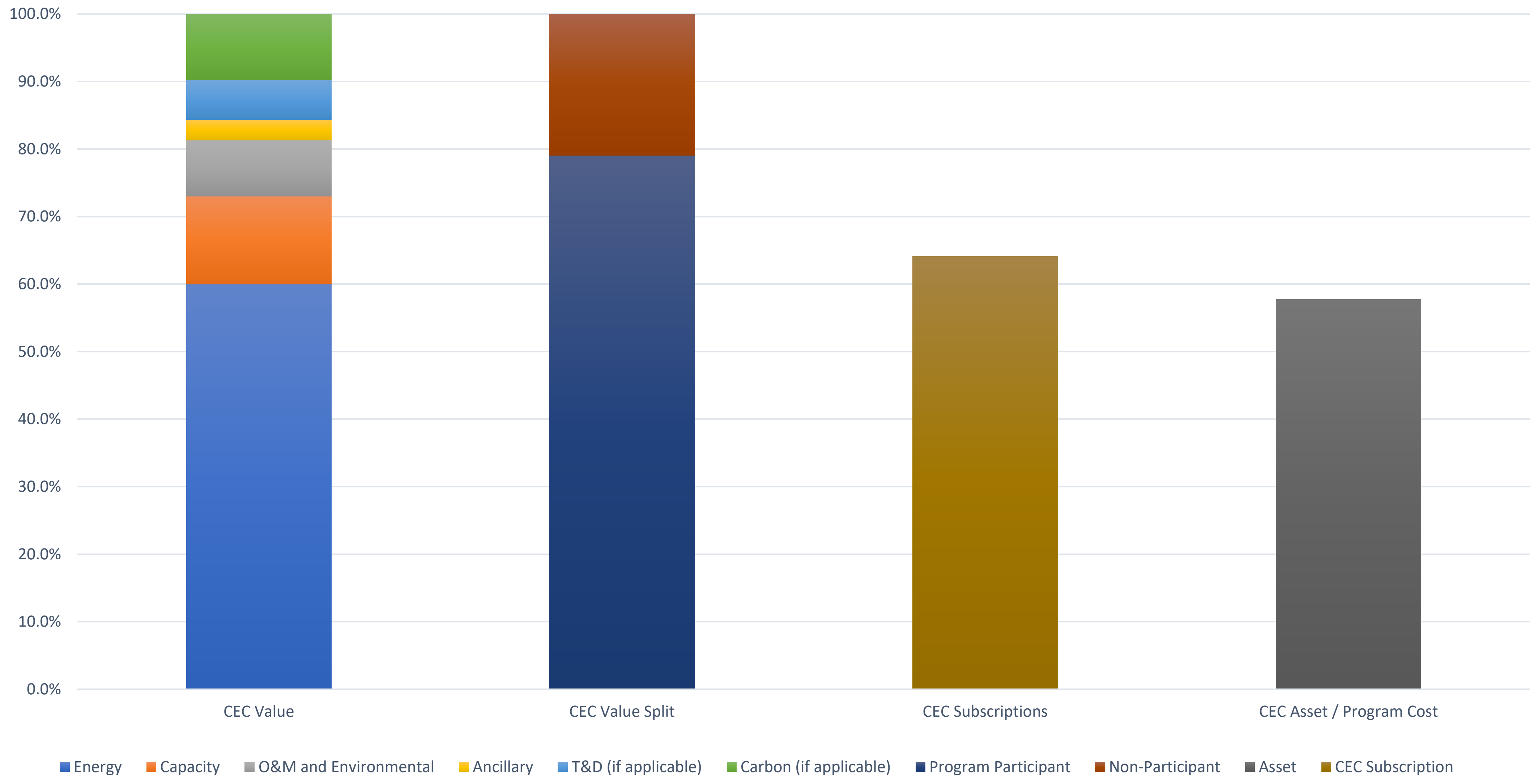
Ruby H Chambers

NOTARY PUBLIC

My Commission Expires: May 30, 2027

RUBY H. CHAMBERS
NOTARY PUBLIC
STANLY COUNTY, N.C.
My Commission Expires May 30, 2027

For Illustrative Purposes Only



CONFIDENTIAL PROPRIETARY TRADE SECRET

PAUL L. HALSTEAD TESTIMONY ATTACHMENT PLH-2

FILED UNDER SEAL

CONFIDENTIAL PROPRIETARY TRADE SECRET

PAUL L. HALSTEAD TESTIMONY
ATTACHMENT PLH-3

FILED UNDER SEAL

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

RETHA I. HUNSICKER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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PAGE

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Retha I. Hunsicker and my business address is 400 South Tryon Street, Charlotte, North Carolina, 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS), as Vice President, Customer Experience Design and Solutions. DEBS provide various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor of Science degree in Business Administration from Indiana Wesleyan University. Since 1981, I have been employed by, and worked for, companies under what is now Duke Energy. I began my career with Public Service Indiana, the predecessor to Duke Energy Indiana, LLC, (Duke Energy Indiana) as an accounting assistant. Since then, I have held positions with increasing levels of responsibility. More recently, the roles I've held include Director, Business Standards and Integration, and General Manager, Smart Energy Systems & Processes. In 2012, I took the position of Regional Director, Customer Services, leading our Midwest contact centers, before promoting to Vice President, Customer Contact Operations in 2013. Beginning in 2015, I led the customer information system (CIS) consolidation project known as Customer Connect, and I assumed my current role as Vice President Customer Experience Design and Solutions in May 2022.

My previous experience has provided me great insight into customer needs, Duke Energy processes and technology solutions. With this experience, I oversaw the planning, execution and deployment of the Customer Connect platform, which enables the functional capabilities needed to meet our strategic purpose of powering the lives of our customers by transforming how we serve them.

Q. PLEASE DESCRIBE YOUR DUTIES WITH CUSTOMER CONNECT AND AS VICE PRESIDENT CUSTOMER EXPERIENCE DESIGN AND SOLUTIONS

A. I have executive management oversight for Customer Connect, including its planning, execution and deployment. As Vice President Customer Experience Design and Solutions I lead the design and execution of end-to-end strategies for measurement, valuation, and improvement of the customer experience. I oversee customer marketing, engagement, and analytics, as well as the development and optimization of technology solutions that transform how customers experience and interact with Duke Energy.

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

A. Yes. I have testified before the Kentucky Public Service Commission, most recently in Case No. 2021-00190.

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

A. The purpose of my testimony is to discuss the Company's legacy CIS, why it was necessary to convert that CIS into a modern customer service platform, and the implementation of the Customer Connect platform with regard to Duke Energy Kentucky.

II. <u>DISCUSSION</u>

Q. PLEASE EXPLAIN THE PURPOSE OF A CIS.

A. The CIS manages the billing, accounts receivable, and rates for the Company and is the central repository for all customer information. It links the consumption and metering processes to payments, collections, and other downstream processes. The CIS manages customer profiles and integration of data to provide a holistic view of the customer and should enable expected customer capabilities.

Q. PLEASE PROVIDE AN OVERVIEW OF THE NEW CUSTOMER CONNECT SYSTEM AS COMPARED TO THE COMPANY'S LEGACY SYSTEM.

A. Customer Connect is a customer engagement platform, including a CIS, which is a system that manages the billing, accounts receivable, and rates for the Company as a central repository for all customer information. A CIS links the consumption and metering process to payments, collections, and other downstream processes including additional work order requests such as service connections and disconnections, outages, and trouble requests. A CIS also manages customer profiles and integration of data to provide a holistic view of the customer and should enable expected customer capabilities.

The prior CIS (legacy CIS) for Duke Energy Kentucky was developed more than thirty years ago, beginning in 1987, and was put into service in 1993. Although state-of-the-art nearly thirty years ago, the legacy CIS was not designed to efficiently support new capabilities, including personalized experiences for our customers, advanced pricing structures and billing options, and tools for customers to better manage their energy consumption. Further, the design limitations of the prior CIS required complex billing functions to be performed manually.

Q. WHAT BENEFITS DOES THE CUSTOMER CONNECT SYSTEM PROVIDE TO CUSTOMERS?

A. Customer Connect was implemented for Duke Energy Kentucky in April 2022, providing the following key customer benefits and associated customer experience improvements:

- Modern, Configurable Billing Engine - improving the Company's responsiveness to regulatory or market changes and ability to implement modern rate structures (*e.g.*, net metering, time-of-use, etc.);
- Customer-Centric Data Model - Enables a "one customer" view, enabling the Company to know the customer better and provide a more streamlined, personalized experience;
- Holistic Customer Profile - The prior CIS only stored basic customer information - name, phone, address, premise and historical usage, billing, and payment information - preventing us from knowing our customers

beyond these basic attributes. Customer Connect stores all of that same information and more, gathering all of the relevant touchpoints that customers are having with Duke Energy Kentucky in real time - web visits, phone calls, power outages, outbound communications, product and service participation, etc. - to build out a holistic view of customers that can be leveraged to better serve them and personalize their experience;

- Integrated Analytics - This customer profile data is then leveraged by the integrated analytics capabilities of the new platform to personalize experiences and better serve customers through every channel. For example, the new platform predicts the intent of customers when they call Duke Energy Kentucky, thereby improving their experience. This same capability can be leveraged to prioritize what information is conveyed to the customer and in the medium preferred by the customer, whether it is via web, email, or other channels, to ensure it is timely, relevant and valuable to them. These are just two examples of the multiple opportunities to leverage real-time analytics to improve our customers' everyday experience with Duke Energy Kentucky.
- Multi-Company - With the prior CIS, customers existed as separate entities across jurisdictions. When a customer moved from one jurisdiction to another, all information about that customer was lost - communications preferences, product and service participation, etc. With Customer Connect, these types of account attributes remain at the customer level throughout

their experience with Duke Energy as they move between locations and jurisdictions.

Q. PLEASE DISCUSS THE IMPLEMENTATION STAGES AND TIMELINE FOR THE CUSTOMER CONNECT PROJECT.

A. The Customer Connect project was comprised of three main implementation stages: 1) Implementation, 2) Stabilization, and 3) Optimization. The primary focus for the Customer Connect program has been to successfully implement the new system for all of Duke Energy's regulated electric and natural gas utilities (excluding Piedmont Natural Gas), and to stabilize the platform following those deployments. The Customer Connect program initially deployed the final stages of the platform in April 2021 for Duke Energy Carolinas, followed by deployment in November 2021 for Duke Energy Progress and Duke Energy Florida. The final deployment for Duke Energy Indiana, Duke Energy Kentucky, and Duke Energy Ohio was complete in April 2022. As mentioned earlier, each implementation is followed by a period during which heightened support (known as Hypercare) is provided to end users and customers. The goal of Hypercare is to navigate and limit negative impacts to customers. Following stabilization for all deployments the Company will leverage and optimize the new platform and processes to enhance the customer experience while also improving work efficiencies and maintaining system performance.

Q. PLEASE DISCUSS THE IMPLEMENTATION EXPERIENCE FOR THE COMPANY AND ITS CUSTOMERS.

A. The Customer Connect Program was fully implemented for Duke Energy Kentucky on April 6, 2022. With this implementation, the Company successfully transitioned all customer account data from its legacy billing system to the new Systems, Applications and Products in Data Processing (SAP) billing system, including more than 200,00 accounts, and balancing approximately $46 million in accounts receivable. Meter reads, billing, and payments ("batch billing") were processed without manual intervention on day one of the transition and the systems have been performing well, maintaining over 99 percent availability. The Company intentionally reviewed bills for complex accounts to ensure they were established and billing correctly before sending the bills to customers. As shown below, the Company's deployment and stabilization of Customer Connect performed far better in the first 90 days than the industry benchmark metrics.

Figure 1 – Post-Implementation Billing Metrics

Metric (Post Go-Live)	**Duke Energy (DEK) End of Month 1**	**Duke Energy (DEK) End of Month 3**	**Industry Benchmark (First 6 months avg.)**
Delayed Bills	<1%	<1%	1-3%
Open Exceptions Impacting Billing	~80	~230	~500
Batch Billing meeting all thresholds without intervention *	Day 1	Day 1	By Day 60
*Batch billing encompasses the creation/posting of meter reads and usage information, payment, service orders, billing, invoicing, associated accounting, and general ledger.			

As shown above, regarding batch billing being processed without manual intervention, the industry benchmark is to reach this metric by day 60, and the Company reached this benchmark on day one. Furthermore, the Company had less than one percent of bills delayed following its deployment, while the industry standard is a 1-3 percent average within the first six months of a customer information system deployment. Likewise with respect to open exceptions, which are accounts that require review prior to the invoice being sent to the customer, Duke Energy Kentucky had approximately 230 at the end of its first 90 days after deployment, exceeding the benchmark average of 500 for the first six months post-deployment.

Additionally, with the deployment of Customer Connect, the Company made improvements in processing customer requests via its website and IVR and has seen a steady increase in customers taking advantage of fully automated processes such as move requests and billing and payment program enrollments.

The Company has also begun tracking customer behaviors post go-live and has noted customer adoption of new or enhanced self-service options. For example, since the deployment of Customer Connect nearly 24 percent of Midwest (Ohio, Kentucky, and Indiana) start service requests are being completed through self-service options (i.e., website and IVR).

Finally, ahead of deployment, the Company increased both its call center and back-office staffing to minimize impacts to customers as employees were learning a new system. The Customer Connect program team implemented robust communications and contingency plans to respond to issues and have responded quickly with numerous external communications including outbound calls and email communications, as well as messaging on the external website and automated phone system to address customer confusion post-deployment.

Q. DID THE COMPANY APPLY ANY LEARNINGS FROM ITS CUSTOMER CONNECT DEPLOYMENT AT ANY OF ITS AFFILIATES WHEN IT IMPLEMENTED CUSTOMER CONNECT FOR DUKE ENERGY KENTUCKY?

A. Yes. The Company demonstrated learnings from previous deployments as shown in the outcomes of the first three months post go-live for Duke Energy Kentucky. The key areas of focus for the deployment, which proved to be beneficial, included: 1) enhanced pre-deployment messaging to customers, including all outbound communications, IVR and website messages to ensure customers were aware of upcoming system changes, down times, and suspension of disconnections for non-payment; 2) improved the overall Company processes during the cutover period (where there were planned limited system capabilities) by leveraging technical solutions and increasing training for Customer Care Operations, which included calls handled during the cutover period, the manual forms process, and the ability to process payments during the cutover; 3) corrected known data and conversion issues for complex billing; and 4) improved training for complex scenarios by providing hands-on training in new system ahead of go-live for Duke Energy Kentucky and provided supplemental training material.

Q. PLEASE DISCUSS HYPERCARE AND THE STABILIZATION PERIOD EXPERIENCE FOR THE COMPANY AND ITS CUSTOMERS.

A. The platform stabilization period, called Hypercare, began immediately upon deployment and included activities such as heightened support for employees working in the new system (Customer Care, Billing, Accounts Receivable, Delivery Operations, etc.), issue tracking and resolution, and customer communications. As discussed above, the goal of stabilization is to navigate and limit negative impacts to customers immediately following the implementation of the new system. During this time, the Customer Connect team closely monitors system and operational performance along with issue resolution and communicates impacts, where applicable, to customers and Suppliers. Hypercare activities were closed out as operations returned to normal. Following the Duke Energy Kentucky deployment, this process was generally complete in August 2022. Platform stabilization follows Hypercare and lasts until all deployments are complete.

Q. IS DUKE ENERGY KENTUCKY PROPOSING TO RECOVER ANY OF THE COST OF THE CIS REPLACEMENT IN THIS CASE?

A. Yes. The gross plant in this proceeding includes approximately $9 million related to the CIS system (including hardware) which was placed in-service as of April 6, 2022, as supported by Company witness Huyen C. Dang.

III. <u>CONCLUSION</u>

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

A. Yes.

VERIFICATION

STATE OF INDIANA	**)**	
	)	**SS:**
COUNTY OF TIPPECANOE	**)**	

The undersigned, Retha Hunsicker, VP Customer Experience Design and Solutions, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Retha Hunsicker Affiant

Subscribed and sworn to before me by Retha Hunsicker on this 22 day of Nov, 2022.

AMY MCCLARAN LONG
Notary Public, State of Indiana
Tippecanoe County
Commission Number NP0726351
My Commission Expires
April 20, 2028
NOTARY PUBLIC SEAL INDIANA

NOTARY PUBLIC

April 20, 2028

My Commission Expires

VERIFICATION

STATE OF INDIANA)
) **SS:**
COUNTY OF TIPPECANOE)

The undersigned, Retha Hunsicker, VP Customer Experience Design and Solutions, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Retha Hunsicker Affiant

Subscribed and sworn to before me by Retha Hunsicker on this 22 day of NOV, 2022.

NOTARY PUBLIC

AMY MCCLARAN LONG
Notary Public, State of Indiana
Tippecanoe County
Commission Number NP0726351
My Commission Expires
April 20, 2028

NOTARY PUBLIC SEAL INDIANA

April 20, 2028
My Commission Expires

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

JEFFREY T. KOPP

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

December 1, 2022

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey (Jeff) T. Kopp, and my business address is 9400 Ward Parkway, Kansas City, Missouri 64114.

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

A. I am employed by 1898 & Company (1898 & Co), which is part of Burns and McDonnel Engineering Company (BMcD) as Senior Managing Director the Utility Consulting Department. BMcD has been in business since 1898, serving multiple industries, including the electric power industry. In 2022, BMcD was rated No. 8 overall of the Top 500 Design Firms by the Engineering News Record (ENR). BMcD was rated as the No. 1 engineering design firm in the United States serving the electric power industry by ENR in 2022.

1898 & Co and BMcD has vast experience in both preparation of dismantlement studies and executing construction projects, including hundreds of construction projects totaling more than $1 billion dollars of construction last year alone. In order to execute over $1 billion dollars of construction projects on an annual basis, BMcD has to win this work through competitive bidding processes, which requires us to be able to accurately prepare cost estimates.

Our long history, large market presence, and top industry rankings demonstrate our ability to effectively and accurately estimate costs. In addition, we have worked with demolition contractors over the years to refine our estimating process for dismantlement studies to align our costs with theirs.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS A MANAGING DIRECTOR IN THE BUSINESS CONSULTING DEPARTMENT OF 1898 & CO.

A. I am a professional engineer with 21 years of experience consulting to electric utilities. I have been involved in numerous decommissioning studies and served as project manager on the majority of them. I have helped prepare decommissioning studies on all types of power plants utilizing various technologies and fuels.

As Senior Managing Director of 1898 & Co, I oversee a practice that includes a team of nearly 200 project managers, consultants, and analysts who provide consulting services to clients primarily in the electric power generation and electric power transmission industries, but also to other industrial and commercial clients. The services provided by this group includes decommissioning cost studies, independent engineering assessments of existing power generation assets, economic evaluations of capital expenditures, new power generation development and evaluation, electric and water rate analysis, electric transmission planning, distribution planning, generation resource planning, renewable power development, and other related engineering and economic assessments.

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

A. I have a Bachelor's Degree in Civil Engineering from the University of Missouri – Rolla (now the Missouri University of Science and Technology) and a Masters of Business Administration from the University of Kansas. In my role as a group manager, project manager, and project engineer, I have worked on and have overseen consulting activities for coal, natural gas, wind, solar, hydroelectric, and biomass power generation facilities.

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

A. Yes. I previously provided testimony in support of Duke Energy Kentucky, Inc.'s (Duke Energy Kentucky or the Company) electric rate case in 2017, Case No. 2017-00321.

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

A. The purpose of my testimony is to describe and support Duke Energy Kentucky, Decommissioning Cost Estimate Study (Decommissioning Study) for its East Bend Generating Station (East Bend) Woodsdale Combustion Turbines (Woodsdale), and the Miami Fort Unit 6 Generating Station (MF6), Crittenden Solar Project (Crittenden), and Walton Solar Project (Walton) (collectively the Plants).

II. DUKE ENERGY KENTUCKY'S DECOMMISSIONING STUDY

Q. PLEASE DESCRIBE THE DECOMMISSIONING STUDY PREPARED FOR THE COMPANY.

A. The Company retained 1898 & Co to provide it with a recommendation regarding the total cost, in 2022 dollars, of decommissioning each Company-owned generation unit at the end of its useful life as well as the total cost of decommissioning the common facilities at these generating plants. The total decommissioning cost as determined by 1898 & Co and reflected in the Decommissioning Study was net of salvage value for scrap materials at each plant.

Q. WHAT PLANTS DID 1898 & CO EVALUATE IN THE 2022 DECOMMISSIONING COST STUDY?

A. For purposes of the Decommissioning Study, we evaluated five of the Company's electric generating plants, which includes East Bend, Woodsdale, MF6, Crittenden, and Walton.

Q. WHAT WAS THE EXTENT OF YOUR PERSONAL INVOLVEMENT IN THE PREPARATION OF THE DECOMMISSIONING STUDY?

A. I served as the 1898 & Co project director on the Decommissioning Study. I worked directly with the project manager in the preparation of the decommissioning cost estimates in the Decommissioning Study. I was responsible for the overall project approach and direction as well as the final deliverables.

Q. WHAT APPROACH WAS USED TO DEVELOP THE DECOMMISSIONING ESTIMATES IN THE DECOMMISSIONING STUDY?

A. The estimate of direct dismantlement costs was prepared with the intent of most accurately representing what 1898 & Co would anticipate contractors bidding to dismantle the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known dismantlement tasks under ideal conditions. In addition to these known tasks under ideal conditions, indirect costs are added to cover cost incurred by the Company in executing the projects, and contingency is added to account for unknown, but reasonably expected to be incurred costs.

As outlined in the Decommissioning Study, we prepared these cost estimates by estimating quantities for equipment based on a visual inspection and interaction with the facilities' staff, review of engineering drawings, 1898 & Co's in house database of plant equipment quantities, and 1898 & Co's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, scrap materials, and unit pricing were then developed for each task. These rates were applied to the quantities for the plants to determine the total cost of decommissioning for each site.

Q. WHAT LEVEL OF DECOMMISSIONING AND DEMOLITION WAS ASSUMED TO BE PERFORMED AT EACH OF THE SITES?

A. The basis of the estimates was that all sites will be restored to a condition suitable for industrial use.

Q. WHAT DOES RESTORING THE SITE FOR INDUSTRIAL USE REQUIRE?

A. The sites will have all above grade buildings and equipment removed, foundations removed to two feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. The sites can remain in this condition in perpetuity, until the site is specifically redeveloped for industrial use.

Q. DID YOU VISIT EACH OF THE SITES FOR WHICH THE SITE-SPECIFIC COST ESTIMATES WERE DEVELOPED?

A. Yes. I visited all sites for which site-specific decommissioning cost estimates were prepared, along with other individuals from 1898 & Co, and representatives from the Company.

III. DESCRIPTION OF DECOMMISSIONING COSTS

Q. GENERALLY EXPLAIN THE TYPE OF COSTS REFLECTED IN THE DECOMMISSIONING STUDY.

A. The estimates reflected in the Decommissioning Study are inclusive of direct costs associated with decommissioning and demolishing the plant equipment and facilities and restoring the sites to an industrial condition. The direct costs include environmental remediation costs for asbestos removal and other hazardous material handling and disposal, as well as costs for removing and disposing of contaminated soil. The Decommissioning Study also includes estimates of indirect costs to be incurred by the Company during decommissioning and contingency costs.

Q. HOW WERE THE DIRECT COSTS DEVELOPED FOR PURPOSES OF THE DECOMMISSIONING STUDY?

A. As part of the Decommissioning Study, site-specific cost estimates were developed using a "bottom-up" cost estimating approach, where cost estimates are developed from scratch through the development of site-specific quantity estimates and the application of unit pricing to the quantity estimates.

1898 & Co estimated quantities based on a visual inspection of the facilities, review of engineering drawings, 1898 & Co's in-house database of plant quantities, and 1898 & Co's professional judgment. This resulted in an estimate of quantities for the tasks required to be performed for each decommissioning effort. Current market pricing for labor rates, equipment, and unit pricing were then developed for each task. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning for each site. Additionally, unit pricing for scrap values was applied to the scrap quantities to determine anticipated salvage values, which were subtracted from the direct costs for demolition in order to arrive at a total net project cost in 2016 dollars.

Q. HOW WERE SCRAP VALUES CALCULATED?

A. Scrap metal prices used in the development of the scrap credit were based on a review of recent pricing trends for various types of materials published by American Metal Market, which is an industry standard publication and information subscription service (see http://www.amm.com) that reports the prices paid for scrap metals in transactions worldwide.

American Metal Market is the leading independent supplier of market intelligence and pricing to the North American metals industries and publisher of the widely-used reference prices for scrap. American Metal Market also has extensive experience in reporting scrap prices in a wide range of grades and locations. American Metal Market has been reporting on the U.S. scrap market for more than 100 years, providing benchmark prices to users in the scrap metal industry.

Q. WHAT IS INCLUDED IN THE PROJECT INDIRECT COSTS INCLUDED IN THE 2022 DECOMMISSIONING COST STUDY?

A. This category includes costs expected to be incurred by the Company during the decommissioning process, which would be in addition to the direct costs paid to a demolition contractor. This includes the costs for staff of the Company providing oversight during demolition activities, inspections, and testing to confirm that remediation has been completed, as well as Company overheads, general and administrative costs.

Q. HOW WERE THE INDIRECT COSTS DETERMINED?

A. Indirect costs were determined as a percentage of the direct costs, as is a typical approach when preparing these types of cost estimates. The percentage of direct costs that was applied to determine the indirect costs was developed by 1898 & Co based on experience with recent decommissioning estimates.

Q. WHAT IS INCLUDED IN THE CONTINGENCY COSTS?

A. A contingency cost includes unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and demolition activities. For decommissioning projects, there is some uncertainty associated with work conditions, the scope of work and how the work will be performed. There also is some uncertainty associated with estimating the quantities for dismantlement of facilities. These uncertainties result from the age and limits on drawings available, as well as the absence of testing results for environmental contamination prior to preparation of these types of studies. Contingency costs account for these unspecified but expected costs and are in addition to the direct costs associated with the base decommissioning costs for known scope items.

Q. ARE CONTINGENCY COSTS STANDARD INDUSTRY PRACTICE?

A. Yes. The application of contingency is not only appropriate, but also standard industry practice. Even on a project where firm pricing has been agreed upon with a successful bidder, it is typical that a client carry some level of contingency to cover potential change orders. It is even more important to carry contingency on planning level cost estimates such as those presented in the Decommissioning Study.

IV. CONCLUSION

Q. DID YOU PROVIDE ANY INFORMATION TO OTHER WITNESSES FOR THEIR USE IN THIS PROCEEDING?

A. No.

Q. WAS THE DECOMMISSIONING STUDY ATTACHED TO YOUR TESTIMONY AS ATTACHMENT JTK-1 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

Q. ARE THE ESTIMATED COSTS REFLECTED IN THE DECOMMISSIONING STUDY REASONABLY REFLECTIVE OF THE ACTUAL COSTS NECESSARY TO DISMANTLE THE COMPANY PLANTS?

A. Yes, they are.

Q. ARE THESE ESTIMATED COSTS APPROPRIATE FOR USE IN THE DEVELOPMENT OF DEPRECIATION RATES FOR THE COMPANY'S ELECTRIC GENERATING PLANTS?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF Missouri)
) SS:
COUNTY OF Jackson)

The undersigned, Jeffrey Kopp, Managing Director the Business Consulting Department, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Jeffrey Kopp

Jeffrey Kopp Affiant

Subscribed and sworn to before me by Jeffrey Kopp on this 30 day of Nov, 2022.

Linda R. Olvera

NOTARY PUBLIC

My Commission Expires: 10/11/2024

Linda R. Olvera
Notary Public-Notary Seal
STATE OF MISSOURI
Commissioned for Jackson County
My Commission Expires: 10/11/2024
ID. #12403570

Decommissioning Cost Estimate Study

Duke Energy Kentucky

Decommissioning Cost Estimate
Project No. 146598

7/14/2022

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LIST OF ABBREVIATIONS

Abbreviation	Term/Phrase/Name
1898 & Co.	1898 & Co., part of Burns & McDonnell
BOP	Balance of Plant Facilities
C&D	Construction and Demolition
Client	Duke Energy Kentucky
CT	Combustion Turbine
DEK	Duke Energy Kentucky
ESP	Electrostatic Precipitator
FGD	Flue Gas Desulfurization
HDPE	High-Density Polyethylene
HRSG	Heat Recovery Steam Generator
PCB	Polychlorinated Biphenyls
Plants	Power Generation Assets
SCR	Selective Catalytic Reduction
ST	Steam Turbine
Study	Decommissioning Cost Study

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1.0 EXECUTIVE SUMMARY

1.1 Introduction

Duke Energy Kentucky ("DEK") retained 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (hereinafter called "1898 & Co."), to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") located in Kentucky and Ohio. The assets include natural gas-fired, coal-fired, and solar generating facilities. The purpose of the Study was to review the facilities and to make a recommendation to DEK regarding the total cost to decommission the facilities at the end of their useful lives. The decommissioning costs were developed by 1898 & Co. using information provided by DEK and in-house data available to 1898 & Co.

1.2 Results

1898 & Co. has prepared cost estimates in 2022 dollars for the decommissioning of the Plants. These cost estimates are summarized in the following Table. When DEK determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a scrap contractor to offset a portion of the decommissioning costs. DEK will incur costs in the demolition and restoration of the sites less the scrap value of equipment and bulk recycled metals. Additionally, DEK's on-site inventory was taken into consideration for the demolition costs. For the combustion turbine ("CT") facility, a salvage value of 25 percent was assumed. For the other Plants, 10 percent of the inventory was assumed to be salvageable. The CT facility was assumed to have a higher inventory salvage value because spare parts for CT are more marketable and can be more easily resold to other owners/operators at a higher premium than just the scrap price of the material.

Table 1-1: Decommissioning Cost Summary (2022$)

Plant	Gross Decom Cost	Inventory Cost	Salvage Credits	Inventory Credits	Net Project Cost
Crittenden Solar	$ 630,700	-	$ (218,400)	-	$ 412,300
East Bend	$ 47,573,000	$ 9,084,000	$ (17,034,000)	$ (908,000)	$ 38,715,000
Miami Fort	$ 8,522,000	-	$ (3,635,000)	-	$ 4,887,000
Walton Solar	$ 880,500	-	$ (294,300)	-	$ 586,200
Woodsdale	$ 14,452,000	$ 5,967,000	$ (7,600,000)	$ (1,492,000)	$ 11,327,000

The total project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development as an industrial facility. Included are the costs to dismantle all power generating equipment and balance of plant ("BOP") facilities and, where applicable, to perform environmental site restoration activities.

2.0 INTRODUCTION

2.1 Background

1898 & Co., a division of Burns & McDonnell Engineering Company, Inc. (hereinafter called "1898 & Co."), was retained by Duke Energy Kentucky ("DEK") to conduct a Study to estimate the decommissioning costs. The assets include natural gas-fired, coal-fired, and solar generating facilities. Individuals from 1898 & Co. visited the Plants evaluated within the Study in May of 2022. The purpose of the Study was to review the facilities and to make a recommendation to DEK regarding the total cost to decommission and dismantle the facilities at the end of their useful lives. 1898 & Co. has prepared over three hundred decommissioning studies on various types of fossil fuel and renewable power plants. In addition to preparing decommissioning cost estimates, 1898 & Co. has supported demolition projects as the owner's engineer. In this capacity, 1898 & Co. has evaluated demolition bids and overseen demolition activities. This has provided 1898 & Co. with insight into a broad range of competitive demolition bids, which also assists in confirming the validity of the decommissioning and dismantling estimates developed by 1898 & Co.

2.2 Methodology

The site decommissioning costs were developed using information provided by DEK and in-house data 1898 & Co. has collected from previous project experience. 1898 & Co. estimated quantities for equipment based on a visual inspection of the facilities, reviews of engineering drawings, an in-house database of plant equipment quantities, and professional judgment. For each Plant, quantities were estimated for each required task. Current market pricing for labor rates and equipment was then developed for each task. The unit pricing was developed for each site based on the labor rates, equipment costs, and disposal costs specific to the area in which the work is to be performed. These rates were applied to the quantities for the Plants to determine the total cost of decommissioning and dismantling.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to decommission and dismantle all the assets owned by DEK at the sites, including power generating equipment and Balance of Plant facilities.

2.3 Site Visits

Representatives from 1898 & Co. and DEK visited the sites in May of 2022. A representative portion of the sites was visited. The site visits consisted of a tour of each facility along with DEK representative, Tim Randall, as well as plant personnel at each of the sites.

The following 1898 & Co. representatives comprised the site visit team:

- Mr. Stephen Henson, Project Manager
- Ms. Abigail Yi, Project Analyst

The following table outlines the dates in which the site visits were conducted.

Table 2-1: Site Visit Dates

Plant	Site Visit Date
Crittenden	May 19, 2022
East Bend	May 19, 2022
Walton	May 19, 2022
Miami Fort	May 20, 2022
Woodsdale	May 20, 2022

3.0 PLANT DESCRIPTIONS

The following sections provide descriptions of the Plants included in this Study.

3.1 Simple Cycle / Combustion Turbines

3.1.1 Woodsdale

Woodsdale plant is located in Trenton, Ohio. The facility consists of six identical natural gas-fired CT operating in simple cycle mode. Operation began in 1992 with Unit 2 through Unit 6, followed by the operation of Unit 1 in 1993. The plant has a total capacity of 564.0 MW, with each unit's nameplate capacity equating to 95.3 MW. The plant has an unlined retention pond. In 2018, the facility removed all propane and installed fuel oil tanks.

3.2 Coal Generation

3.2.1 East Bend

East Bend is located in Union, Kentucky, adjunct to the Ohio River. Originally, it was planned for two or more units to be built, but after the construction and beginning operation of Unit 2 in 1981, no additional units were built to completion. Unit 2 is a coal-fired boiler with a nameplate capacity of 772.0 MW. A steam turbine ("ST") and the concrete for a control center building were built for Unit 1. These assets were left on site and have not been removed. Unit 2 includes a selective catalytic reduction ("SCR") system, an electrostatic precipitator ("ESP"), and flue-gas desulfurization ("FDG") scrubber system. Coal handling facilities include the coal pile is located on the northeast side of the facility, conveying equipment and barge unloading equipment. The facility has concrete cooling towers. Two High-Density Polyethylene ("HDPE") lined retention basins and one holding basin have been constructed since the last study.

3.2.2 Miami Fort

Miami Fort plant consists of four units located in North Bend, Ohio, adjacent to the Ohio River. Commercial operation began in 1925. Units 1 and 2 retired in 1971 and were replaced by Unit 8. Units 3 and 4 retired in 1981, and Unit 5 retired on December 31, 2007. Only two units remain in operation (Units 7 and 8). Unit 6, owned by DEK, has a nameplate capacity of 163 MW. Unit 6 was retired on June 1, 2015. Units 7 and 8 both have a nameplate capacity of 557.7 MW. The facility also contains a coal pile, a hyperbolic cooling tower, and an SCR system.

Unit 5 and Unit 6 share many of the same assets and are housed in the same facilities. Unit 6 is owned by DEK, and Unit 5 is owned by Dynegy. Assets owned by Dynegy are not included in the scope of this project.

3.3 Solar

3.3.1 Crittenden

Crittenden Solar Project is located approximately 5 miles north of Dry Ridge, Kentucky on portions of a 110-acre site. Crittenden has approximately 11,438 panels and a combined rating of approximately 2.7 MW-AC. The project came online in 2017.

3.3.2 Walton

Walton Solar Project is in Keaton County, Kentucky on parts of a 60-acre property. Walton has approximately 17,024 panels and a combined rating of approximately 4 MW-AC. The project came online in 2017.

4.0 DECOMMISSIONING COSTS

1898 & Co. has prepared decommissioning cost estimates for the Plants. When DEK determines that each site should be retired, the above grade equipment and steel structures are assumed to have scrap value to a scrap contractor which will offset a portion of the site decommissioning costs. However, DEK will incur costs of dismantling the Plants and restoration of the sites to the extent that those costs exceed the scrap value of equipment and bulk steel.

The decommissioning costs for each site include the cost to return each site to an industrial condition, suitable for reuse for development of an industrial facility. Included are the costs to dismantle all the assets at the sites, including power generating equipment and BOP facilities, as well as the costs to perform environmental site restoration activities.

For purposes of this study, 1898 & Co. assumed that each site will be dismantled as a single project, allowing the most cost-effective demolition methods to be utilized. A summary of several of the means and methods that could be employed is summarized in the following paragraphs; however, means and methods will not be dictated to the contractor by 1898 & Co. It will be the contractor’s responsibility to determine means and methods that result in safely dismantling the Plants at the lowest possible cost.

Asbestos remediation, as required, would take place prior to commencement of any other demolition activities. Abatement would need to be performed in compliance with all state and federal regulations, including, but not limited to, requirements for sealing off work areas and maintaining negative pressure throughout the removal process. Final clearances and approvals would need to be achieved prior to performing further demolition activities.

High grade assets would then be removed from the site to the extent possible. This would include items such as transformers, transformer coils, circuit breakers, electrical wire, condenser plates and tubes, and heater tubes. High grade assets include precious alloys such as copper, aluminum-brass tubes, stainless steel tubes, and other high value metals occurring in plant systems. High grade asset removal would occur up-front in the schedule, to reduce the potential for theft, to increase cash flow, and for separation of recyclable materials to increase scrap recovery. Methods of removal vary with the location and nature of the asset. Small transformers, small equipment, and wire would likely be removed and shipped as-is for processing at a scrap yard. Large transformers, CT, ST generators, and condensers would likely require some on-site disassembly prior to being shipped to a scrap yard.

Construction and Demolition (“C&D”) waste includes items such as non-asbestos insulation, roofing, wood, drywall, plastics, and other non-metallic materials. C&D waste would typically be segregated from scrap and concrete to avoid cross-contaminating of waste streams or recycle streams. C&D demolition crews could remove these materials with equipment such as excavators equipped with material handling attachments, skid steers, etc. This material would be consolidated and loaded into bulk containers for disposal.

In general, boilers and Heat Recovery Steam Generators (“HRSG”) could be felled and cut into manageable sized pieces on the ground. First the structures around the boilers would need to be removed using excavators equipped with shears and grapples. Stairs, grating, elevators, and other high structures would be removed using an "ultra-high reach" excavator, equipped with shears. Following removal of these structures, the boilers or HRSGs would be felled, using explosive blasts. The boilers would then be dismantled using equipment such as excavators equipped with shears and grapples, and the scrap metal loaded onto trailers for recycling.

After the surrounding structures and ductwork have been removed, the stacks would be imploded, using controlled blasts. Following implosion, the stack liners and concrete would be reduced in size to allow for handling and removal.

BOP structures and foundations would likely be demolished using excavators equipped with hydraulic shears, hydraulic grapples, and impact breakers, along with workers utilizing open flame cutting torches. Steel components would be separated, reduced in size, and loaded onto trailers for recycling. Concrete would be broken into manageable sized pieces and stockpiled for crushing on site. Concrete pieces would ultimately be loaded in a hopper and fed through a crusher to be sized for on-site disposal.

4.1 General Assumptions

The following assumptions are made as the basis of all of the cost estimates:

1. Pricing for all cost estimates is in 2022 dollars.
2. All estimates are budgetary in nature and do not reflect guaranteed costs. Budgetary refers to the nature of the itemized cost estimate being for planning purposes only and not a guarantee.
3. All estimates are based on labor rates from RS means values for a demolition crew B-8 with adjusted rates based on the local site cost index for the Plants.
4. All work will take place in a safe and cost-efficient method.
5. Labor costs are based on a regular 40-hour workweek without overtime.
6. The estimates are inclusive of all costs necessary to properly dismantle and decommission all sites to a marketable or usable condition. For purposes of this Study and the included cost estimates, the sites will be restored to a condition suitable for industrial use. Such sites that are restored for reuse in industrial settings are referred to as brownfield sites.
7. Abatement of asbestos will precede any other work. After final air quality clearances have been reached, demolition can proceed.
8. All facilities will be decommissioned to zero generating output. Existing utilities will remain in place for use by the contractor for the duration of the demolition activities.
9. It is assumed that all of the power stations will be dismantled after all units at a single site are taken out of service, allowing dismantlement of entire sites at once.
10. Soil testing and any other on-site testing has not been conducted for this study.
11. Transmission switchyards and substations outside the boundaries of the plant are not part of the demolition scope.
12. The costs for relocation of transmission lines, or other transmission assets, are specifically excluded from the decommissioning cost estimates.
13. All demolition and abatement activities, including removal of asbestos, will be done in accordance with any and all applicable Federal, State and Local laws, rules and regulations.

14. Any residual oil or sludge in tanks and pipes will be cleaned up by DEK prior to demolition.
15. The scrap value of the equipment is based on the equipment being at the end of its useful life at the time of demolition; therefore, the equipment will not have a value on the grey market for reinstallation. Equipment will have value as scrap only at the time of site demolition.
16. It is assumed that sufficient area to receive, assemble and temporarily store equipment and materials is available.
17. Step-up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates.
18. Demolition will include the removal of all structures, equipment, tanks, conveyer systems, ancillary buildings, and any other associated equipment to two (2) feet below grade.
19. To the extent possible, concrete will be crushed and disposed of on-site. During crushing of the concrete, a large magnet is utilized to remove all rebar. All other non-hazardous material with no scrap value will be disposed of off-site at the nearest landfill.
20. All above grade plant structures and materials such as fire walls, masonry, doors, windows, building finishes, plumbing, HVAC ductwork, lighting fixtures, cable trays, etc., will be disposed of off-site at the nearest landfill.
21. Foundations and ground floor slabs will be removed to two (2) feet below grade. The surface will be graded for drainage using onsite soil and seeding.
22. All pipe supports, and pipe racks will be demolished and scrapped.
23. Three feet of soil beneath the fuel oil tanks is to be removed and replaced with clean fill.
24. Hazardous material abatement is included for all sites as necessary, including asbestos, mercury, and polychlorinated biphenyls (“PCBs”). Lead paint coated materials will be handled by certified personnel compliant with OSHA Standards as necessary but will not be removed prior to demolition. Scrap steel can be taken to scrap brokers with lead paint still intact, and it will not impact the scrap value.
25. All portable tanks will be removed from the site and scrapped, including any propane tanks, oil storage tanks, and waste oil tanks.
26. All chemicals will be consumed or disposed of by the Plant prior to shut down, including process chemicals in equipment, stored chemicals, and laboratory chemicals.
27. Any observable surface spill will be cleaned up.
28. All trash, debris, and miscellaneous waste will be removed and disposed of properly.
29. The substation equipment owned by the Plant including breakers, air break disconnect switch, busbars, grounding cable and transformers up to the interconnection point will be removed.
30. Underground piping will be capped and abandoned in place. Circulating water tunnels will be filled with flowable fill.
31. No environmental costs have been included to address cleanup of contaminated soils, hazardous materials, or other conditions present on-site having a negative environmental impact, other than those specifically listed in these assumptions. No allowances are included for unforeseen environmental remediation activities.
32. Handling and disposal of hazardous material will be performed in compliance with the approved methods of DEK’s Environmental Services Department.

33. Ash ponds and landfills are excluded from the scope of this Study.
34. Storm water ponds will be drained, and the area graded out to allow for natural drainage.
35. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
36. Existing basements will be used to bury non-hazardous debris. Concrete in trenches and basements will be perforated to create drainage. Non-hazardous debris, such as concrete will be crushed and used as clean fill on-site once the capacity of all existing basements has been exceeded. All inert debris will be disposed of on-site. Costs for offsite disposal are included for materials not classified as inert debris.
37. Major equipment, structural steel, CTs, generators, inlet filters, exhaust stacks, transformers, electrical equipment, cabling, wiring, pump skids, above ground piping, and equipment enclosures for the above equipment will be sold for scrap and removed from the Plant site by the demolition contractor. All other demolished materials are considered debris.
38. Valuation and sale of land and all replacement generation costs are excluded from this scope.
39. Spare parts inventories are based on information provided to 1898 & Co. for review.
40. Rolling stock, including rail cars, dozers, plant vehicles, etc. is assumed to be removed by DEK prior to decommissioning.
41. The scope of the costs included in the Study is limited to the decommissioning activities that will occur at the end of useful life of the facilities. Additional on-going costs may be required. These costs are excluded from the cost estimates provided in this Study unless stated otherwise herein.
42. A 20 percent contingency was included on the direct costs in the estimates prepared as part of this Study to cover unknowns.
43. Indirect costs are included in the cost estimate to cover owner expenses such as management trailers, utilities, etc. which may impact the cost of decommissioning each site. An indirect cost of 11 percent was included in the estimates to cover such costs as directed by DEK.
44. Market conditions may result in cost variations at the time of contract execution.
45. The following scrap values were used in the decommissioning cost estimates. The scrap values are based upon the 12-month average of American Metal Market prices for June 2021 to May 2022 (i.e., one calendar year). These values include the cost to haul the scrap via truck and/or rail to the scrap market indicated below.

Table 4-1: Scrap Pricing

Plant	Scrap Market Location	Steel Scrap Value ($/net ton)	Copper Scrap Value ($/pound)	Aluminum Scrap Value ($/pound)
Crittenden Solar	Chicago	($383.96)	($3.32)	($0.48)
East Bend	Cincinnati	($386.06)	($3.32)	($0.48)
Miami Fort	Cincinnati	($389.21)	($3.32)	($0.48)
Walton Solar	Cincinnati	($387.81)	($3.32)	($0.48)
Woodsdale	Chicago	($384.51)	($3.31)	($0.48)

Table 4-2: Stainless Steel Scrap Pricing

Plant	Scrap Market Location	Stainless Scrap Value ($/net ton)
Miami Fort	Cleveland	($1,926.35)

4.2 Site Specific Assumptions

The following assumptions were made specific to each site, in addition to the general assumptions listed above.

4.2.1 Crittenden Solar

1. All fencing will be removed, and the site will be cleared of debris at end of decommissioning.
2. Costs for grading and seeding are included in the decommissioning cost estimate.
3. Roads will be removed.

4.2.2 East Bend

1. Due to the vintage of the Plant, lead-based paint is assumed to be present.
2. The coal pile area will be excavated to a depth of one foot, graded, capped, and covered with imported topsoil.
3. The landfill is not included in the scope of this Study.
4. Costs of removal of the mooring cells and unloading facilities are included in the Study.
5. It is assumed that no material was removed from the site during construction; therefore, borrow material is assumed to be available on-site to be used to backfill the basement.
6. Condenser tube material is assumed to be copper based on discussion with DEK plant personnel.

4.2.3 Miami Fort

1. A full demo of the Miami Fort power plant is assumed to take place after the retirement of all of the currently operating units owned by Dynegy.
2. The full demolition costs includes the assets owned by DEK and 13 percent of the cost of removal of the common facilities according to DEK's ownership. These assets include Unit 6 boiler and ST, two conveyors (#12 and conveyer G), Unit 5 coal crusher, Unit 5 vacuum pump, and the exhaust stack. The building housing the four STs is assumed to be partially owned by DEK at 25 percent, therefore, 25 percent of the demolition costs are included.
3. Costs for removal of the limestone handling facilities are not included.
4. The chimney is assumed to be imploded upon the retirement of all the currently operating units owned by Dynegy due to the complexity and larger expense that would be required to remove the chimney in a conventional manner with adjacent units still in operation.
5. A $200,000 per year Maintenance Agreement fee in place until 2025 is included as a lump sum cost, as requested by DEK.

6. It is assumed that no material was removed from the site during construction; therefore, borrow material is assumed to be available on-site to be used to backfill the basement.
7. Due to the vintage of the Plant, lead-based paint is assumed to be present.
8. Mooring cells and barge unloading facilities are not included in the scope of this Study.
9. All asbestos has been removed from Unit 6 since last study.
10. Coal conveyor #11 has been removed since last study.
11. All oil and fluids have been removed from Unit 6. Transformer-rectifier sets on the precipitators were drained and removed.
12. Condenser tube material is assumed to be stainless steel.

4.2.4 Walton Solar

1. All fencing will be removed, and the site will be cleared of debris at end of decommissioning.
2. Costs for grading and seeding are included in the decommissioning cost estimate.
3. Roads will be removed.

4.2.5 Woodsdale

1. The Madison Plant northwest of the Woodsdale Plant is not included in the scope of this Study.
2. No further work is necessary to restore the area where Unit 7 through Unit 12 were planned.
3. Due to the vintage of the plant, it is assumed no asbestos or lead paint is present.
4. Two fuel oil tanks have been constructed since the previous Study. Costs for removal of these tanks are included.

5.0 RESULTS

1898 & Co. has prepared cost estimates in 2022 dollars for the decommissioning of the Plants. These costs are summarized in the following table. When DEK determines that the Plants should be retired, the above grade equipment and steel structures are assumed to have sufficient scrap value to a scrap contractor to offset a portion of the decommissioning costs. DEK will incur costs in the demolition and restoration of the sites less the salvage value of equipment and bulk recycled metals. Additionally, DEK's on-site inventory was taken into consideration for the demolition costs. For the CT facility, a salvage value of 25 percent was assumed. For the other Plants, 10 percent of the inventory was assumed to be salvageable. The CT facility was assumed to have a higher inventory salvage value because spare parts for CT are more marketable and can be more easily resold to other owners/operators at a higher premium than just the scrap price of the material.

Table 5-1: Decommissioning Cost Summary (2022$)

Plant	Gross Decom Cost	Inventory Cost	Salvage Credits	Inventory Credits	Net Project Cost
Crittenden Solar	$ 630,700	-	$ (218,400)	-	$ 412,300
East Bend	$ 47,573,000	$ 9,084,000	$ (17,034,000)	$ (908,000)	$ 38,715,000
Miami Fort	$ 8,522,000	-	$ (3,635,000)	-	$ 4,887,000
Walton Solar	$ 880,500	-	$ (294,300)	-	$ 586,200
Woodsdale	$ 14,452,000	$ 5,967,000	$ (7,600,000)	$ (1,492,000)	$ 11,327,000

The total project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development as an industrial facility. Included are the costs to dismantle all power generating equipment and balance of plant facilities and, where applicable, to perform environmental site restoration activities. Further details including estimates for the major cost categories of each plant estimate are provided in Appendix B.

APPENDIX A – COST ESTIMATE SUMMARIES

Table A-1
Crittenden Solar
Solar Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Crittenden Solar						
Solar Farm						
O&M Building	$ 3,600	$ 4,300	$ -	$ -	$ 7,900	$ -
Solar Panel Removal/Recycling	$ 64,100	$ 76,400	$ 12,100	$ -	$ 152,600	$ -
Panel Supports/Rack	$ 66,300	$ 79,000	$ -	$ -	$ 145,300	$ -
Electrical & Wiring	$ 6,100	$ 7,300	$ -	$ -	$ 13,400	$ -
Site Restoration	$ 18,900	$ 22,600	$ -	$ 120,100	$ 161,600	$ -
On-site Concrete Crushing and Removal	$ -	$ -	$ 400	$ -	$ 400	$ -
Debris	$ -	$ -	$ 200	$ -	$ 200	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (218,400)
Subtotal	**$ 159,000**	**$ 189,600**	**$ 12,700**	**$ 120,100**	**$ 481,400**	**$ (218,400)**
Crittenden Solar Subtotal	**$ 159,000**	**$ 189,600**	**$ 12,700**	**$ 120,100**	**$ 481,400**	**$ (218,400)**
TOTAL DECOM COST (CREDIT)					**$ 481,400**	**$ (218,400)**
PROJECT INDIRECTS (11%)					**$ 53,000**	
CONTINGENGY (20%)					**$ 96,300**	
TOTAL PROJECT COST (CREDIT)					**$ 630,700**	**$ (218,400)**
TOTAL NET PROJECT COST (CREDIT)					**$ 412,300**	

Table A-2
East Bend
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
East Bend						
Unit 2						
Boiler	$ 3,326,000	$ 3,238,000	$ -	$ -	$ 6,564,000	$ -
Steam Turbine & Building	$ 1,711,000	$ 1,666,000	$ -	$ -	$ 3,377,000	$ -
Precipitators	$ 1,314,000	$ 1,279,000	$ -	$ -	$ 2,593,000	$ -
SCR	$ 1,028,000	$ 1,001,000	$ -	$ -	$ 2,029,000	$ -
Scrubber / FGD	$ 577,000	$ 562,000	$ -	$ -	$ 1,139,000	$ -
Cooling Towers & Basin	$ 995,000	$ 968,000	$ -	$ -	$ 1,963,000	$ -
Stacks	$ 461,000	$ 449,000	$ -	$ -	$ 910,000	$ -
GSU & Foundation	$ 82,000	$ 79,000	$ -	$ -	$ 161,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 578,000	$ -	$ 578,000	$ -
Debris	$ -	$ -	$ 82,000	$ -	$ 82,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (15,533,000)
Subtotal	**$ 9,494,000**	**$ 9,242,000**	**$ 660,000**	**$ -**	**$ 19,396,000**	**$ (15,533,000)**
Handling						
Coal Handling Facilites	$ 1,637,000	$ 1,594,000	$ -	$ -	$ 3,231,000	$ -
Coal Storage Area Restoration	$ -	$ -	$ -	$ 2,956,000	$ 2,956,000	$ -
Limestone Handling Facilities	$ 194,000	$ 189,000	$ -	$ -	$ 383,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 13,000	$ -	$ 13,000	$ -
Debris	$ -	$ -	$ 3,000	$ -	$ 3,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (739,000)
Subtotal	**$ 1,831,000**	**$ 1,783,000**	**$ 16,000**	**$ 2,956,000**	**$ 6,586,000**	**$ (739,000)**
Common						
Cooling Water Intakes and Circulating Water Pumps	$ 58,000	$ 56,000	$ -	$ 830,000	$ 944,000	$ -
Roads	$ 363,000	$ 353,000	$ -	$ -	$ 716,000	$ -
All BOP Buildings	$ 781,000	$ 761,000	$ -	$ -	$ 1,542,000	$ -
Fuel Equipment	$ 43,000	$ 42,000	$ -	$ -	$ 85,000	$ -
All Other Tanks	$ 223,000	$ 217,000	$ -	$ -	$ 440,000	$ -
Transformers & Foundation	$ 26,000	$ 26,000	$ -	$ -	$ 52,000	$ -
Transformer Oil	$ -	$ -	$ -	$ 125,000	$ 125,000	$ -
Transformers Pad and Soil Removal	$ -	$ -	$ -	$ 24,000	$ 24,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 70,000	$ 70,000	$ -
Refractory Cleanup	$ -	$ -	$ -	$ 7,000	$ 7,000	$ -
Plant Wash Down and Cleaup	$ -	$ -	$ -	$ 56,000	$ 56,000	$ -
Fuel Oil Tank Cleanup	$ -	$ -	$ -	$ 35,000	$ 35,000	$ -
Fuel Oil Soil Remediation	$ -	$ -	$ -	$ 86,000	$ 86,000	$ -
Pond Closure	$ -	$ -	$ -	$ 3,996,000	$ 3,996,000	$ -
Concrete Removal, Crushing, & Disposal	$ -	$ -	$ 70,000	$ -	$ 70,000	$ -
Grading & Seeding	$ -	$ -	$ -	$ 2,075,000	$ 2,075,000	$ -
Debris	$ -	$ -	$ 10,000	$ -	$ 10,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (762,000)
Subtotal	**$ 1,494,000**	**$ 1,455,000**	**$ 80,000**	**$ 7,304,000**	**$ 10,333,000**	**$ (762,000)**
East Bend Subtotal	**$ 12,819,000**	**$ 12,480,000**	**$ 756,000**	**$ 10,260,000**	**$ 36,315,000**	**$ (17,034,000)**
TOTAL DECOM COST (CREDIT)					**$ 36,315,000**	**$ (17,034,000)**
PROJECT INDIRECTS (11%)					**$ 3,995,000**	
CONTINGENGY (20%)					**$ 7,263,000**	
INVENTORY					**$ 9,084,000**	**$ (908,000.00)**
TOTAL PROJECT COST (CREDIT)					**$ 56,657,000**	**$ (17,942,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 38,715,000**	

Table A-3
Miami Fort
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Miami Fort						
Unit 6						
Boiler	$ 1,349,000	$ 882,000	$ -	$ -	$ 2,231,000	$ -
Steam Turbine & Building	$ 606,000	$ 396,000	$ -	$ -	$ 1,002,000	$ -
NSCR	$ 128,000	$ 83,000	$ -	$ -	$ 211,000	$ -
Stacks	$ 225,000	$ 147,000	$ -	$ -	$ 372,000	$ -
Cooling Water Intakes and Circulating Water Pumps	$ 23,000	$ 15,000	$ -	$ -	$ 38,000	$ -
GSU & Foundation	$ 66,000	$ 43,000	$ -	$ -	$ 109,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 138,000	$ -	$ 138,000	$ -
Debris	$ -	$ -	$ 40,000	$ -	$ 40,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,576,000)
Subtotal	**$ 2,397,000**	**$ 1,566,000**	**$ 178,000**	**$ -**	**$ 4,141,000**	**$ (3,576,000)**
Handling						
Coal Handling Facilites	$ 45,000	$ 29,000	$ -	$ -	$ 74,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (54,000)
Subtotal	**$ 45,000**	**$ 29,000**	**$ 1,000**	**$ -**	**$ 75,000**	**$ (54,000)**
Common						
Maintenance Agreement Fee	$ 600,000	$ -	$ -	$ -	$ 600,000	$ -
Tanks	$ 1,000	$ 1,000	$ -	$ -	$ 2,000	$ -
Transformers Pad and Soil Removal	$ -	$ -	$ -	$ 19,000	$ 19,000	$ -
Refractory Cleanup	$ -	$ -	$ -	$ 8,000	$ 8,000	$ -
Plant Wash Down and Cleanup	$ -	$ -	$ -	$ 62,000	$ 62,000	$ -
Mercury and Universal Waste Cleanup	$ -	$ -	$ -	$ 20,000	$ 20,000	$ -
Nuclear Device Cleanup	$ -	$ -	$ -	$ 9,000	$ 9,000	$ -
Grading & Seeding	$ -	$ -	$ -	$ 1,569,000	$ 1,569,000	$ -
Subtotal	**$ 601,000**	**$ 1,000**	**$ -**	**$ 1,687,000**	**$ 2,289,000**	**$ (5,000)**
Miami Fort Subtotal	**$ 3,043,000**	**$ 1,596,000**	**$ 179,000**	**$ 1,687,000**	**$ 6,505,000**	**$ (3,635,000)**
TOTAL DECOM COST (CREDIT)					**$ 6,505,000**	**$ (3,635,000)**
PROJECT INDIRECTS (11%)					**$ 716,000**	
CONTINGENGY (20%)					**$ 1,301,000**	
TOTAL PROJECT COST (CREDIT)					**$ 8,522,000**	**$ (3,635,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 4,887,000**	

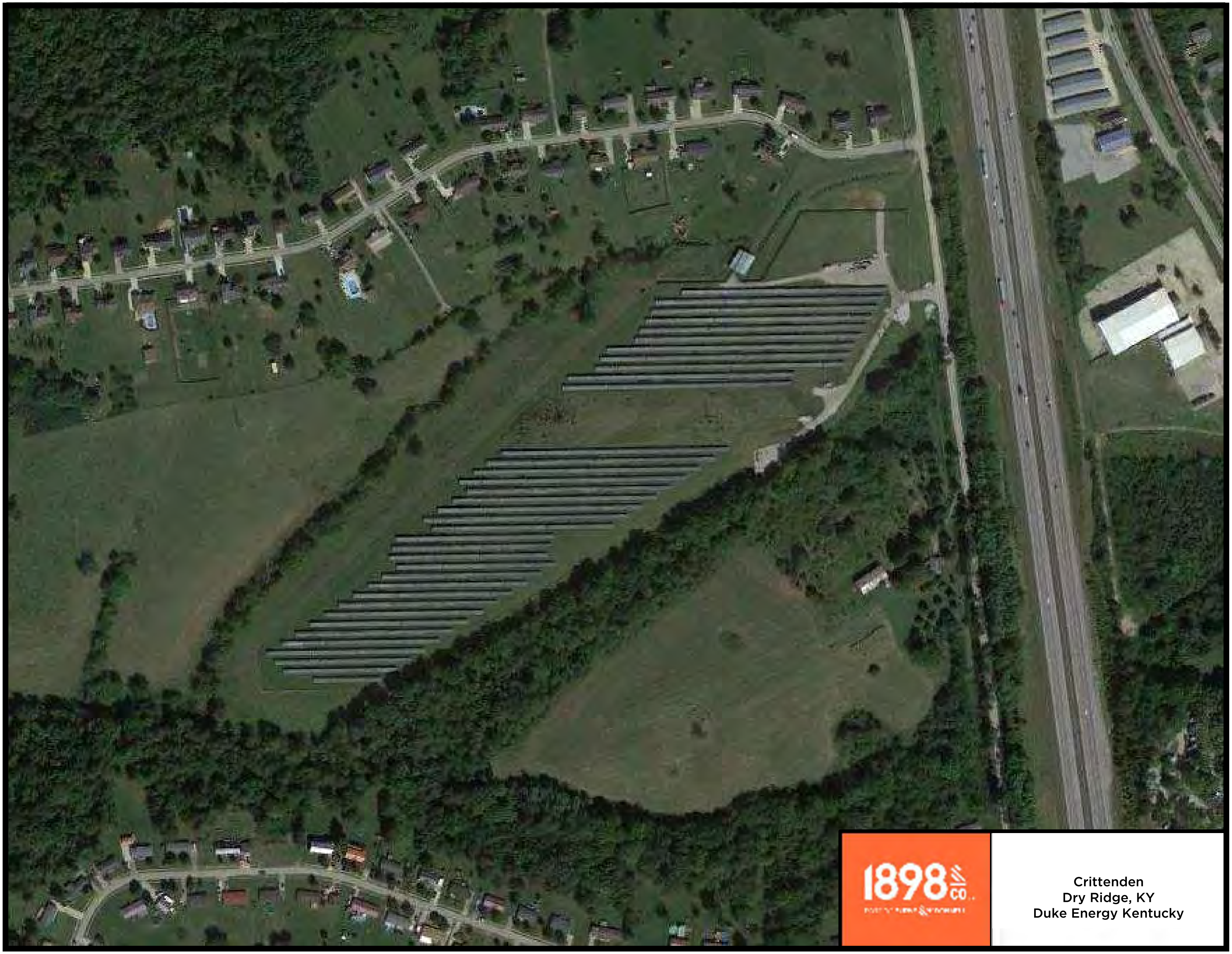
Table A-4
Walton Solar
Solar Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Walton Solar						
Solar Farm						
Solar Panel Removal/Recycling	$ 95,400	$ 113,700	$ 16,100	$ -	$ 225,200	$ -
Panel Supports/Rack	$ 98,700	$ 117,700	$ -	$ -	$ 216,400	$ -
Electrical & Wiring	$ 6,300	$ 7,500	$ -	$ -	$ 13,800	$ -
Site Restoration	$ 24,400	$ 29,000	$ -	$ 162,900	$ 216,300	$ -
On-site Concrete Crushing and Removal	$ -	$ -	$ 400	$ -	$ 400	$ -
Debris	$ -	$ -	$ 100	$ -	$ 100	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (294,300)
Subtotal	**$ 224,800**	**$ 267,900**	**$ 16,600**	**$ 162,900**	**$ 672,200**	**$ (294,300)**
Walton Solar Subtotal	**$ 224,800**	**$ 267,900**	**$ 16,600**	**$ 162,900**	**$ 672,200**	**$ (294,300)**
TOTAL DECOM COST (CREDIT)					**$ 672,200**	**$ (294,300)**
PROJECT INDIRECTS (11%)					**$ 73,900**	
CONTINGENGY (20%)					**$ 134,400**	
TOTAL PROJECT COST (CREDIT)					**$ 880,500**	**$ (294,300)**
TOTAL NET PROJECT COST (CREDIT)					**$ 586,200**	

Table A-5
Woodsdale
Decommissioning Cost Summary

	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Woodsdale						
Unit 1-6						
CTs	$ 2,769,000	$ 1,811,000	$ -	$ -	$ 4,580,000	$ -
Stacks	$ 45,000	$ 30,000	$ -	$ -	$ 75,000	$ -
Switchgear & Electrical	$ 6,000	$ 4,000	$ -	$ -	$ 10,000	$ -
GSU & Foundation	$ 151,000	$ 99,000	$ -	$ -	$ 250,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 46,000	$ -	$ 46,000	$ -
Debris	$ -	$ -	$ 52,000	$ -	$ 52,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,370,000)
Subtotal	**$ 2,971,000**	**$ 1,944,000**	**$ 98,000**	**$ -**	**$ 5,013,000**	**$ (6,370,000)**
Common						
Water Treatment Equipment and Piping	$ 429,000	$ 281,000	$ -	$ -	$ 710,000	$ -
Roads	$ 290,000	$ 189,000	$ -	$ -	$ 479,000	$ -
All BOP Buildings	$ 496,000	$ 325,000	$ -	$ -	$ 821,000	$ -
Fuel Equipment	$ 550,000	$ 360,000	$ -	$ 410,000	$ 1,320,000	$ -
All Other Tanks	$ 271,000	$ 177,000	$ -	$ -	$ 448,000	$ -
Transformers & Foundation	$ 34,000	$ 22,000	$ -	$ -	$ 56,000	$ -
Mercury & Universal Waste Disposal	$ -	$ -	$ -	$ 32,000	$ 32,000	$ -
Transformer Oil Cleanup	$ -	$ -	$ -	$ 134,000	$ 134,000	$ -
Transformer Pad and Soil Removal	$ -	$ -	$ -	$ 55,000	$ 55,000	$ -
Fuel Oil Tank Cleaning	$ -	$ -	$ -	$ 56,000	$ 56,000	$ -
Fuel Oil Line Flushing/Cleaning	$ -	$ -	$ -	$ 37,000	$ 37,000	$ -
Pond Closure	$ -	$ -	$ -	$ 310,000	$ 310,000	$ -
Concrete Removal, Crushing, & Disposal	$ -	$ -	$ 73,000	$ -	$ 73,000	$ -
Grading & Seeding	$ -	$ -	$ -	$ 1,481,000	$ 1,481,000	$ -
Debris	$ -	$ -	$ 7,000	$ -	$ 7,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (1,230,000)
Subtotal	**$ 2,070,000**	**$ 1,354,000**	**$ 80,000**	**$ 2,515,000**	**$ 6,019,000**	**$ (1,230,000)**
Woodsdale Subtotal	**$ 5,041,000**	**$ 3,298,000**	**$ 178,000**	**$ 2,515,000**	**$ 11,032,000**	**$ (7,600,000)**
TOTAL DECOM COST (CREDIT)					**$ 11,032,000**	**$ (7,600,000)**
PROJECT INDIRECTS (11%)					**$ 1,214,000**	
CONTINGENGY (20%)					**$ 2,206,000**	
INVENTORY ADJUSTMENT					**$ 5,967,000**	**$ (1,492,000)**
TOTAL PROJECT COST (CREDIT)					**$ 20,419,000**	**$ (9,092,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 11,327,000**	

APPENDIX B – PLANT AERIALS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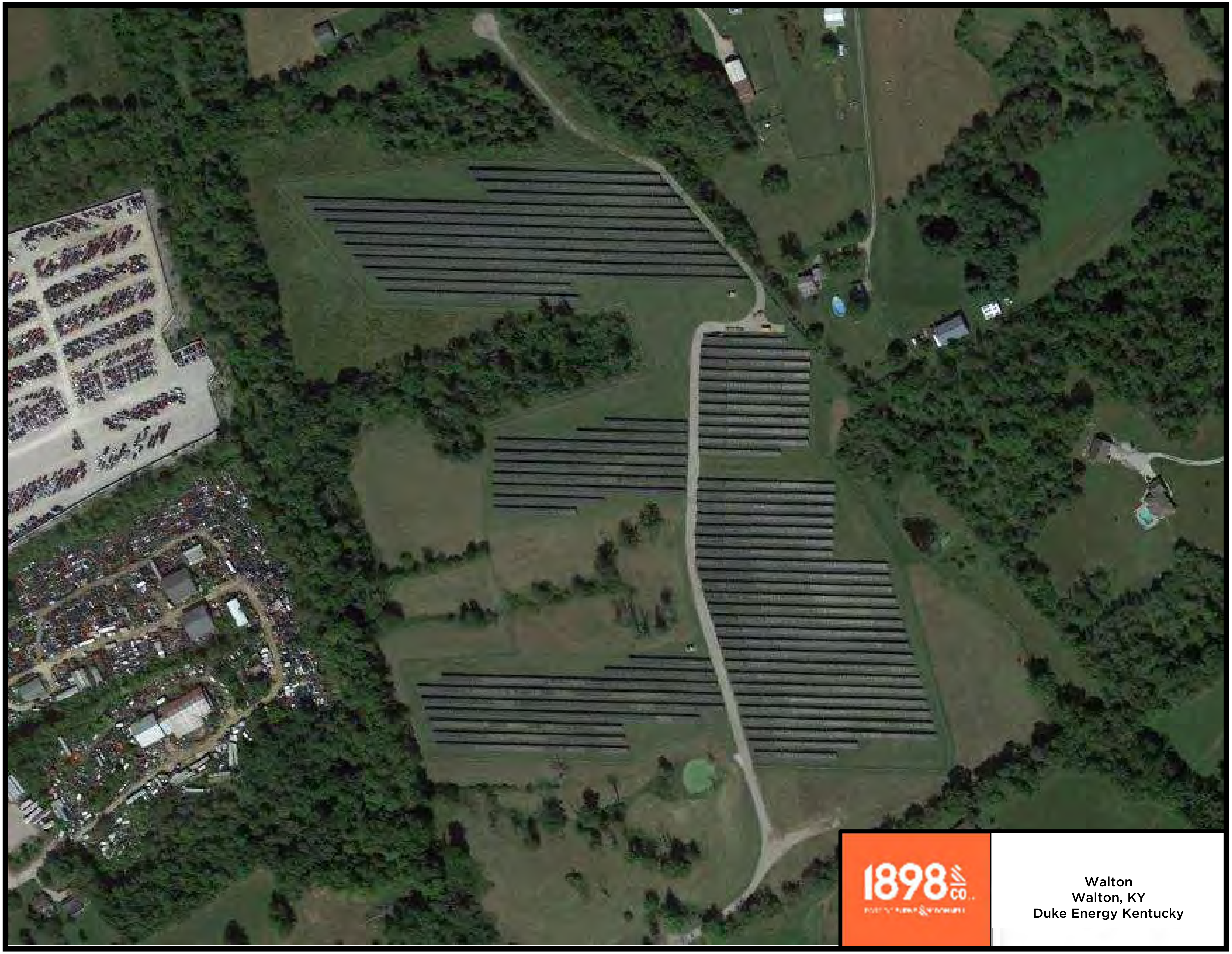
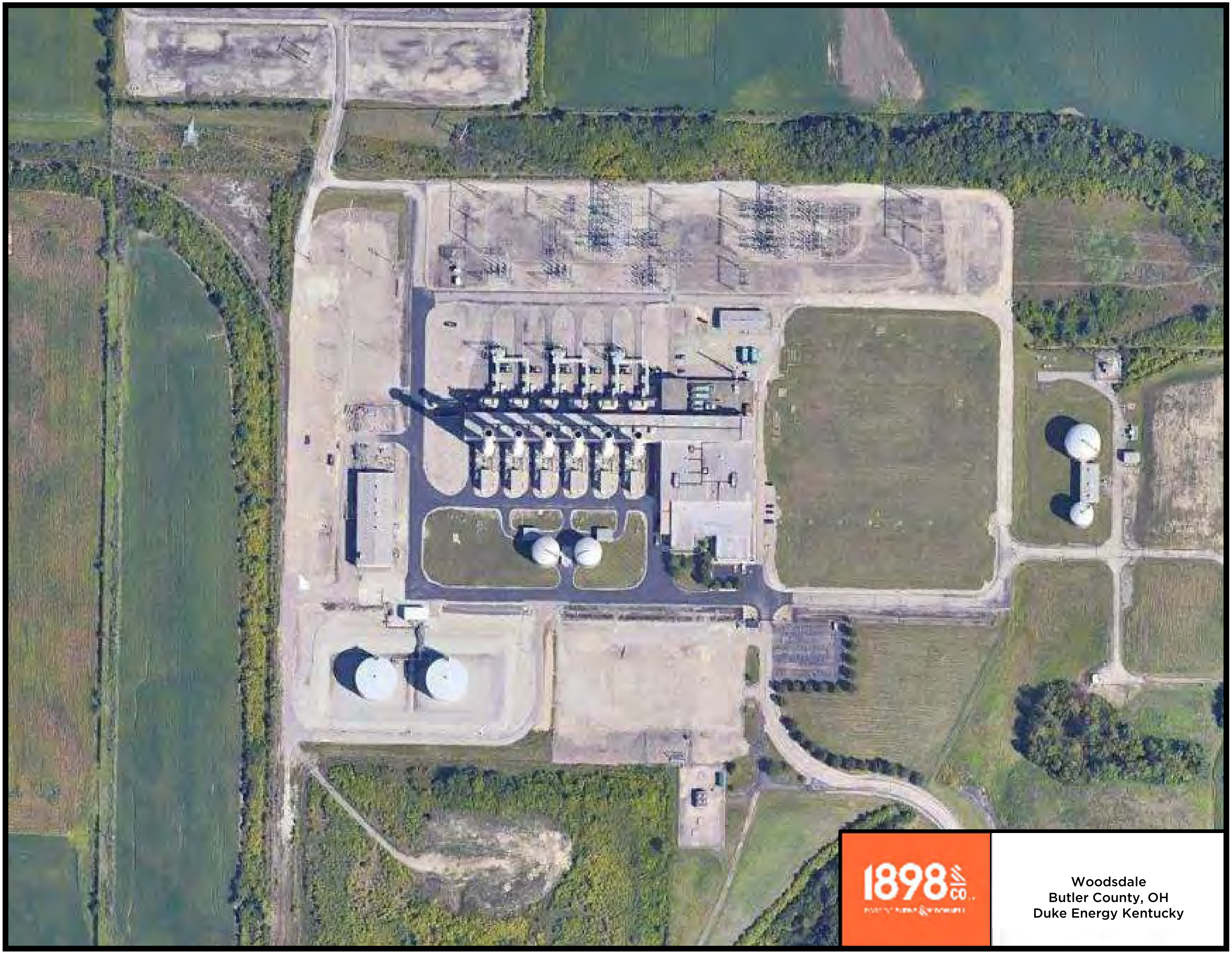
Dry Ridge, KY
Duke Energy Kentucky

East Bend
Boone County, KY
Duke Energy Kentucky

1898 & Co.

Miami Fort
Hamilton County, OH
Duke Energy Kentucky


1898 & CO.
Walton
Walton, KY
Duke Energy Kentucky


1898 & CO.
Woodsdale
Butler County, OH
Duke Energy Kentucky

9400 Ward Parkway

Kansas City, MO

816-605-7800

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

SARAH E. LAWLER

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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ATTACHMENTS:

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Sarah E. Lawler and my business address is 139 East Fourth Street, Cincinnati, Ohio 45202.

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

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

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATION AND PROFESSIONAL EXPERIENCE.

A. I earned a Bachelor of Science in Accountancy from Miami University, Oxford, Ohio, in 1993. I am also a Certified Public Accountant. I began my career in September 1993 with Coopers & Lybrand, L.L.P., as an audit associate and progressed to a senior audit associate. In August 1997, I moved to Kendle International Inc., where I held various positions in the accounting department, ultimately being promoted to Corporate Controller. In August 2003, I began working for Cinergy Corp., the parent of Duke Energy Ohio, as External Reporting Manager, where I was responsible for the Company's Securities & Exchange Commission filings. In August 2005, I moved into the role of Manager, Budgets & Forecasts. In June 2006, following the merger between Cinergy Corp. and Duke Energy, I became Manager, Financial Forecasting. In February 2015, I was promoted to Utility Strategy Director, Midwest, where I was responsible for the preparation of business plans and other internal managerial reporting for Duke Energy Kentucky and Duke Energy Ohio. In December 2017, I assumed the role of Director, Rates and Regulatory Planning where I was responsible for the preparation of financial and accounting data used in Duke Energy Kentucky and Duke Energy Ohio retail rate filings and changes in various other rate recovery mechanisms. In May 2020, I was promoted to my current role of Vice President, Rates & Regulatory Strategy where I am responsible for all state and federal regulatory rate matters involving Duke Energy Kentucky and Duke Energy Ohio.

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

A. Yes. I have previously testified in a number of cases before the Commission and other regulatory commissions.

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

A. On behalf of Duke Energy Kentucky, I provide some background for its request to increase electric base revenues and the drivers behind the Company's application. I support the reasonableness of the Company's proposed rate increase and sponsor Filing Requirement (FR) 16(1)(b)(1) and FR 16(9) to comply with the Commission's filing requirements. I support the Company's proposal to implement several new tariff offerings and rate mechanisms and the deferral authority necessary to support those mechanisms. I also support the Company's proposal to make modifications to the Fuel Adjustment Clause (FAC) to reduce monthly volatility on customer bills.

II. BACKGROUND AND DRIVERS FOR REQUESTED RATE INCREASE

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

A. The Company's current base rates for electric service were initially approved by the Commission on April 27, 2020, and then amended upon rehearing on October 16, 2020, in Case No. 2019-00271 (2019 Rate Case). The test period in that proceeding was the forecasted twelve months ended March 31, 2021, and the rate base and capitalization used in that case was the thirteen-month average for the period ending March 31, 2021. The current rates went into effect on May 1, 2020, and then were updated upon rehearing on October 29, 2020.

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

A. The Company's Application in this case requests an increase in its overall electric base revenues based on the forecasted twelve-month period July 1, 2023, through June 30, 2024.

Q. WHY IS DUKE ENERGY KENTUCKY FILING AN ELECTRIC BASE RATE CASE AT THIS TIME?

A. For the forecasted test period, the Company is projecting that the earned return on its investment in its electric distribution system is not providing fair and reasonable compensation to its investors. As a result, the Company is requesting an approximate $75.2 million increase in electric base revenues in order to provide fair and reasonable compensation to its investors.

The most significant driver of this requested increase is an increase in depreciation expense. Depreciation expense is partly higher as a result of additional investments since the time of the last electric base rate case. Net rate base has grown by approximately $300 million since the time of the Company's last electric base rate case as a result of much needed investments for the Company to continue to provide safe and reliable service to its customers. Depreciation expense is also higher because of the impacts of the Commission denying the Company's depreciation study its last electric base rate case. Finally, this is also in part driven by the need to align the depreciable lives of the Company's power plants, East Bend and Woodsdale, with the end of their service lives. The Company's requested return on these investments and associated property taxes is also a significant driver of the requested increase.

Q. CAN YOU EXPLAIN WHY DEPRECIATION EXPENSE IS SUCH A SIGNIFICANT DRIVER OF THE OVERALL REQUESTED REVENUE REQUIREMENT?

A. Yes. The Company is proposing to increase depreciation expense approximately $35 million as compared to what is currently in base rates today. This is a result of three primary factors.

First, in the Company's last electric base rate case, the Commission denied the Company's request to update its depreciation rates. Because of this, if the Company does not update depreciation rates in this proceeding, there will be an extremely significant remaining net book value remaining uncollected from customers at the end of the service lives of the Company's two power plants, East

Bend and Woodsdale. Duke Energy Kentucky has been and must continue to make investments in these power plants to ensure safe, reliable service to its customers. When capital investments are made to assets and their remaining useful life is not extended because of those investments, the depreciation rates must be adjusted to ensure that the total asset value is fully depreciated (less salvage) at the end of the service lives of the assets. Because this did not happen in the Company's 2019 rate case, current depreciation rates do not fully depreciate these assets by the end of their service lives. In fact, at current depreciation rates today, and without adding any future capital investments to these plants, the remaining net book value (NBV) of East Bend as of December 31, 2041 will be approximately $107 million and the remaining NBV of Woodsdale as of December 31, 2032 will be approximately $54 million. Again, this is just based on depreciating the assets currently on the books as of December 31, 2021 and does not take into account any future capital investments that will need to be made at these plants to keep them running safely and reliably until retired. It also assumes that current depreciation rates reflect an appropriate cost of removal rate to establish a cost of removal reserve at the end of the assets' useful lives that is sufficient to cover actual costs of removal.

Second, as discussed in the testimonies of Company witnesses Amy B. Spiller, Lisa M. Quilici, William C. Luke, and Scott Park, East Bend is now currently projected to retire in 2035, six years earlier than its originally planned retirement date of 2041. In order to align the depreciation rates with this new estimated retirement date, depreciation expense has to increase. This is driving approximately $11 million of the total $35 million increase in depreciation expense.

Partially mitigating this increase is the fact that the estimated retirement date of Woodsdale is now projected to be 2040, eight years later than its originally planned retirement date. Included in the $35 million increase in depreciation expense is an approximately $7 million decrease associated with this extension of useful life.

Therefore, the net impact to depreciation expense as a result in the change in service lives of East Bend and Woodsdale is approximately $4 million. Duke Energy Kentucky needs to properly align East Bend's and Woodsdale's depreciation rates with their anticipated service lives to avoid intergenerational subsidies and to protect and minimize the amount that future customers could have to pay for any post-retirement undepreciated plant remaining after the generating assets' retirements, as well as for their replacement resource(s).

Third, as discussed previously, the Company's rate base has increased approximately $300 million since the time of its last electric base rate case. Depreciation expense associated with these new investments is also driving the increase in depreciation expense.

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

A. Yes. Since the 2019 Rate Case, the cost of capital has increased. The Company's current weighted average cost of capital approved in the 2019 rate case is 6.412 percent. The Company is requesting a weighted average cost of capital of 7.526 percent in this current proceeding. The return on equity (ROE) authorized in the last case was 9.25 percent. The long-term debt rate approved in that case was 4.028 percent and the short-term debt rate approved was 1.710 percent. In this proceeding, the Company is requesting a ROE of 10.35 percent, a 4.377 percent long-term debt rate and a 4.739 percent short-term debt rate. Company witnesses Joshua C. Nowak and Christopher R. Bauer will discuss the market drivers behind these increases in the Company's cost of capital.

Q. PLEASE DESCRIBE HOW THE COMPANY'S REQUESTED INCREASE IN BASE RATES WILL IMPACT CUSTOMERS' BILLS?

A. The Company's proposed overall revenue requirement is an increase of approximately 17.8 percent over current total retail revenue.[1] As discussed in the testimony of Company witness James E. Ziolkowski, Duke Energy Kentucky is proposing to allocate the overall revenue requirement so that existing subsidies and excesses between rate classes are not exacerbated and, even reduced where possible. As a result of the cost-of-service study, the allocation of the proposed revenue requirement is such that residential customers will see an approximate 21.2 percent increase in their overall bills. Non-residential distribution customers will see an approximate 15.8 percent increase on their bills and non-residential transmission customers will see an approximate 10 percent increase on their bills.

III. NEW RATE PROGRAMS AND MECHANISMS

A. Electric Vehicle Programs

Q. CAN YOU SUMMARIZE THE ELECTRIC VEHICLE PROGRAMS THE COMPANY IS PROPOSING IN THIS PROCEEDING?

A. Yes. The Company is proposing two new programs to encourage electric vehicle (EV) adoption and to assist customers and the broader public in the transition to

[1] *See* Schedule M, page 1 of 1, line 37.

electric transportation infrastructure. Company witness Mr. Cormack C. Gordon explains in more detail in his testimony the proposal for these two new EV programs and supporting tariffs: 1) Electric Vehicle Site Make Ready Service (Rate MRC); and 2) Electric Vehicle Service Equipment (Rate EVSE); (collectively the EV Programs). Company witness Mr. Bruce L. Sailers supports the detailed tariffs associated with the EV Programs.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER ITS COSTS ASSOCIATED WITH THE RATE MRC PROGRAM?

A. As discussed in Mr. Gordon's testimony, the Company proposes to provide credits to customers to assist them with the expenses of the make ready infrastructure needs associated with electric vehicles. As discussed by Company witness Ms. Danielle L. Weatherston, the Company asks that the Commission approve regulatory asset treatment of these costs. Duke Energy Kentucky would then seek recovery of this regulatory asset in a future rate proceeding. The Company also requests that it be allowed to accrue and record in the regulatory asset account carrying costs at the cost of debt approved in this proceeding.

Q. WHY SHOULD THE COMPANY BE ALLOWED TO RECORD CARRYING COSTS AT THE COST OF DEBT FOR THIS REGULATORY ASSET?

A. The Company is simply requesting to be made whole for the time value of money related to these expenses. Such an accrual is appropriate because the subject costs are necessarily incurred by the Company. Guidance from FERC and prudent accounting principles support the inclusion of carrying costs as part of the subject regulatory asset until the Commission determines whether the deferred costs are recoverable.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER ITS COSTS ASSOCIATED WITH THE RATE EVSE PROGRAM?

A. The assets that the Company owns to support the EVSE program will not be included in rate base in electric distribution rates. Like some of the Company's lighting assets, even though the assets are recorded to plant accounts on the Company's books and records, an adjustment is made for rate-making purposes to exclude these assets from rate base. The Company calculates a levelized fixed charge rate (LFCR) and bills the customer for the cost of the program based on the LFCR, such that the customers utilizing the program are the only customers paying for the cost of the program. Similar to the lighting assets discussed above, the Rate EVSE tariff costs associated with individual customer installations will be recovered through monthly billing to participating customers such that only customers utilizing the program are the only customers paying for the cost of the program.

B. Clean Energy Connection Program

Q. CAN YOU SUMMARIZE THE CLEAN ENERGY CONNECTION PROGRAM THAT THE COMPANY IS PROPOSING IN THIS PROCEEDING?

A. The Clean Energy Connection (CEC) Program is a community solar program through which participating customers can voluntarily subscribe to a share of new solar energy facility(s). The CEC Program would allow Duke Energy Kentucky to satisfy increasing customer demand for renewable energy and will enable the Company to provide affordable clean energy to all its customers.

The CEC Program represents the next evolution of Duke Energy Kentucky's commitment to increasing renewable generation and providing innovative pricing solutions for our customers. The CEC Program is structured to maximize the benefits to the entire Duke Energy Kentucky system and to share those benefits with non-participating customers.

The CEC Program will enable the construction of discrete solar projects. Company witness Mr. Paul L. Halstead provides detailed testimony supporting this program and explains the subscription fees that participating customers will pay and bill credits they will receive as part of the CEC Program.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO RECOVER ITS COSTS ASSOCIATED WITH THIS PROGRAM.

A. The first project, upon approval, could come online as early as 2025. The Company will file a Certificate of Public Convenience and Necessity in a separate proceeding for Commission approval. Once approved by the Commission, the Company proposes to include the asset in rate base in a future base rate case proceeding. Subscription fees net of bill credits will be recorded to miscellaneous revenues and those miscellaneous revenues will serve as an offset to the requested revenue requirement in that proceeding. This rate making treatment will ensure that if the program is fully subscribed, only those customers participating in the program will pay for the assets. If the program is not fully subscribed, the assets are intended to add solar generation to the Company's overall system and will displace fossil-fueled generation, thereby lowering emissions and expected fuel expenses for all customers, as Mr. Halstead explains in his testimony.

Q. IS THE COMPANY PROPOSING TO INCLUDE ANY COSTS ASSOCIATED WITH THIS PROGRAM IN BASE RATES IN THIS PROCEEDING.

A. No.

C. <u>Rider FAC</u>

Q. DESCRIBE THE COMPANY'S FUEL ADJUSTMENT CLAUSE (FAC)?

A. As provided for in 807 KAR 5:056, Duke Energy Kentucky recovers its actual fuel costs attributable to serving its retail load through a combination of amounts recovered in base rates and a separate rider, namely, the fuel adjustment clause rider (Rider FAC).

Each month, the Company calculates the cost of fuel burned in its generating facilities and any energy purchased in the market attributable to its retail load. The total cost of burning fuel and purchasing energy for its retail load in that month is divided by the actual kWh sales during that same month. The result is a rate, expressed as a $/kWh rate, that is compared to the fuel and purchased power rate included in base rates. The difference in the two rates is recovered via Rider FAC to be billed to customers in the upcoming month. The Rider FAC could be positive or negative so that the sum of the fuel rate and purchased power rate recovered in base rates plus Rider FAC equals the actual cost of fuel and purchased power in that month. For example, in August, the Company will calculate the cost of fuel and purchased power attributable to serving retail load in the immediately prior month, July (called the Expense Month). The total cost is then divided by sales for the same July. The cost of fuel and purchased power for July is then compared to the fuel and purchased power rate included in base rates, with the difference being the Rider FAC rate that will be billed to customers in September (called the Revenue Month or the Billing Month). So, if the cost of fuel in July is $0.080 per kWh and $0.025 per kWh is being recovered in base rates, then the Rider FAC for September will be $0.055 per kWh.

Q. IS THERE A TRUE-UP PROVISION IN THE RIDER FAC CALCULATION?

A. Yes. Primarily due to monthly fluctuations in billed kWh sales and changes in actual fuel and purchased power costs, it is not common that the combination of Rider FAC and the base fuel rate exactly recovers the actual cost of fuel in a month. Consequently, there is a true-up provision whereby the Rider FAC rate is adjusted to ensure that the Company recovers no more and no less than its actual cost of providing electric generation service to its retail customers.

Q. DOES RIDER FAC CREATE VOLATILITY IN DUKE ENERGY KENTUCKY'S CUSTOMER RATES?

A. Yes. The combination of Duke Energy Kentucky's limited portfolio of generating assets and the monthly fluctuations in billed sales, creates an undesirable situation where the Rider FAC can change significantly from month-to-month. This coupled with recent market volatility in coal and power prices is leading to even more volatility in the monthly Rider FAC rate.

Q. EXPLAIN HOW THE GENERATION PORTFOLIO CONTRIBUTES TO THE VOLATILITY.

A. Duke Energy Kentucky is relatively small compared to other utilities and has only two major generating stations, East Bend and Woodsdale. East Bend is a roughly 600 MW single-unit coal-fired generating station available to the Company's retail customers. Woodsdale is a generating station made up of six roughly 80 MW combustion turbines that were designed to run only during peak times. The Woodsdale units normally rely on natural gas for generation but can run on fuel oil if natural gas supplies are constrained. The cost of fuel to generate energy at Woodsdale is typically much higher than the cost of fuel to generate energy at East Bend and, in most hours, is also higher than the cost of energy purchased from PJM's energy market.

Because of this limited resource mix, East Bend is the principal source of generation to serve the Company's retail customers, when it is available, and is supplemented mostly with energy purchased from PJM. The cost of purchasing energy from PJM can be quite volatile. Additionally, higher coal prices have and are expected to drive down the capacity factor of East Bend which lessens the value that the station provides to customers. Further, with less generation coming from Company resources, the remaining energy will come from greater market purchases. Even though historically the average cost of energy generated from East Bend was not particularly volatile, as coal prices increase, plants like East Bend will become more unfavorable in the competitive market contributing further to customer rate volatility. As a result of all of these factors, the average cost to serve retail customers in a given month can vary significantly.

Q. HOW DOES THE TIMING OF THE RIDER FAC CALCULATION IMPACT VOLATILITY?

A. As noted above, Rider FAC is calculated by dividing the total cost of fuel and purchased power to serve native load in the prior month by the billed sales for same prior month. Whatever rate is calculated for Rider FAC is billed in the ensuing month. Seasonal changes in demand means that retail load can vary significantly from month-to-month; so, recovering a rate calculated based on a shoulder month over a billing month during the summer can produce a significant over- or under-recovery of the FAC that will, in turn, influence the Rider FAC calculation in future months.

Q. IN YOUR OPINION, DO CUSTOMERS DESIRE VOLATILITY IN THEIR RETAIL RATES?

A. In my experience, I am not aware of any customer suggesting that volatility in their rates for electric service was a desirable feature of their utility bills. On the contrary, volatility in retail rates is more commonly the source of complaints from customers. So, to the extent that an opportunity exists to mitigate that volatility, it would be appreciated by many customers.

Q. WHAT IS THE COMPANY'S PROPOSAL TO MITIGATE VOLATILITY IN THE RIDER FAC RATE?

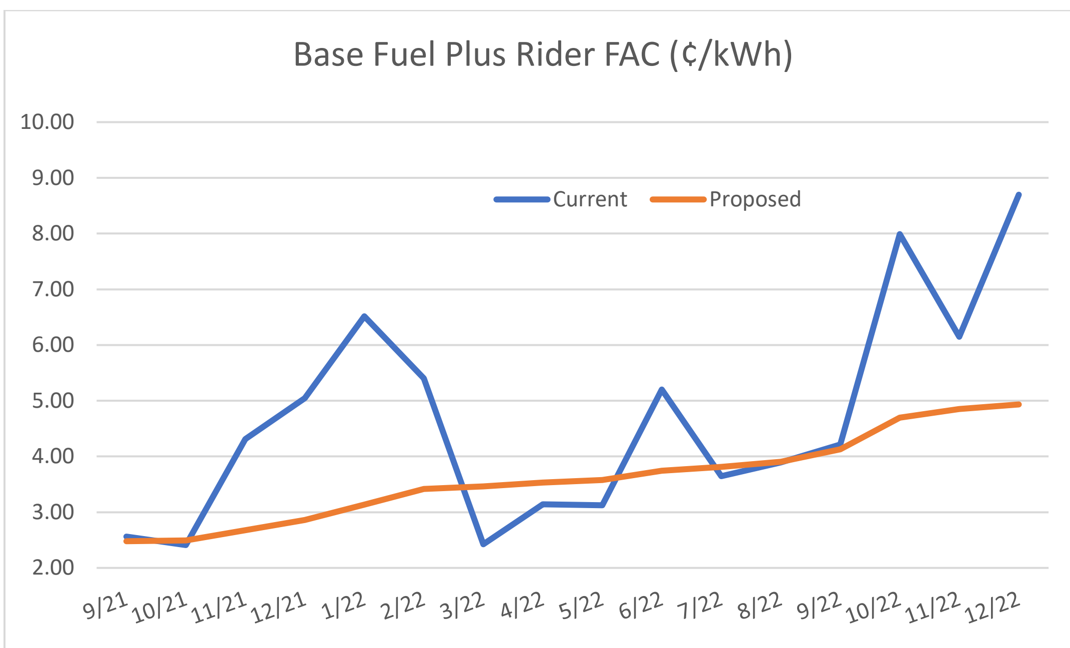
A. Duke Energy Kentucky proposes a very simple change to its Rider FAC calculation, which is to move from calculating the Rider FAC rate on a monthly basis to calculating the rate on a rolling twelve-month average basis. In Attachment SEL-1, I provide a revised set of schedules for Rider FAC reflecting the changes that would be necessary to make the calculation a rolling twelve-month average.

Q. DOES THE COMPANY REQUIRE ANY ADDITIONAL ACCOUNTING AUTHORITY FROM THE COMMISSION RELATED TO THIS PROPOSAL?

A. No. Although the use of a rolling twelve-month average may increase the magnitude of deferrals for over- or under-recovery of Rider FAC, the Company would continue the same deferral accounting for Rider FAC as is currently in effect.

Q. DO YOU HAVE AN ILLUSTRATION OF HOW THE COMPANY'S PROPOSAL WILL IMPACT VOLATILITY?

A. Simply reviewing recent Rider FAC filings provides an illustration of the how using a twelve-month rolling average to calculate Rider FAC smooths out the volatility currently evident in the monthly Rider FAC calculation.



As can be seen in this chart, the overall fuel rate (base fuel plus Rider FAC) when Rider FAC is calculated on a monthly basis can vary quite a bit. In this example, customer rates increased significantly from October 2021 to January 2022 by about 4 cents/kWh, which, for a typical residential customer using 1,000 kWh in a month, translates to a $40 swing in that customer's bill. And, in the same chart, the Rider FAC rate drops down by about 4 cents/kWh from January 2022 to March 2022; so, the customer saw another roughly $40 swing in the monthly bill. As shown by the chart, the Rider FAC continues to fluctuate monthly for the remaining months of 2022. If the Rider FAC had been calculated on a rolling twelve-month average, customers would have seen a steadier, more modest increase on their monthly bill due to fuel and purchased power costs and customers benefit from avoiding what can be unpleasant surprises in their monthly bills. Attachment SEL-2 contains the excel data used in creating the chart.

Q. WILL THIS CHANGE IMPACT THE COMMISSION'S CURRENT SIX-MONTH OR TWO-YEAR FAC REVIEW PROCESS?

A. No. The Commission will continue to have its existing authority and process to examine the Company's fuel procurement and FAC rate calculations.

Q. DOES THE COMPANY BENEFIT FROM THIS?

A. There would be no economic benefit to the Company from making this change. The only benefit to the Company would be from improving customer satisfaction and reducing customer complaints about volatility in its electric rates.

D. Generation Asset True-up Mechanism

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO CREATE A GENERATION ASSET TRUE-UP MECHANISM (RIDER GTM).

A. Duke Energy Kentucky is requesting approval of a placeholder rider, Rider GTM, as part of this proceeding to reconcile any remaining undepreciated plant balances following future retirements of its generating assets. As I've explained earlier in my testimony, the Company is proposing updates to its depreciation rates to align the depreciable lives with the service lives of the generation assets in order to minimize any intergenerational subsidization in cost recovery of these assets. The Company and its experts can estimate these depreciation rates so that the remaining net book value (less salvage) is as close to zero as possible at the end of their service lives, however, it is impossible to estimate this exactly and it is inevitable that there will be some remaining balance, positive or negative, that will need to be trued-up in customer rates. Creating this rider now provides a mechanism to ensure that customers pay no more or no less than the actual costs incurred by the Company for these assets. Rider GTM would act as either a credit or a charge to customers, depending upon the remaining net book value at the end of the asset's service life. Duke Energy Kentucky's proposed Rider GTM will be applicable to all electric customers.

Q. PLEASE EXPLAIN HOW THE COMPANY WILL CALCULATE THE REVENUE REQUIREMENT TO INCLUDE IN RIDER GTM.

A. The Company proposes to calculate a return on and of the remaining NBV of the generating assets and related assets at the time of retirement. The Company would calculate a revenue requirement to recover a return on the rate base associated with this remaining NBV along with recovery of the associated depreciation expense and any remaining required property tax expenses. Rate base would be calculated as gross plant in-service less accumulated depreciation less accumulated deferred income taxes associated with the plant in-service. Any unrecovered or over recovered cost of removal and other site-related assets would also be included in the net remaining plant in-service balance in the rider. The Company may also propose to recover necessary O&M expenses, if any, in Rider GTM. For example, if groundwater monitoring is required, the Company would propose to include those expenses in the rider.

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THE RETURN ON RATE BASE INCLUDED IN RIDER GTM?

A. The Company proposes to calculate the return on rate base at the weighted average cost of capital approved in the Company's most recent electric base rate case.

Q. WHY IS THIS APPROPRIATE?

A. The East Bend and Woodsdale generating stations have been included in rate base and the Company has been earning a return on this rate base since the time they were placed in service. In order for the Company to earn a return on the full value of the assets, the residual amounts that will be reflected in the regulatory asset should similarly earn a return.

Q. HAS THIS COMMISSION RECENTLY APPROVED SIMILAR MECHANISMS FOR ELECTRIC UTILITIES?

A. Yes. The Kentucky Power Company has the Decommissioning Rider (DR) authorized in Kentucky Public Service Case No. 2012-00578. Louisville Gas & Electric Company and Kentucky Utilities Company have the Retired Asset Recovery Rider (RAR) authorized in Kentucky Public Service Cases No. 2020-00349 and 2020-00350. Both DR and RAR function similarly to what the Company is proposing in Rider GTM, as they are mechanisms to recovery from retail ratepayers the retirement costs of generation. As in the proposed Rider GTM, riders DR and RAR recover a return on rate base included in the rider at the Company's WACC approved in its most recent rate case and serve to recover these retirement costs over a fixed period.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO IMPLEMENT RIDER GTM.

A. Upon approval of the tariff and mechanism in this proceeding, and in advance of the retirement date of either East Bend, Woodsdale, or both, Duke Energy Kentucky will file a separate application to set and implement Rider GTM. This application would be subject to Commission determination of reasonableness. Rider GTM charges or credits will not appear on a customer's bill until such applications are approved by the Commission. It would be the Company's intent to make such filings so that the first Rider GTM would appear in customer rates immediately after the assets were fully retired. The costs included in the rider would be recovered from customers over a ten-year period. Going forward, the Company will make annual applications with the Commission to update Rider GTM, reflecting any adjustments to the NBV of the assets or to any other data inputs of the rider calculation as necessary. The revenue requirement would then be allocated to customer classes consistent with the cost of service study approved in the Company's most recent electric base rate case.

Q. HOW WILL CUSTOMERS BE CHARGED OR CREDITED UNDER THIS MECHANISM?

A. All customer classes would be charged or credited as a percentage of base revenues. For residential customers, base revenues would include fuel charges. For non-residential customers, base revenues would exclude fuel charges.

Q. IS THE COMPANY REQUESTING ANY ACCOUNTING TREATMENT RELATED TO RIDER GTM?

A. Yes. Upon retirement of either East Bend, Woodsdale, or both, the Company is requesting the authority to establish a regulatory asset to record any remaining net book value associated with these assets. Once Rider GTM is approved and in customer rates, the Company would begin amortizing this regulatory asset appropriately. Company witness Ms. Weatherston discusses this accounting further in her testimony.

E. Incremental Local Investment Charge Mechanism

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSAL TO CREATE AN INCREMENTAL LOCAL INVESTMENT CHARGE MECHANISM.

A. Duke Energy Kentucky is proposing updates to the Company's Local Government Fee Tariff as explained by Company witnesses Ms. Spiller and Mr. Sailers. Additionally, the Company is proposing a new Incremental Local Investment Charge (Rider ILIC) to recover the costs of incremental processes and system investments required pursuant to a local ordinance or franchise, such as undergrounding of electric facilities or other relocations or system improvements and upgrades that are either requested or required by local regulation that are outside the Company's regular system-wide construction plans. This rider is necessary to ensure appropriate cost recovery from customers if a city passes an ordinance that imposes such incremental processes and associated costs upon the utility specific to that city, which are outside the normal system needs of the Company.

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE CHARGES FOR INCREMENTAL LOCAL INVESTMENT?

A. Mr. Sailers explains in his testimony that the charges will be determined through application of a levelized fixed charge rate.

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO IMPLEMENT RIDER ILIC.

A. Upon approval of the tariff and mechanism in this proceeding, Duke Energy Kentucky will file a separate application to implement Rider ILIC as necessary in response to a local government mandate such as an ordinance or franchise. This application would be filed prior to the Company commencing work on the mandated project and subject to Commission determination of reasonableness. Rider ILIC charges will not appear on a customer's bill until such applications are approved by the Commission. Going forward, the Company will make annual applications with the Commission to update Rider ILIC, reflecting any new proposed capital projects and the depreciation of previously approved capital projects as well as any other necessary data input changes supporting the rider calculation.

Q. HOW WILL THE REVENUE REQUIREMENT INCLUDED IN RIDER ILIC BE ALLOCATED TO CUSTOMERS?

A. The Company is proposing that the Commission shall determine whether such a charge shall be included on all customer bills or only on those customers within the boundaries of the Public Authority imposing such costs. The mechanism and process proposed by the Company is intended to allow the Company to recover its costs of complying with these ordinances, bringing them to the Commission to determine how the costs of such ordinances should be addressed. Having this mechanism and process in place will assist the Company by making it clear that the cost recovery of these incremental locally imposed costs will be determined by the Commission and may be recovered locally.

Q. HOW WILL CUSTOMERS BE CHARGED UNDER THIS MECHANISM?

A. The Company will charge customers as determined by the Commission.

IV. REASONABLENESS OF REQUEST

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

A. Yes. Duke Energy Kentucky has done a good job of keeping its expenses reasonable over the years; however, the need to continually invest it its electric generation, transmission and distribution system creates a need for the Company to seek additional rate relief. The need to update the depreciation rates such that the depreciable lives align with the service lives of assets is also imperative so that cross-generation subsidization does not occur, and future rate payers are not left with the burden of paying twice: once for significant amounts of post-retirement undepreciated plant remaining after the generating assets' retirements, and twice for their replacement resource(s).

The approval of Rider GTM will allow the Company to true-up and recover any remaining undepreciated plant balances that remain at the end of their useful lives and will ensure that customers pay no more or no less than the actual costs incurred. The approval of the Company's new EV Programs and CEC Program is reasonable as they are enabling the Company to provide assistance to customers who are interested in electric vehicle and solar infrastructure. The changes to the Company's Rider FAC are also reasonable to help stabilize and smooth out customers' monthly bills that are currently subject to extreme volatility. The approval of the Company's new mechanism to address cost recovery for prudently incurred costs the Company is required to make resulting from governmental mandates as a result of local legislative ordinances such as franchises or other means is reasonable to ensure the Company can recover these prudently incurred investments from the appropriate customers.

V. FILING REQUIREMENTS SPONSORED BY WITNESS

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

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

Q. PLEASE DESCRIBE FR 16(9).

A. FR 16(9) is Duke Energy Kentucky's acknowledgement that it understands that its application will not be accepted for filing until it has cured any deficiencies as determined by the Commission.

VI. CONCLUSION

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

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

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

A. Yes.

Q. WERE ATTACHMENTS SEL-1, SEL-2, FR 16(1)(b)(1) AND FR 16(9) PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Sarah E. Lawler, VP Rates & Regulatory Strategy OH/KY, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Sarah E. Lawler Affiant

Subscribed and sworn to before me by Sarah E. Lawler on this 30th day of November, 2022.

NOTARY PUBLIC

My Commission Expires: July 8, 2027

NOTARY PUBLIC STATE OF OHIO

EMILIE SUNDERMAN
Notary Public
State of Ohio
My Comm. Expires
July 8, 2027

Schedule 1

DUKE ENERGY KENTUCKY
FUEL ADJUSTMENT CLAUSE SCHEDULE

Twelve Month Average - Expense Month: **July 20XX**

Line No.	Description		Amount	Rate ($/kWh)
1	Fuel F_m (Schedule 2, Line K)		$ -	
2	Sales S_m (Schedule 3, Line C)	÷	-	-
3	Base Fuel Rate (F_b/S_b) per PSC Order in Case No. 2021-00057		(-)	-
4	Fuel Adjustment Clause Rate (Line 2 - Line 3)			-

Effective Date for Billing: ____________________

Submitted by: ____________________

Title: ____________________

Date Submitted: ____________________

Schedule 2

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Twelve Month Average - Expense Month: July 20XX

		Dollars ($)	
A. Company Generation			
Coal Burned	(+)	$ -	
Oil Burned	(+)	-	
Gas Burned	(+)	-	
Net Fuel Related RTO Billing Line Items	(-)	-	
Fuel (assigned cost during Forced Outage[a])	(+)	-	
Fuel (substitute cost during Forced Outage[a])	(-)	-	
Sub-Total		$ -	
B. Purchases			
Economy Purchases	(+)	$ -	
Other Purchases	(+)	-	
Other Purchases (substitute for Forced Outage[a])	(-)	-	
Less purchases above highest cost units	(-)	-	
Sub-Total		$ -	
C. Non-Native Sales Fuel Costs	(-)	$ -	
D. Total Fuel Costs (A + B - C)	(+)	$ -	(b)
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ -	
F. Adjustment indicating the difference in actual fuel cost for the month of June 20XX and the estimated cost orginally reported $x,xxx,xxx (actual) - $x,xxx,xxx (estimate)	(+)	$ -	
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ -	
H. Prior Period Correction	(+)	$ -	
I. Deferral of Current Purchased Power Costs	(-)	$ -	
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ -	

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Estimated - to be trued up in the filing next month

Schedule 3

DUKE ENERGY KENTUCKY
SALES SCHEDULE

Twelve Month Average - Expense Month: July 20XX

		Kilowatt-Hours Current Month
A. Generation (Net)	(+)	-
Purchases Including Interchange-In	(+)	-
Sub-Total		-
B. Pumped Storage Energy	(+)	-
Non-Native Sales Including Interchange Out	(+)	-
System Losses [a]	(+)	-
Sub-Total		-
C. Total Sales (A - B)		-

Note: [a] Average of prior 12 months.

Schedule 4

DUKE ENERGY KENTUCKY
FINAL FUEL COST SCHEDULE

Twelve Month Average - Expense Month: June 20XX

			Dollars ($)
A. Company Generation			
Coal Burned	(+)	$	-
Oil Burned	(+)		-
Gas Burned	(+)		-
Net Fuel Related RTO Billing Line Items	(-)		-
Fuel (assigned cost during Forced Outage[a])	(+)		-
Fuel (substitute cost during Forced Outage[a])	(-)		-
Sub-Total		$	-
B. Purchases			
Economy Purchases	(+)	$	-
Other Purchases	(+)		-
Other Purchases (substitute for Forced Outage[a])	(-)		-
Less purchases above highest cost units	(-)		-
Sub-Total		$	-
C. Non-Native Sales Fuel Costs	(-)	$	-
D. Total Fuel Costs (A + B - C)		$	-

Note: [a] Forced Outage as defined in 807 KAR 5:056.

Schedule 5

DUKE ENERGY KENTUCKY
OVER OR (UNDER) RECOVERY SCHEDULE

Twelve Month Average Expense Month:
May 20XX

Line No.	Description			
1	FAC Rate Billed ($/kWh)	(+)		0.000000
2	Retail kWh Billed at Above Rate	(x)		-
3	FAC Revenue/(Refund) (Line 1 * Line 2)		$	-
4	kWh Used to Determine Last FAC Rate Billed	(+)		-
5	Non-Jurisdictional kWh included in Line 4	(-)		-
6	Kentucky Jurisdictional kWh Included in Line 4 (Line 4 - Line 5)			-
7	Recoverable FAC Revenue/(Refund) (Line 1 * Line 6)		$	-
8	Over or (Under) (Line 3 - Line 7)		$	-
9	Total Sales (Schedule 3, Line C)	(-)		-
10	Kentucky Jurisdictional Sales	(÷)		-
11	Ratio of Total Sales to KY Jursidictional Sales (Line 9 ÷ Line 10)			-
12	Total Company Over or (Under) Recovery (Line 8 * Line 11)	(+)	$	-
13	Amount Over or (Under) Recovered in prior filings	(-)	$	-
14	Total Company Over or (Under) Recovery		$	-

Schedule 6

DUKE ENERGY KENTUCKY
REGIONAL TRANSMISSION ORGANIZATION RESETTLEMENTS
FUEL COST SCHEDULE

Twelve Month Average - Expense Month: March 20XX

		Dollars ($)
A. Company Generation		
Coal Burned	(+)	$ -
Oil Burned	(+)	-
Gas Burned	(+)	-
Net Fuel Related RTO Billing Line Items	(-)	-
Fuel (assigned cost during Forced Outage[a])	(+)	-
Fuel (substitute cost during Forced Outage[a])	(-)	-
Sub-Total		$ -
B. Purchases		
Economy Purchases	(+)	$ -
Other Purchases	(+)	-
Other Purchases (substitute for Forced Outage[a])	(-)	-
Less purchases above highest cost units	(-)	-
Sub-Total		$ -
C. Non-Native Sales Fuel Costs	(-)	$ -
D. Total Fuel Costs (A + B - C)		$ -
E. Total Fuel Costs Previously Reported	(-)	$ -
F. Prior Period Adjustment	(+)	$ -
G. Adjustment due to PJM Resettlements		$ -

Note: [a] Forced Outage as defined in 807 KAR 5:056.

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

		2020	2020	2020	2020	2020	2021	2021	2021	2021
Expense Month		August	September	October	November	December	January	February	March	April
Revenue Month		October	November	December	January	February	March	April	May	June
		Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)	Dollars ($)
A. Company Generation										
Coal Burned	(+)	7,864,884.61	3,688,943.92	0.00	1,617,603.73	7,791,501.66	5,716,137.13	7,516,245.87	6,489,964.36	5,331,139.86
Oil Burned	(+)	83,127.74	77,029.31	68,951.58	157,233.99	163,530.72	378,940.63	513,291.64	118,040.26	94,300.56
Gas Burned	(+)	343,250.35	67,819.00	342,000.00	(956.45)	346,650.00	45,350.00	440,235.33	(21,000.00)	84,650.00
Net Fuel Related RTO Billing Line Items	(-)	(234,685.29)	(140,365.92)	288,850.86	45,417.10	(137,097.87)	(300,867.25)	(511,820.94)	(1,370,851.65)	(469,183.22)
Fuel (assigned cost during Forced Outage[a])	(+)	0.00	0.00	0.00	0.00	0.00	738,976.60	0.00	31,777.40	203,939.79
Fuel (substitute cost during Forced Outage[a])	(-)	0.00	0.00	0.00	0.00	0.00	21,305.40	0.00	8,039.57	60,250.85
Sub-Total		8,525,947.99	3,974,158.15	122,100.72	1,728,464.17	8,438,780.25	7,158,966.21	8,981,593.78	7,981,594.10	6,122,962.58
B. Purchases										
Economy Purchases	(+)	773,507.13	2,891,823.73	7,478,132.08	5,415,654.53	457,932.90	3,196,436.58	416,801.81	659,771.94	2,395,449.78
Other Purchases	(+)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	0.00	0.00	0.00	0.00	0.00	1,057,570.33	0.00	37,694.70	295,541.22
Less purchases above highest cost units	(-)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		773,507.13	2,891,823.73	7,478,132.08	5,415,654.53	457,932.90	2,138,866.25	416,801.81	622,077.24	2,099,908.56
C. Non-Native Sales Fuel Costs		564,764.84	162,965.50	1,163.33	117,760.57	1,501,374.59	948,095.94	1,237,838.66	723,810.19	1,114,892.90
D. Total Fuel Costs (A + B - C - D)		$8,734,690.28	$6,703,016.38	$7,599,069.47	$7,026,358.13	$7,395,338.56	$8,349,736.52	$8,160,556.93	$7,879,861.15	$7,107,978.24
E. Total Company Over/(Under) Recovery from Sch 5, Line 14	(-)	$ (143,519.90)	$ (82,946.29)	$ (33,095.72)	$ 75,005.74	$ 203,023.98	$ 137,344.72	$ (10,654.03)	$ 302.89	$ (59,311.18)
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ (152,197.81)	$ (43,558.76)	$ (41,489.53)	$ (31,752.37)	$ 389,335.17	$ (15,663.35)	$ 52,906.32	$ (112,254.79)	$ (7,702.08)
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ 187,005.15	$ 594.89	$ (43,034.84)	$ (48,202.42)	$ (44,566.81)	$ (21,140.71)	$ 7,280.37	$ 45,529.26	$ (13,611.86)
H. Prior Period Correction	(+)	$ -	$ -	$ (13,380.00)	$ -	$ -	$ -	$ -	$ -	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$8,913,017.52	$6,742,998.80	$7,534,260.82	$6,871,397.60	$7,537,082.94	$8,175,587.74	$8,231,397.65	$7,812,832.73	$7,145,975.48
Estimated Sales (Schedule 3, Line C)		368,266,169	312,223,321	276,561,171	271,235,251	331,139,835	345,771,012	329,316,865	302,826,675	276,949,391
Caclulated Fuel Rate		0.024203	0.021597	0.027243	0.025334	0.022761	0.023645	0.024995	0.0258	0.025802
Base Fuel Rate		0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837
Monthly FAC Rate		0.000366	(0.002240)	0.003406	0.001497	(0.001076)	(0.000192)	0.001158	0.001963	0.001965

12 Month Rolling Average Fuel Cost
12 Month Rolling Average Sales
12 Month Rolling Average Calculated Fuel Rate
Base Fuel Rate
12 Month Rolling Average FAC Rate

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

		2021	2021	2021	2021	2021	2021	2021	2021	2022
Expense Month		**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**January**
Revenue Month		**July**	**August**	**September**	**October**	**November**	**December**	**January**	**February**	**March**
		Dollars ($)	**Dollars ($)**	**Dollars ($)**	**Dollars ($)**	**Dollars ($)**	**Dollars ($)**	**Dollars ($)**	**Dollars ($)**	**Dollars ($)**
A. Company Generation										
Coal Burned	(+)	5,488,967.75	7,332,974.66	6,938,910.36	6,113,636.83	842,768.46	(326,122.68)	0.00	1,055,995.53	7,476,853.43
Oil Burned	(+)	199,289.49	208,007.20	172,053.68	125,805.03	176,644.74	0.00	89,049.95	454,576.85	569,348.65
Gas Burned	(+)	550,950.00	327,419.60	386,994.80	788,510.00	148,800.00	291,600.00	530,302.80	(12,741.40)	1,066,985.31
Net Fuel Related RTO Billing Line Items	(-)	(359,816.86)	(123,940.46)	2,215.60	(191,247.65)	(117,892.39)	28,022.26	296,817.97	(238,885.63)	(561,337.63)
Fuel (assigned cost during Forced Outage[a])	(+)	0.00	46,770.49	523,738.44	1,819,003.00	1,065,236.21	0.00	0.00	122,041.50	11,428.41
Fuel (substitute cost during Forced Outage[a])	(-)	0.00	0.00	79,535.91	0.00	5,831.76	0.00	0.00	0.00	0.00
Sub-Total		6,599,024.10	8,039,112.41	7,939,945.77	9,038,202.51	2,345,510.04	(62,544.94)	322,534.78	1,858,758.11	9,685,953.43
B. Purchases										
Economy Purchases	(+)	2,829,001.52	1,005,228.79	3,576,247.61	5,154,741.36	13,971,151.97	15,299,896.68	18,419,366.54	16,526,604.64	2,720,331.75
Other Purchases	(+)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[a])	(-)	0.00	91,953.92	988,651.04	3,561,396.39	1,791,455.04	0.00	0.00	185,208.96	27,973.93
Less purchases above highest cost units	(-)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Sub-Total		2,829,001.52	913,274.87	2,587,596.57	1,593,344.97	12,179,696.93	15,299,896.68	18,419,366.54	16,341,395.68	2,692,357.82
C. Non-Native Sales Fuel Costs		1,135,663.66	572,429.64	264,114.29	539,710.96	92,091.35	(30,407.30)	0.00	70,092.95	1,171,055.69
D. Total Fuel Costs (A + B - C - D)		$8,292,361.96	$8,379,957.64	$10,263,428.05	$10,091,836.52	$14,433,115.62	$15,267,759.04	$18,741,901.32	$18,130,060.84	$11,207,255.56
E. Total Company Over/(Under) Recovery from Sch 5, Line 14	(-)	$ (55,952.02)	$ 100,718.49	$ 222,056.83	$ (8,368.81)	$ (128,859.12)	$ 125,425.47	$ (897,363.50)	$ 844,247.06	$ 2,042,481.82
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ (28,766.59)	$ (51,545.97)	$ (117,738.72)	$ (414,562.63)	$ (271,428.42)	$ (59,067.07)	$ 13,390.40	$ (49,077.19)	$ 14,363.31
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (42,866.63)	$ 44,815.94	$ 42,608.37	$ (37,769.12)	$ (55,246.37)	$ (73,698.43)	$ (118,890.58)	$ (9,788.38)	$ (77,473.80)
H. Prior Period Correction	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ (11.01)	$ -	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$8,276,680.76	$8,272,509.12	$9,966,240.87	$9,647,873.58	$14,235,299.95	$15,009,568.07	$19,533,753.63	$17,226,948.21	$9,101,663.25
Estimated Sales (Schedule 3, Line C)		305,405,220	359,198,707	389,302,229	400,337,761	330,017,940	297,401,448	299,893,968	319,017,287	375,886,048
Caclulated Fuel Rate		0.027101	0.02303	0.0256	0.024099	0.043135	0.050469	0.065136	0.054	0.024214
Base Fuel Rate		0.023837	0.023837	0.023837	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401
Monthly FAC Rate		0.003264	(0.000807)	0.001763	(0.001302)	0.017734	0.025068	0.039735	0.028599	(0.001187)
12 Month Rolling Average Fuel Cost				$7,956,665	$8,017,903	$8,642,262	$9,265,204	$10,320,400	$11,127,889	$11,205,062
12 Month Rolling Average Sales				322,349,654	325,022,287	326,505,171	328,241,861	330,630,088	329,619,875	332,129,462
12 Month Rolling Average Calculated Fuel Rate				0.024683	0.024669	0.026469	0.028227	0.031214	0.033760	0.033737
Base Fuel Rate				0.023837	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401
12 Month Rolling Average FAC Rate				0.000846	(0.000732)	0.001068	0.002826	0.005813	0.008359	0.008336

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Expense Month / Revenue Month		2022 February April Dollars ($)	2022 March May Dollars ($)	2022 April June Dollars ($)	2022 May July Dollars ($)	2022 June August Dollars ($)	2022 July September Dollars ($)	2022 August October Dollars ($)	2022 September November Dollars ($)	2022 October December Dollars ($)
A. Company Generation										
Coal Burned	(+)	6,414,479.92	6,885,984.52	4,444,351.74	6,032,691.22	8,522,735.43	7,226,973.11	3,207,070.88	5,261,728.21	0.00
Oil Burned	(+)	371,895.47	154,732.62	184,625.12	584,268.14	242,396.51	128,605.31	363,894.41	467,406.17	105,516.98
Gas Burned	(+)	25,500.00	312,250.00	290,094.55	218.50	893,000.00	2,102,900.00	1,206,684.00	214,650.00	427,850.00
Net Fuel Related RTO Billing Line Items	(-)	(518,361.48)	(26,527.61)	(303,464.28)	(732,229.26)	709,395.33	234,769.08	(51,230.70)	(259,203.65)	784,636.04
Fuel (assigned cost during Forced Outage[(a)])	(+)	269,854.13	0.00	0.00	632,122.62	375,626.32	469,296.58	324,894.14	41,348.89	0.00
Fuel (substitute cost during Forced Outage[(a)])	(-)	0.00	0.00	0.00	0.00	0.00	396,717.32	56,047.55	0.00	0.00
Sub-Total		7,600,091.00	7,379,494.75	5,222,535.69	7,981,529.74	9,324,362.93	9,296,288.60	5,097,726.58	6,244,336.92	(251,269.06)
B. Purchases										
Economy Purchases	(+)	4,082,871.30	3,033,678.85	9,487,445.85	6,343,954.70	4,706,418.95	12,169,879.82	28,551,397.54	14,240,152.39	17,284,488.91
Other Purchases	(+)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Purchases (substitute for Forced Outage[(a)])	(-)	656,553.22	0.00	0.00	1,976,659.13	1,212,552.28	1,484,515.40	1,190,624.11	127,489.35	0.00
Less purchases above highest cost units	(-)	0.00	0.00	0.00	0.00	6,336.76	0.00	0.00	0.00	0.00
Sub-Total		3,426,318.08	3,033,678.85	9,487,445.85	4,367,295.57	3,487,529.91	10,685,364.42	27,360,773.43	14,112,663.04	17,284,488.91
C. Non-Native Sales Fuel Costs		388,747.71	539,491.12	514,797.97	779,258.14	821,504.20	558,011.84	304,808.60	237,388.90	84,081.27
D. Total Fuel Costs (A + B - C - D)		$10,637,661.37	$9,873,682.48	$14,195,183.57	$11,569,567.17	$11,990,388.64	$19,423,641.18	$32,153,691.41	$20,119,611.06	$16,949,138.58
E. Total Company Over/(Under) Recovery from Sch 5, Line 14	(-)	$ 825,421.36	$ 141,865.08	$ (738,997.71)	$ (222,697.58)	$ (1,775,863.94)	$ 3,274,310.65	$ 845,983.16	$ (99,343.45)	$ (6,764,914.88)
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ 206,368.28	$ 128,594.31	$ (21,864.41)	$ 61,859.96	$ 346,509.31	$ (98,987.91)	$ (543,277.66)	$ (382,864.75)	$ (13,129.38)
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (119,883.29)	$ (120,893.82)	$ (62,297.91)	$ (204,518.81)	$ (52,205.92)	$ 450,908.22	$ (87,267.29)	$ (92,837.37)	$ (580,090.11)
H. Prior Period Correction	(+)	$ 56,990.04	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$9,955,715.04	$9,739,517.89	$14,850,018.96	$11,649,605.90	$14,060,555.97	$16,501,250.84	$30,677,163.31	$19,743,252.39	$23,120,833.97
Estimated Sales (Schedule 3, Line C)		317,173,784	311,837,927	285,387,492	319,688,693	361,106,224	391,323,738	383,918,237	321,177,184	265,818,130
Caclulated Fuel Rate		0.031389	0.031233	0.052035	0.03644	0.038937	0.042168	0.079905	0.061472	0.08698
Base Fuel Rate		0.025401	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401
Monthly FAC Rate		0.005988	0.005832	0.026634	0.011039	0.013536	0.016767	0.054504	0.036071	0.061579
12 Month Rolling Average Fuel Cost		$11,348,755	$11,509,312	$12,151,316	$12,432,393	$12,914,730	$13,459,314	$15,211,755	$15,670,751	$16,346,690
12 Month Rolling Average Sales		331,117,538	331,868,476	332,571,651	333,761,940	333,920,900	334,089,359	332,721,066	331,984,336	329,352,393
12 Month Rolling Average Calculated Fuel Rate		0.034274	0.034680	0.036537	0.037249	0.038676	0.040287	0.045719	0.047203	0.049633
Base Fuel Rate		0.025401	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401	0.025401
12 Month Rolling Average FAC Rate		0.008873	0.009279	0.011136	0.011848	0.013275	0.014886	0.020318	0.021802	0.024232

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

WILLIAM LUKE

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is William Luke and my business address is 1000 East Main Street, Plainfield, IN 46168.

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

A. I am Vice President Midwest Generation for Duke Energy Business Services, LLC (DEBS). DEBS is a service company subsidiary of Duke Energy Corporation (Duke Energy), which provides services to Duke Energy and its subsidiaries, including Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUNDS.

A. I have a Bachelor of Engineering degree from State University of New York Maritime College and received a Merchant Marine License from the U.S. Coast Guard. I began my career as a licensed maritime engineer and worked for the New York Power Authority and the Brooklyn Navy Yard Cogeneration facility. I have more than 30 years of power generation experience including various leadership roles in operations, strategy, maintenance, startup and commissioning. I joined the Company in 2005 as a production manager at the Hines Energy Complex in Florida and later managed Duke Energy's Anclote, Bartow, Suncoast and Cayuga stations. Next, I became the director of Midwest Environmental Field Support and then General Manager of Regional Services in the Midwest. I assumed my current role in April 2022.

Q. PLEASE SUMMARIZE YOUR DUTIES AS VICE PRESIDENT MIDWEST GENERATION.

A. In this role, I am responsible for providing safe, compliant, and reliable operation of Duke Energy's Midwest generation fleet (Kentucky and Indiana), which includes four coal, one combined cycle, one hydro, six simple cycle combustion turbine, three solar, and one combined heat and power site. Combined, these assets provide approximately 7,400 MWs of generation. My primary responsibilities include managing the fleet within design parameters and implementing work practices and procedures that ensure safe and regulatorily compliant operation and maintenance activities.

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

A. No, I have not.

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

A. I describe the Company's two generating stations, East Bend Generating Station (East Bend) and Woodsdale Combustion Turbines (Woodsdale) (collectively the Plants). I explain how these Plants are used to provide safe, affordable, reliable, and reasonable electric service to Duke Energy Kentucky's customers and the Company's continued investment in these stations. I give an update on the decommissioning of the Miami Fort 6 unit. I also discuss the three solar stations owned by Duke Energy Kentucky. I discuss the new anticipated retirement date of East Bend and Woodsdale and the drivers for those anticipated retirements.

Finally, I sponsor part of the information in the capital budget relating to the Plants contained in Filing Requirements (FR) 16(7)(b), FR 16(7)(f) and FR 16(7)(g), which I provided to Duke Energy Kentucky witness Mr. Carpenter for the forecasted financial data.

II. GENERAL DESCRIPTION OF DUKE ENERGY KENTUCKY'S GENERATING STATIONS

A. EAST BEND

Q. PLEASE DESCRIBE EAST BEND.

A. East Bend is a 600 megawatt (MW) (net summer rating) coal-fired steam unit located along the Ohio River in Boone County, Kentucky which was commissioned in 1981. The net ratings represent the net amount of power that we can dispatch from the plants after some portion of the gross power output is used to power the plant machinery. East Bend was originally planned for up to four coal-fired units but only one unit (Unit 2) was constructed. The station has river facilities to allow barge deliveries of coal and lime. East Bend is designed to burn eastern bituminous coal and achieved a net plant heat rate of 11,010 Btu/kWh for calendar year 2021. The major pollution control features are a high-efficiency hot side electrostatic precipitator, a selective catalytic reduction control (SCR) system designed to reduce nitrogen oxide (NO_x) emissions by 85 percent, and a FGD system designed to remove sulfur dioxide (SO_2) emissions to an average of 97 percent. The station's electrical output is directly connected to the Duke Energy Midwest (consisting of Kentucky and Ohio) 345 kilovolt (kV) transmission system.

Q. PLEASE DESCRIBE WHAT ACTIONS THE COMPANY IS CURRENTLY DOING TO MAINTAIN RELIABILITY AT EAST BEND.

A. Although East Bend is approaching the end of its service life and the Company plans to replace the asset with other resources, it is important to keep the remaining unit in efficient working order to support the energy needs of our customers. Therefore, costs for this asset will continue to be incurred and investments made as appropriate and prudent to ensure that the same reliable cost effective electricity that customers have counted on for decades remains available while the replacement of those units is developed and implemented.

Duke Energy Kentucky follows regular maintenance schedules at its plants. Generally speaking, the stations have periodic maintenance activities scheduled during off-peak seasons in the spring and/or fall. Typically, outage duration can range from 1 to 12 weeks depending on project scope. Outage and project scopes are determined utilizing various sources and techniques such as condition assessments, operational data, and Original Equipment Manufacturer (OEM) recommendations.

Q. PLEASE BRIEFLY DESCRIBE DUKE ENERGY KENTUCKY'S RECENT CAPITAL INVESTMENTS IN EAST BEND THAT ALLOW IT TO CONTINUE TO OPERATE SAFELY, EFFICIENTLY, AND IN COMPLIANCE WITH ENVIRONMENTAL REQUIREMENTS FOR THE BENEFIT OF CUSTOMERS.

A. In the spring of 2021, the Company performed an 8 week outage at East Bend to perform significant maintenance to the station's turbine, generator, boiler, and FGD. The major scope of work associated with the East Bend 2021 Outage included a complete rewind of the Generator Stator, significant maintenance of boiler fuel, steam, and water components, main low-pressure turbine blade evaluation, and FGD absorber module inlet nozzle refurbishment.

In the fall of 2022, the Company conducted a 5 week outage at East Bend to perform significant maintenance to the station's boiler, FGD and coal handling equipment. The major scope of work associated with the East Bend 2022 Fall Outage includes a complete replacement of secondary air heater baskets, a pulverizer overhaul, a primary air fan bearing upgrade, FGD module cleaning and maintenance of the coal barge unloader. This scope of work is part of the reliability plan to sustain reliability and long-term operation.

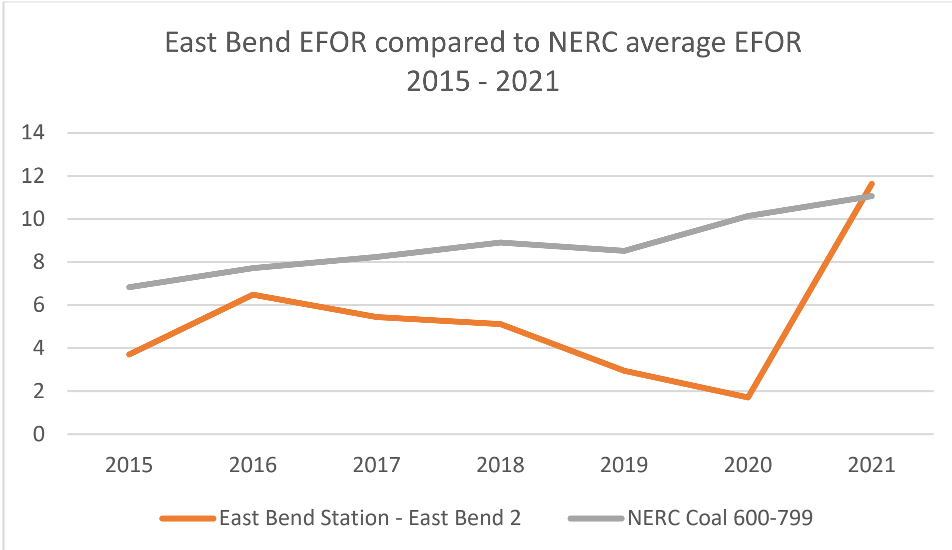
The Company has made other capital investments as necessary outside of these outages to ensure the reliability of the plant. Since the time of the Company's last rate case, investments have been made for a precipitator rebuild, construction of a lime injection system, a generator stator rewind, SCR catalyst replacements and a superheater outlet header replacement. All of the capital additions to East Bend including those listed above, are necessary to ensure the reliability of the station.

East Bend's ash basin excavation completed in July 2019. The East landfill is nearing capacity fill, and plans are underway to cap the final cells of the landfill as was authorized by the Commission in Case No. 2021-00290. The West landfill cells 1 and 2 are in current use, and planning is beginning for cell 3, which is anticipated to commence construction in 2026.

Q. IS EAST BEND USED AND USEFUL FOR SERVING DUKE ENERGY KENTUCKY'S NATIVE LOAD CUSTOMERS?

A. Yes. East Bend, as described above, is a high quality generating asset relative to the age and condition of comparable generating plants. One useful measure of the performance of a coal-fired generating station is the Equivalent Forced Outage Rate (EFOR), which is equal to the hours of unit forced unavailability (unplanned outage hours and equivalent unplanned derated hours) given as a percentage of the total hours of service plus the unavailability of that unit (unplanned outage, unplanned derate, and service hours). For example, if PJM Interconnection LLC (PJM) anticipated a unit to run 1,000 hours in a certain year but the unit was unable to run 100 of those hours due to unexpected problems, the unit's EFOR would be 10%. A low EFOR number is desirable.

The chart below provides a summary of East Bend's EFOR and compares it to the EFOR reported for North American Electric Reliability Corporation (NERC) coal-fired units over the same period.



As shown in the chart above, East Bend has outperformed the NERC average EFOR for units of similar size in six of the past seven years. The higher EFOR in 2021 was due to a generator excitation issue. Generator excitation means as the load on the generator is increased, an increase in current flow causes the voltage to drop. The excitation system senses this decrease in voltage and increases the strength of the magnetic field to return the voltage to the desired level. This issue was resolved and the unit was returned to service with no other impacts to generation. The 2022 year to date EFOR for East Bend through October is 4.42.

B. <u>WOODSDALE</u>

Q. PLEASE DESCRIBE WOODSDALE.

A. Woodsdale is a six-unit, simple cycle, combustion turbine (CT) station located in Butler County, Ohio, just north of Cincinnati, with a collective net winter rating of 564 MW and a net summer rating of 476 MW. Woodsdale was designed to provide peaking service and to have black start and dual fuel capability. Black start capability means that the station has the ability to initiate a recovery of a substantial portion of load without relying on energy from outside sources if the regional grid experiences a blackout. The black start capability is initiated by an Allison 501-KB gas turbine that serves as a back-up power source and allows the station to start generating energy without power from the electric grid. Historically, the dual fuel capability was provided through the ability to burn both natural gas and propane. The propane dual fuel service is provided through a backup ultra-low sulfur diesel fuel (ULSD) system commissioned in May 2019.

Woodsdale is connected to the Texas Eastern Transmission Company (TETCO) interstate pipeline that transports natural gas to supply the station. The design of Woodsdale as a peaking unit with low capacity factors does not support acquiring firm natural gas transportation through the available natural gas interstate pipelines.

Q. PLEASE EXPLAIN WHY WOODSDALE BEING DESIGNED FOR PEAKING CAPABILITY IS SIGNIFICANT.

A. By design, peaking units run infrequently for short periods to meet peak demand. As a result, peaking units have a much lower capacity factor than baseload units or intermediate load units. Woodsdale, like most natural gas CTs are generally dispatched in response to market price signals. These units have great flexibility in terms of operation and can start, ramp up and down quickly in response to changes in the energy markets and reliability. Consequently, their higher production cost versus a base load coal station like East Bend or an intermediate combined cycle generating station makes Woodsdale (and all peaking units) fall lower on the list in terms of resource dispatch stacking.

Q. PLEASE DESCRIBE WHAT ACTIONS THE COMPANY IS CURRENTLY DOING TO MAINTAIN OR ENHANCE RELIABILITY AT WOODSDALE.

A. Duke Energy Kentucky follows similar periodic maintenance cycles for the Woodsdale units to those of East Bend that I mentioned above. The dual fuel capabilities installed in 2019 provide another option for safe, reliable power from the Woodsdale facility. Since the time of the Company's last rate case, the Company has also made necessary investments to ensure the reliability of the plant some of which include generator field rewinds, a turbine section replacement, and a generator rotor rewind.

C. <u>SOLAR FACILITIES</u>

Q PLEASE DESCRIBE THE SOLAR FACILITIES OWNED BY DUKE ENERGY KENTUCKY.

A. Duke Energy Kentucky owns three solar facilities: Walton 1 Solar Plant located in Walton, KY.; Walton 2 Solar Plant, also located in Walton, KY: and Crittenden Solar Plant, located in Dry Ridge, KY. These three plants combined provide 2.8 MW of firm summer capacity. All three sites have commercial operation dates of December 14, 2017.

D. MIAMI FORT

Q. PLEASE DESCRIBE THE STATUS OF THE DECOMMISSIONING OF DUKE ENERGY KENTUCKY'S MIAMI FORT 6.

A. Miami Fort 6 officially retired from commercial operation on June 1, 2015. As part of the retirement of this asset, Duke Energy Kentucky is now taking action to make sure that the Miami Fort 6 facilities are decommissioned in a safe and reasonable manner. This includes removing necessary equipment and facilities to minimize safety and environmental hazards. Because of the close proximity of Miami Fort 6 and shared facilities with other Miami Fort station generating units owned by Vistras that are still in operation, the Company cannot immediately perform all necessary decommissioning and demolition work. Rather, that work must occur methodically over time so as not to interfere with operation of the other station units or personnel working at the station. Activities commenced since 2019 include:

- Removal of all asbestos containing material (ACM) from the generating unit/ductwork and facilities.
- Chimney condition assessment and minor maintenance/repairs completed.
- Continued annual Operations and Maintenance agreement for the U6 facility with Vistras.

In 2020, Vistras announced its plans to the retire Units 7 & 8 by the end of 2027, subject to regulatory approvals. The Company will coordinate with Vistra on the decommissioning of Unit 6 at the appropriate time after these retirements take place.

III. ANTICIPATED RETIREMENT OF GENERATING PORTFOLIO

Q. WHAT IS THE CURRENT ESTIMATED RETIREMENT DATE FOR EAST BEND?

A. Presently, Duke Energy Kentucky is anticipating that East Bend will retire in 2035. There are multiple drivers for this anticipated retirement, most significantly, market pressures that are negatively impacting the long-term viability of coal-fired generation.

As more fully explained by Company witness Scott Park, Duke Energy Kentucky's most recent Integrated Resource Plan (IRP), filed with the Commission in Case No. 2021-00245, analyzed several scenarios that could impact the Company's resource portfolio. These scenarios drove the development of portfolio possibilities, with the most likely result being East Bend's retirement in 2035. The Company's previous IRPs had contemplated a station retirement by 2041, the originally planned retirement date of the station. Mr. Park also discusses recent market conditions and federal regulations that have reaffirmed the reasonableness of a 2035 retirement date.

As a result, the Company is seeking in this case to align East Bend's depreciable life with its expected service life of 2035.

Q. PLEASE EXPLAIN THE CAPITAL COST DRIVER THAT IS IMPACTING EAST BEND'S REMAINING SERVICE LIFE.

A. As explained by Company witness John D. Swez, East Bend's energy is sold through the PJM markets. As more energy providers enter the marketplace with lower energy and operations costs, East Bend is projected to be less competitive and called upon to produce energy less frequently. Likewise, as coal prices increase, plants like East Bend will become more unfavorable in the competitive market. In addition to fuel prices, as stations age, maintenance on those stations increases due to wear and tear on the aging equipment. This maintenance cost also contributes to the unfavorable position of the station in the market. Duke Energy Kentucky will attempt to mitigate this exposure to market purchases and volatility to the greatest extent possible for customers.

Q. PLEASE EXPLAIN HOW THE INFLATION RECOVERY ACT IMPACTS EAST BEND'S REMAINING SERVICE LIFE.

A. As discussed in the testimony of Mr. Park, the Inflation Reduction Act of 2022 (IRA) creates significant tax credits for qualified facilities used for generating electricity that have a low to zero emission rate for greenhouse gases.[1] While these incentives are intended to directly support the development and deployment of zero emission resources, they have the indirect effect of impacting the economics of East Bend from a dispatch perspective.

[1] https://www.congress.gov/bill/117th-congress/house-bill/5376/text

Q. WHAT IS THE ANTICIPATED RETIREMENT DATE FOR WOODSDALE AND WHAT IS THE COMPANY PROPOSING WITH RESPECT TO WOODSDALE'S DEPRECIABLE LIFE IN THIS CASE?

A. The original useful life of Woodsdale assumed the asset would retire in 2032. Currently, based upon past IRP modeling and expected service lives for simple cycle combustion turbines like Woodsdale, the station is anticipated to remain in service through 2035. However, based upon the performance of the units, their regular maintenance, and the fact that these units are used for peaking service, it is likely that they will be able to remain in service for a few years beyond that. Again, in the interest of aligning the unit's depreciable life with its anticipated service life to avoid intergenerational subsidies between present and future customers, we are proposing to extend the depreciation of Woodsdale to 2040, to align with the new anticipated retirement date. This has the added benefit of offsetting some of the incremental depreciation expense associated with aligning East Bend's depreciable life to its expected service life as discussed by Ms. Lawler. In addition, extending Woodsdale's service life provides greater flexibility to the Company's resource planning and mitigates impacts to customers who would otherwise experience costs of replacing two assets at approximately the same time.

Q. HOW WILL DUKE ENERGY KENTUCKY REPLACE EAST BEND OR WOODSDALE ONCE RETIRED?

A. The Company continues to evaluate the best solution for customers. Maintaining safe, reliable, reasonable, and adequate service to customers is the priority. The

Company's most recent IRP simply described a "firm dispatchable resource" (FDR) as meeting that need for replacing East Bend. Duke Energy Kentucky is committed to achieving that goal in the most efficient manner, and will continue to monitor the market, available technologies, and any opportunities to satisfy its need to replace retired generating assets in the coming years. The Company will bring those solutions to the Commission in due time, well in advance of any retirements, to ensure there is a seamless transition for customers. While there is still time to solve the questions of "what resource will replace East Bend and Woodsdale and how?", the Company and the Commission should act now to address the disparity between the depreciable life of East Bend and its 2035 retirement. Otherwise, future customers will be paying for the retired East Bend asset and for its replacement.

IV. FILING REQUIREMENTS SPONSORED BY WITNESS

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(b).

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

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(f).

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

Q. PLEASE DESCRIBE THE INFORMATION YOU SPONSOR IN FR 16(7)(g).

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

V. CONCLUSION

Q. IS THE INFORMATION ON PLANT CONSTRUCTION PROJECTS AND OUTAGES YOU PROVIDED TO OTHER WITNESSES ACCURATE, TO THE BEST OF YOUR KNOWLEDGE AND BELIEF?

A. Yes.

Q. WAS THE INFORMATION YOU SPONSOR IN FR 16(7)(b), FR 16(7)(f) AND FR 16(7)(g), PREPARED BY YOU AT YOUR DIRECTION?

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF INDIANA	)	
	)	**SS:**
COUNTY OF HENDRICKS	)	

The undersigned, William C. Luke, VP Midwest Generation, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and that it is true and correct to the best of his knowledge, information and belief.

William C. Luke, Affiant

Subscribed and sworn to before me by William C. Luke on this 21st day of November, 2022.

TAMMY SUE ROBERTS
Hendricks County
NOTARY PUBLIC
Commission Number
NP0653013
NOTARY SEAL
My Commission Expires
OCTOBER 7, 2030
STATE OF INDIANA

NOTARY PUBLIC

My Commission Expires: 10/7/2030

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

JAMES J. MCCLAY

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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I. INTRODUCTION AND PURPOSE

Q. STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is James J. McClay, III, and my business address is 526 South Church Street, Charlotte, North Carolina 28202.

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

A. I am employed as Managing Director of Natural Gas Trading for Progress Energy Carolinas a utility affiliate of Duke Energy Kentucky, Inc. (Duke Energy Kentucky or the Company).

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

A. I received a Bachelor's Degree in Business Administration, majoring in Finance from St. Bonaventure University. I worked as a Government Bond securities trader from 1984-1998 prior to joining Progress Energy in 1998 as the Manager of Power Trading and held that position through early 2003. I became the Director of Power Trading and Portfolio Management for Progress Energy Ventures through February 2007. From March 2007 through late 2008, I was the Director of Power Trading for Arclight Energy Marketing. From March 2009 through the present, I've been employed in various managerial roles at Progress Energy and Duke Energy overseeing Natural Gas trading, origination, jurisdictional financial hedging programs, fuel oil, emissions, trading and procurement. Prior to my tenure with Duke Energy, I was employed for approximately 13 years in Capital Markets as a U.S. Government fixed income securities trader with various banks and brokers/dealers.

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

A. Yes, I have testified in a previous fuel adjustment clause (FAC) proceeding before the Kentucky Public Service Commission (Commission).

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AS MANAGING DIRECTOR OF NATURAL GAS TRADING.

A. As Managing Director of Natural Gas Trading, I manage the organization responsible for the natural gas trading, optimization, and scheduling functions for the regulated gas-fired generation assets in the Carolinas (Duke Energy Carolinas and Duke Energy Progress), Duke Energy Florida, Duke Energy Indiana, and Duke Energy Kentucky (collectively, the "Utilities"), as well as the organization responsible for power trading for Duke Energy Indiana and Duke Energy Kentucky. Additionally, I oversee the execution of the Utilities' financial hedging programs, fuel oil procurement, and emissions trading.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to discuss and explain Duke Energy Kentucky's participation in the capacity markets of PJM Interconnection LLC (PJM) and its status as a Fixed Resource Requirement (FRR) member in those capacity markets, as well as potential change in that status to a participant in the Reliability Pricing Model (RPM) Base Residual Auction (BRA) capacity auctions. I also support the Company's proposal for a comprehensive hedging program for its electric generation portfolio to mitigate market volatility for customers in the FAC as it relates to optimizing market dispatch in PJM and procurement of replacement power (economy and non-economy for outages).

II. OVERVIEW OF DUKE ENERGY'S CURRENT GENERATING RESOURCES AND PARTICIPATION IN WHOLESALE CAPACITY MARKETS

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

A. As further explained by Company witness John D. Swez, Duke Energy Kentucky currently owns and operates approximately 1,076 net installed megawatts (MW) of summer generating capacity, provided by two assets. Base load requirements are met by the East Bend Unit 2 Generating Station (East Bend), an approximate 600-megawatt (MW) (net rating) coal-fired unit located along the Ohio River in Boone County, Kentucky. The Company's peaking requirements are met with the Woodsdale Generating Station (Woodsdale), a six-unit natural gas-fired combustion turbine (CT) with approximately 476 MW (net summer rating) located in Trenton, Ohio. Additionally, the Company has approximately 8.8 MWs of distribution system tied solar that are treated as being behind the meter from PJM's perspective.

Q. PLEASE DESCRIBE THE PJM CAPACITY MARKET.

A. PJM's capacity market is called RPM. The purpose of the RPM is to provide a market construct that enables PJM to secure adequate generation resources to meet the reliability needs of the regional transmission organization (RTO). The RPM construct and the associated rules regarding how PJM members participate in the PJM capacity market is described within the PJM Open Access Transmission Tariff

(OATT) and Reliability Assurance Agreement (RAA). The PJM capacity market operates on a planning period that spans twelve months beginning June 1st and ending May 31st of each year (Delivery Year). In PJM, the capacity market structure is intended to provide transparent forward market signals that support generation and infrastructure investment.

There are two ways for a PJM member to participate in the RPM capacity structure: 1) through the RPM baseline procurement auctions otherwise known as the BRA and subsequent incremental auctions; or 2) as a self-supply FRR entity. BRAs are typically conducted three years in advance of the actual Delivery Year to allow bidders to complete construction of projects that clear the BRA. The PJM capacity market is designed to provide incentives for the development of generation, demand response, energy efficiency, and transmission solutions through capacity market payments. Another important component of RPM is that price signals are locational and designed to recognize and quantify the geographical value of capacity. PJM divides the RTO into multiple sub-regions called locational delivery areas (LDA) to model the locational value of generation.

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

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

Q. PLEASE BRIEFLY EXPLAIN PJM'S FRR PROCESS.

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

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

A. As an FRR entity, Duke Energy Kentucky must secure and commit unit-specific generation resources to meet the full load capacity requirements for its customers in advance of the PJM BRA through its FRR Plan. The FRR plan submittal schedule is currently compressed, however, under the normal schedule, the FRR Plan is forward-looking in that it covers the Delivery Year three years into the future. For example, under the current compressed timeline its most recent FRR plan was submitted in November 2022 for the 2024/2025 delivery year. Duke Energy Kentucky must own or contract and commit the unit specific generation resources to satisfy its forecasted load requirements for the period from June 1, 2024, through May 31, 2025. Presently, the load requirements include both the forecasted load of Duke Energy Kentucky's customers, as well as the reserve requirement mandated by PJM.

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

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

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

Q. WHAT ARE THE COMPANY'S LOAD REQUIREMENTS?

A. For the latest FRR plan submitted for 2024/2025, the utility's peak load was 810.5 MW and when grossed up by approximately 8.94 percent for the Forecasted Pool Requirement (FPR), which is the reserve margin used in the PJM FRR, this results in a load requirement of 883 MW. Note that when the FPR is combined with the fact that generation capacity in PJM is expressed in Unforced Capacity (UCAP) terms, the result in a more traditional approximate 15 percent Planning Reserve Margin. As the level and characteristics of the load change over time, the Company routinely assesses resource adequacy and adjusts its plans accordingly to ensure reliability in a cost-effective way for customers. Should new load come into the service territory, the Company will evaluate how that load fits within the overall utility's obligation in determining appropriate resource additions.

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

A. Duke Energy Kentucky currently has sufficient capacity to meet its load obligations; however, short-term capacity purchases may be necessary to maintain sufficient reserves and meet its capacity obligations in PJM. As was approved by the Commission in the Company's electric rate case, 2017-00321, Duke Energy Kentucky uses its Profit-Sharing Mechanism, Rider PSM, to address short-term capacity shortfalls in its FRR plan through short-term capacity purchases as well as for netting any tariffed capacity co-generation purchases including from qualified facilities as is required under the Public Utility Regulatory Policies Act (PURPA).

Duke Energy Kentucky continually evaluates its load obligations and its portfolio to ensure that there is adequate supply available. This evaluation factors in the unique circumstances and challenges the Company faces in its Northern Kentucky service territory. Duke Energy Kentucky is experiencing some load growth in its service territory and must plan to make sure the Company is able to meet such demand. While the East Bend and Woodsdale generating stations have been reliable and economic assets to satisfy base load and peaking obligations, the fact remains that Duke Energy Kentucky is heavily dependent upon these two stations to serve customers. As load demand grows, the Company's portfolio of resources should diversify to ensure there is a continued access to a stable, economic energy supply.

Q. PLEASE EXPLAIN HOW POTENTIAL NEW, LARGE CUSTOMER LOAD IN THE COMPANY'S SERVICE TERRITORY CAN IMPACT THE COMPANY'S FRR PLAN.

A. As new customer loads potentially are located in the Company's service area, these can cause challenges for the Company meeting its FRR plan. Loads that present the biggest challenge are large customers that can ramp up to high amounts quickly, such as a crypto mining operation, that may not present adequate time for the Company to acquire unit-specific generation resources, as required by the FRR construct, to meet the Company's FRR plan. In addition, an added challenge of meeting the Company's FRR plan is the PJM minimum internal resource requirement, which is the FRR requirement for the Company to locate a certain percentage of generation within the Duke Energy Ohio/ Duke Energy Kentucky (DEOK) zone. Although currently the requirement is a relatively low 34 percent, this required percentage can change every year and is dependent on how much the DEOK zone is constrained. Thus, if generation is retired inside of the DEOK zone without replacement generation and/or additional transmission, the potential remains that this percentage increases over time. Note that this requirement manifests itself in the RPM auctions as an individual zone splitting apart from the remainder of the RTO's price, as the DEOK zone has done twice in the past 5 years.

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

A. Yes. The DEOK zone has split from PJM on two recent occasions, potentially impacting the Company's access to unit-specific generation resources. For the 2020/2021 Delivery Year, capacity in the DEOK zone cleared at $130/ MW-day versus the general clearing price known as "Rest of RTO" clearing price of $76.53/MW-Day. For the 2022/2023 Delivery Year, capacity in the DEOK zone cleared at $71.69/ MW-day versus the general clearing price known as "Rest of RTO" clearing price of $50/MW-Day. While there is no guarantee that the DEOK zone capacity will continue to clear at a premium to the more generic capacity in the RTO, this zonal separation does create the potential that Duke Energy Kentucky's access to unit-specific capacity could be constrained and even priced at a premium in the future. This loss of liquidity exists regardless of whether Duke Energy Kentucky remains an FRR entity or moves at some point to full RPM participation for as long as the zonal separation exists. Because Duke Energy Kentucky's resources generally match expected load obligation for the planning period, continued investment in the Company's existing generating assets for dedicated use in its FRR plan is a crucial piece of the Company's strategy to serve customers. As such, retirements, deviations from the plan driven by either change to load requirements, resource unforced capacity could impact costs and potentially drive deficiencies in FRR Plans.

Q. PLEASE EXPLAIN THE DECISION PROCESS THE COMPANY HAS USED WITH REGARD TO BEING EITHER AN FRR OR RPM CAPACITY MEMBER.

A. Since 2012, when entering PJM, Duke Energy Kentucky has been an FRR entity located in the DEOK zone. Duke Energy Kentucky has neither been materially long or short generation. The Company found sufficient liquidity in the bilateral market to make any necessary small portfolio adjustments and has at times monetized any excess capacity from the Company's FRR plan into the RPM, remaining in the FRR has been the logical decision. Any transition from FRR to RPM depends on how customers ultimately benefit from such a change.

The Company has examined this decision and broken down the differences into six different impacts:(1) Minimum Offer Price Rule (MOPR); (2) Reserve Margin Differential; (3) 3 percent Hold Back for FRR members to monetize excess capacity; (4) FRR deficiency penalties; (5) Market Liquidity Differences; and (6) Physical vs. Financial Capacity Performance penalty option.

A short summary of each item is discussed below:

- MOPR – Recently, clarification has occurred with regards to PJM's MOPR ruling. Prior to this rule change, if Duke Energy Kentucky were to switch to an RPM member, there was the potential that Duke Energy Kentucky would be required to offer certain generation resources into the RPM auctions at a minimum price that was potentially high enough that the resource did not clear in the specific RPM auction, either the BRA or a subsequent incremental auction. Thus, the potential existed for Duke Energy Kentucky to "pay twice" for capacity; once to build/maintain a generation asset and again to purchase its load in the capacity auction, if the asset didn't clear the auction there would be no generation revenue to offset the load purchase. Today, there are now two conditions that must be true in order eliminate the MOPR risk. The first condition is that Duke Energy Kentucky doesn't have Buyer-Side Market Power (BSMP), which occurs when an LSE offers generation at a lower price to reduce its overall exposure to the market. The second condition is that Duke Energy Kentucky doesn't have Conditioned State Support, which occurs if a state is giving a unit a subsidization based on how the unit is offered into the capacity market. For the most recent planning year, Duke Energy Kentucky certified that these two conditions did not occur, and PJM agreed with that determination. Thus, the new MOPR rule virtually eliminates the MOPR risk and makes Duke Energy Kentucky indifferent to participation in FRR or RPM.

- Reserve Margin Differential – FRR entities are required to purchase a fixed reserve margin, which as discussed previously is approximately 15 percent. However, RPM entities purchase on a sloped demand curve, which can cause additional purchases as the price of the auction moves lower, meaning that at lower prices, loads purchase more capacity to ensure greater reliability. The net financial impact of this concept to the

Duke Energy Kentucky customer will be discussed more below as it relates to the 3 percent hold back.

- 3 percent Hold Back for FRR members to monetize excess capacity – As Duke Energy Kentucky has done in recent auctions, FRR entities are required to hold back 3 percent of their load if they have excess generation that they want to monetize in the BRA auction. Thus, since currently Duke Energy Kentucky is an FRR member, approximately 30 MW is not able to be monetized in the BRA, whereas it could sell this additional amount into the BRA if it were under RPM.
    - The net financial result of the impact of the Reserve Margin Differential added to the 3 percent Hold Back for FRR members, at an average clearing price, is approximately a cost of $1.8 million per year. Thus, by remaining in the FRR today and not switching to RPM, the Company believes that it is saving approximately $1.8 million annually for the Duke Energy Kentucky customer. Note that this assumes that the incremental auctions clear at a lower price than the BRA; if the incremental auctions were to start clearing at a price more similar to the BRA, the savings from remaining an FRR entity is greater since the 3 percent holdback could be monetized in the incremental auctions as an FRR member.
- FRR deficiency penalties – Potential FRR deficiency penalties can be very severe if Duke Energy Kentucky was unable to meet its initial FRR

plan submitted prior to the BRA. As an example, if the Company were short 600 MW, a penalty greater than $100 million is possible, along with very likely FERC referral and even possible removal from FRR status. Due to this severe penalty, it is critical that Duke Energy Kentucky meet its annual initial FRR plan. As the Company gets closer to a potential East Bend retirement and replacement generation, transition to a new generation asset has far less risk under RPM than under the FRR, as replacement capacity is more likely to be able to be purchased under the RPM than under FRR.

- Market Liquidity Differences – FRR entities cannot access the PJM RPM auction to purchase capacity for shortfalls to fulfill its FRR plan. Shortfalls to the FRR plan could be caused by a sudden customer load addition, changes in generation supply due to a retirement, or unexpected change in a units Equivalent Forced Outage Rate (EFOR). These shortfalls may not be able to be managed with the options available in the FRR and thus, present additional risk of not meeting the FRR plan with the penalties discussed above.
- Physical vs. Financial Capacity Performance penalty option – When a generating unit is assessed a capacity performance penalty, FRR members have the additional choice to elect having a physical penalty option instead of a financial charge that is not available in the RPM capacity construct. In lower capacity price environment, the FRR

physical penalty tends to be a lower cost alternative than the financial option, thus there is an additional benefit to remaining an FRR entity.

Summarizing all the above, the Company believes that remaining in the FRR capacity construct is currently the right option for Duke Energy Kentucky's customers. However, as the Company gets closer to a potential retirement of a generation resource or if large additional loads enter the Duke Energy Kentucky service territory, progression to the RPM may make sense at that time.

Although it is possible to remain an FRR participant, constructing or purchasing a new generating unit and retiring East Bend simultaneously takes perfect coordination, requires replacement with a generation resource likely located within DEOK, and comes with risks and potential penalties. For example, if a new generation unit was planned but ended up being delayed, under RPM it is possible to still retire the existing unit and purchase the shortfall capacity obligation from PJM between the retirement of the unit and the commercial operation date of the new unit. This scenario is still possible under the FRR construct, but potentially more difficult to accomplish since the replacement capacity either may not be available or is available but not located in the DEOK zone. The Company will continue to monitor its participation.

III. DUKE ENERGY KENTUCKY'S NATIVE HEDGING PROPOSAL

Q. HOW DOES DUKE ENERGY KENTUCKY MANAGE THE RISKS OF EXPOSURE TO MARKET PRICES FOR ITS CUSTOMERS TODAY?

A. Duke Energy Kentucky manages these risks through its long-term strategy through the integrated resource planning (IRP) process. Previously, the Company also utilized a Commission-approved back-up power supply plan whereby the Company managed risks through the PJM daily energy market during forced outages and fixed forward contract purchases during scheduled outages. The purpose of the back-up supply plan was to mitigate the risk of price spikes during scheduled outages because the price for back-up power would be fixed. The Company's hedging strategy provided the flexibility to optimize the actual outage schedules under changing power markets and unit availability conditions through purchasing fixed price financial hedges in the liquid energy markets. Duke Energy Kentucky would make its forward contract purchases a few months in advance of the scheduled outages to lock in the power prices. If prices appeared to be increasing, the plan provided the flexibility to make the forward contract purchases for long-term periods. If forward prices appeared flat or falling, the Company would postpone these purchases. The Company's plan provided flexibility to modify executed forward contract positions if scheduled outage dates are modified, by utilizing the liquidity of the power markets to unwind existing contracts and purchase new contracts to match new scheduled outage dates.

The back-up supply plan was reviewed and approved periodically by the Commission. The Company last sought approval of its back-up supply plan in Case No. 2021-00086.[1] The Company had requested approval of its hedging strategy through May 31, 2024. By Order dated November 30, 2021, the Commission approved the Company's plan through May 31, 2022, *only* and denied it for future

[1] *In the Matter of Electronic Back-up Power Supply Plan of Duke Energy Kentucky, Inc,* Case No. 2021-00086, Ky. P.S.C. Order, Nov. 30, 2021.

delivery years.[2] Accordingly, the Company is not currently operating under an approved back-up supply plan.

Q. DOES DUKE ENERGY KENTUCKY PROPOSE TO MAKE ANY CHANGES TO THE WAY IT MANAGES CUSTOMER EXPOSURE TO MARKET PRICES AS PART OF THIS CASE?

A. Yes. Duke Energy Kentucky is proposing to implement a more comprehensive hedging strategy.

Q. PLEASE EXPLAIN THE COMPANY'S NATIVE HEDGING PROPOSAL.

A. Utilizing the PJM AD Hub financial forward power markets that have available financial products to hedge exposures for monthly, weekly, and daily terms, the Company proposes to expand customer exposure price risk mitigation to include scheduled outages/derates, forced generation outages/derates and time periods where market prices are lower than operating the Company's owned generation assets. Utilizing the financial markets when generation costs exceed market prices reduces customer costs locking in economic price certainty. During forced and scheduled outage/derate periods, forward financial hedging reduces customer exposure to daily spot market volatility. Duke Energy Kentucky proposes a hedge horizon of a rolling 1 year time period. Based on the type of exposure being mitigated, financial power hedges can be executed over time to lock in power prices and minimize exposure to the volatile spot market price movements for scheduled and forced outages.

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[2] *Id.*

Proactive financial and economic hedging benefits Duke Energy Kentucky customers. During forced and scheduled outage/derate periods Duke Energy Kentucky has proprietary specific knowledge and can protect the customers from future market volatility. From time to time, economic financial hedges can lower costs for customers by leveraging market prices when Duke Energy Kentucky's expected dispatch costs exceed market prices.

Q. WHY IS DUKE ENERGY KENTUCKY PROPOSING THIS CHANGE?

A. Spot market Power prices have been volatile since the Company joined PJM markets in 2012. Through the end of September 2022, the average on-peak daily PJM AEP-Dayton Hub Day Ahead LMP was $40.81/MWH. For the same period, average daily AEP Dayton Hub Real Time LMP was $40.35/MWH. However, there was a wide range of prices. Day Ahead daily price settled between $15.98/MWH and $580.27/MWH while Real Time price went from as low as $13.38/MWH to as high as $706.97/MWH. There were 85 days where Day Ahead daily price exceeded $100/MWH and 87 days in the same period that daily Real Time peak power prices reached above $100/MWH. Moreover, we observed hourly AEP-Dayton Hub Day Ahead or Real Time LMP over $100/MWH in most months since January of 2012, with the highest LMP at $2,785.01/MWH and the lowest at negative $232.53/MWH.

To help mitigate the exposure to the daily market volatility, if the position warrants, the Company can enter fixed price forward power purchase contracts that are financially settled on a specific future date at PJM AEP-Dayton Day-Ahead or Real Time LMPs. Locking in price certainty for customers helps reduce customer exposure to FAC volatility. The applicable LMPs on the settlement date for these contracts may be higher or lower than the price the Company paid for the forward contract and the Company will either pay or be refunded the difference.

Q. HOW DOES DUKE ENERGY KENTUCKY PROPOSE TO PASS CREDITS AND CHARGES FROM NATIVE HEDGING THROUGH TO CUSTOMERS?

A. Under past Back-up Supply plans, the Company was allowed to recover costs of replacement power purchased from PJM and financial hedges for scheduled outages via its fuel adjustment clause. For forced outages/derates, with limits, cost of replacement power from PJM was also recovered via its fuel adjustment clause. The Company recovers the portion of replacement power costs not recovered in the fuel adjustment clause in base rates. Per the Commission Order in Case No. 2017-00321, any annual amount of expenses for forced outage replacement power costs not recovered in the FAC over or under the amount included in base rates is deferred for recovery in future base rate cases. As customers have similar exposure to market prices during periods of scheduled outages, forced generation outages, and economic market purchases, the Company believes it is in customers' best interest to manage price exposure in all these cases.

Therefore, Duke Energy Kentucky proposes to treat the financial hedge results, both gains and losses through the FAC. Forced outage power replacement costs from PJM would be recovered (either through base rates or through the fuel adjustment clause.)

Q. WHY IS A COMPREHENSIVE HEDGING PLAN NEEDED NOW?

A. Commencing a comprehensive hedging program provides immediate benefits to customers given the number of risk factors that can impact prices and trends. Duke Energy Kentucky does not speculate on market prices; however, the energy markets have fundamentally changed in the US and rest of the world. The power markets are dependent and driven by the underlying interrelated fuel markets. As the US economy has recovered from Covid lockdowns, the US coal and gas production growth has lagged demand due to producers focus on capital discipline while the US and global demand has grown causing the US to compete with global export coal and liquified natural gas markets. Foreign demand for energy and global conflict can result in substantial or frequent changes in prices contributing to the volatility of energy prices in the US. These factors and others have caused spot and forward market volatility to increase changing the future landscape for coal and gas supply price stability. Thus it is difficult to accurately predict where power prices will be in future months. Duke Energy Kentucky believes a more comprehensive hedge program to limit customer exposure to spot prices will increase price certainty and in customers' best interest.

Q. WILL IMPLEMENTING A NATIVE HEDGING PLAN AS YOU DESCRIBE RESULT IN LOWER RATES FOR CUSTOMERS?

A. The results of any hedging activity may or may not result in net fuel cost savings. However, Duke Energy Kentucky believes having a balanced and more comprehensive fuel price risk management approach that results in greater fuel cost certainty is in the customer's best interest.

Q. WILL IMPLEMENTING HEDGING PLAN AS YOU DESCRIBE REDUCE PRICE VOLATILITY RISK TO CUSTOMERS? PLEASE EXPLAIN.

A. Purchasing power hedges, limiting price risk exposures and providing fuel price certainty is an important part of managing fuel price volatility. A more comprehensive hedge plan is a proactive measure to mitigate exposure to volatile spot energy prices and increase price certainty for customers.

IV. CONCLUSION

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

A. Yes.

VERIFICATION

STATE OF NORTH CAROLINA)

) **SS:**

COUNTY OF ~~MECKLENBURG~~)
Lincoln

The undersigned, James McClay, Managing Director Natural Gas, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

James McClay Affiant

Subscribed and sworn to before me by James McClay on this 18th day of November, 2022.

WENDY J. HEAFNER
NOTARY
PUBLIC
LINCOLN COUNTY, NC

NOTARY PUBLIC

My Commission Expires: 10/30/2027

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

MAX W. McCLELLAN

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC.

December 1, 2022

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I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Max W. McClellan. My business address is 400 South Tryon Street, Charlotte, North Carolina 28202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as a Lead Load Forecasting Analyst in the Load Forecasting group. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

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

A. I received a Bachelor of Science degree in Mathematical Decision Sciences from the University of North Carolina at Chapel Hill in 2013.

I joined Duke Energy Corp. in October 2018 as a Senior Rates & Regulatory Strategy Analyst in the Pricing and Regulatory Solutions team. My current title is Lead Load Forecasting Analyst.

Q. PLEASE BRIEFLY DESCRIBE YOUR DUTIES AND RESPONSIBILITIES AS A LEAD LOAD FORECASTING ANALYST.

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

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

A. No.

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

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

II. LOAD FORECAST

Q. DID YOU PREPARE THE COMPANY'S LOAD FORECAST FOR THIS RATE CASE?

A. Yes, I did.

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

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

The forecast methodology is essentially the same as that presented in Duke Energy Kentucky's past Integrated Resource Plans filed with the Kentucky Public Service Commission (Commission), with a major difference being that the models have been updated to include more recent data.

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

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

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

Q. DO YOU ALSO PRODUCE THE COMPANY'S FORECAST FOR THE NUMBER OF CUSTOMERS?

A. Yes, the forecasts for the number of customers are produced using the same modeling techniques and data sources as our forecasts for volumes.

Q. HOW IS THE ENERGY FORECAST DEVELOPED?

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

Q. WHAT ARE THE PRIMARY FACTORS AFFECTING ENERGY USAGE?

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

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

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

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

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

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

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

A. The output of the model estimation is adjusted for the impacts of projected growth in behind-the-meter solar generation, electric vehicle usage, and the impacts of new energy efficiency programs. The Company may adjust the forecast for anticipated increases in load due to a major new customer or a significant expansion at a current customer's site. For the load forecast, an adjustment was made to add load for one large commercial customer that has committed to doing business within the region and is located in the Company's service territory.

Q. PLEASE EXPLAIN HOW THE PEAK FORECASTS ARE DEVELOPED.

A. The Company projects both a winter and a summer peak for the total region using econometric equations that forecast peak demand as a function of economic growth, as measured by energy sales, end-use data, and several key weather factors. The Duke Energy Kentucky peak load forecast is estimated separately from any other system peak. The model is exposed to monthly peak data, with normalized weather conditions for the day of peak based on thirty-year data. Attachment MWM-1 shows the monthly peak weather normal degree days used to compute peaks for Duke Energy Kentucky.

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

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

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

A. Yes. It is my understanding that, according to the Commission's Order, in Administrative Case 2008-00408, utilities must explain consideration of cost-effective energy efficiency resources and the impacts of such resources on the utility test year. For Duke Energy Kentucky, incremental peak load reductions due to current and future UEE programs are used to adjust the historical data as part of the process of calculating the load forecast. The projected incremental impact of existing programs for the years 2022 through 2023 is an additional reduction of almost 58,000 mWh total, and 6 mW at time of peak. The load forecast provided here reflects those projected energy efficiency impacts.

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

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

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

A. Yes, the econometric forecasting methodology used to create the load forecast in this case is basically the same as that used by the Company in prior cases.

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

A. Yes, I am.

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

A. Yes. While other utilities might use a variety of load forecasting approaches, such as econometric, end-use, trend analysis, or time series analysis, nearly all of the utilities I am familiar with use the same or similar factors as listed above as considered by Duke Energy Kentucky, to varying degrees. In addition, price forecasts for alternate fuels including natural gas and fuel oil are considered. I am aware of survey data indicating that many large utilities utilize an approach consistent with this methodology.

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

A. Under any approach to load forecasting, judgment is an essential element. Each utility must use the approach that, in its judgment, best suits its particular situation, taking into account the various factors. Examples of this would be advice from the sales team about conditions on the ground that are related to regional growth, or advice from the managers of energy efficiency and demand side management programs that provide incentives for customers to reduce energy usage.

Q. PLEASE DESCRIBE ATTACHMENT MWM-2.

A. Attachment MWM-2 is a summary of Duke Energy Kentucky's energy forecast. The projected annualized rate of growth in total retail sales—measured on a calendar basis—for the five-year period 2022 to 2027 is 0.8 percent and for the ten-year period 2022 to 2032 is 0.7 percent per year.

That growth rate—while mathematically correct for the period in question—is not adequate for summarizing several dynamics that affect demand for energy during the near term. As I noted, there is also adjustments for one very large commercial customer that has committed to doing business within the region and is located in the Company's service territory.

Q. PLEASE DESCRIBE ATTACHMENT MWM-3

Attachment MWM-3 is a summary of Duke Energy Kentucky's peak load forecast. The projected annualized rate of growth in energy demand at time of peak is 0.8 percent for the five-year period, and 0.7 percent for the ten-year period.

III. <u>DEGREE DAY DATA USED IN THE FORECAST</u>

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

A. Weather is expressed in terms of Heating Degree Days (HDD) and Cooling Degree Days (CDD).

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

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

Heating Degree Days = Base Temperature – Daily Average Temperature

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

Cooling Degree Days = Daily Average Temperature – Base Temperature

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

Q. PLEASE EXPLAIN "NORMAL" WEATHER.

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

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

A. Duke Energy Kentucky uses a rolling thirty-year period to calculate the Normal Weather in its electric and natural gas forecasts.

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

A. Yes. NOAA is responsible for monitoring climate conditions in the United States. Additional information about NOAA is available at their web site at www.noaa.gov. The standard time period prescribed by the United Nations World Meteorological Organization for measuring climate conditions is thirty years, and NOAA updates its calculations for the United States for these thirty-year periods at the end of each decade. The most current thirty-year period used by NOAA is 1991-2020.

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

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

A. As a new year of weather data—subject to a delay—becomes available, it is our practice to roll off the oldest year and replace it. The years 1991-2020 were used to calculate normal weather.

Q. WHAT HAS BEEN THE LONG-TERM TREND IN AVERAGE TEMPERATURES FOR COVINGTON, KENTUCKY?

A. The years 1991 through 2020 suggest a slight warming trend. Basic econometric analysis confirms that this trend is statistically significant under several different specifications, including ones that use data from years before that period. The graph in Attachment MWM-4 shows these charts.

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

A. The last ten years indicate a slight increase of cooling degree days during the summer; however, because so few observations are involved, these results are not statistically significant. The data on winter heating degree days show a very slight declining trend over this period.

Q. HOW DO THE ACTUAL ANNUAL HEATING DEGREE DAYS FOR THE LAST TEN YEARS FOR COVINGTON, KENTUCKY, COMPARE TO THIRTY-YEAR NORMALS?

A. See Attachment MWM-5 for a graph comparing the annual degree days in heating/cooling to the forecasts of the thirty-year normal scheme, as well as the ten-year normal scheme and the NOAA static thirty-year normal. The ten-year normal calls for slightly more extreme summer weather (cooling degree days) than the thirty-year normal. Annual weather is much more variable than the degree to which the various forecasts vary from each other. The difference between the ten-year normal and thirty-year normal is not as dramatic with regard to winter weather (heating degree days), wherein both methods for calculating normal weather appear to be similar upon visual inspection.

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

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

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

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

and Y = Actual Annual Degree Days

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

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

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

A. From 2018 through 2021, the Company's UEE programs are estimated to have reached an annual incremental savings level of nearly 40,000 MWh and reduced the summer peak load by—in some cases—as much as 6 MW.

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

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

- Program 1: Low Income Services Program
- Program 2: Residential Energy Assessments Program

- Program 3: Residential Smart $aver® Efficient Residences Program
- Program 4: Residential Smart $aver® Energy Efficient Products Program
- Program 5: Smart $aver® Prescriptive Program
- Program 6: Smart $aver® Custom Program
- Program 7: Power Manager® Program
- Program 8: PowerShare®
- Program 9: Low Income Neighborhood
- Program 10: My Home Energy Report
- Program 11: Non-Residential Small Business Energy Saver Program
- Program 12: Non-Residential Pay for Performance[1]
- Program 13: Peak Time Rebate Pilot Program

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

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

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

[1] Marketed as Smart $aver® Performance

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

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

Q. PLEASE DESCRIBE THE RTP PROGRAM.

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

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

A. The Duke Energy Kentucky customer accounts that participate in RTP generally provide a peak load reduction. Historically, the load impact from the RTP program has been projected to be approximately 1 MW. There have not been significant changes to the program. Impacts from RTP and any other programs can be treated as embedded in the load forecast, as they fall within the margin of error of our models.

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

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

V. FILING REQUIREMENTS AND INFORMATION SPONSORED BY WITNESS

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

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

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

A. Yes, I supplied Mr. Carpenter with the gas Mcf and electric kWh sales for the forecasted portion of the base period, consisting of the twelve months ending February 28, 2023, and the forecasted test period, consisting of the twelve months ending June 30, 2024.

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

A. Yes.

VI. CONCLUSION

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

A. Yes.

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

A. Yes.

VERIFICATION

STATE OF North Carolina)
) **SS:**
COUNTY OF Orange)

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

Max W. McClellan Affiant

Subscribed and sworn to before me by Max W. McClellan on this 29th day of November, 2022.

TEJAL PATEL
NOTARY
My Comm. Exp.
11-28-2026
PUBLIC
WAKE COUNTY, NC

NOTARY PUBLIC

My Commission Expires: November 28, 2026

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

	Forecast Day of Peak	Heating Degree Days	Implied Average Temp	Cooling Degree Days	Implied Average Temp
1/1/2022	1/19/2022	51.72	7.28	0	--
2/1/2022	2/8/2022	31.67	27.33	0	--
3/1/2022	3/3/2022	24.35	34.65	0	--
4/1/2022	4/18/2022	0	--	5.59	70.59
5/1/2022	5/31/2022	0	--	4.76	69.76
6/1/2022	6/21/2022	0	--	9.91	74.91
7/1/2022	7/19/2022	0	--	18.62	83.62
8/1/2022	8/2/2022	0	--	16.48	81.48
9/1/2022	9/2/2022	0	--	8.11	73.11
10/1/2022	10/4/2022	0.18	58.82	0.63	65.63
11/1/2022	11/28/2022	30.58	28.42	0	--
12/1/2022	12/20/2022	27.15	31.85	0	--

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

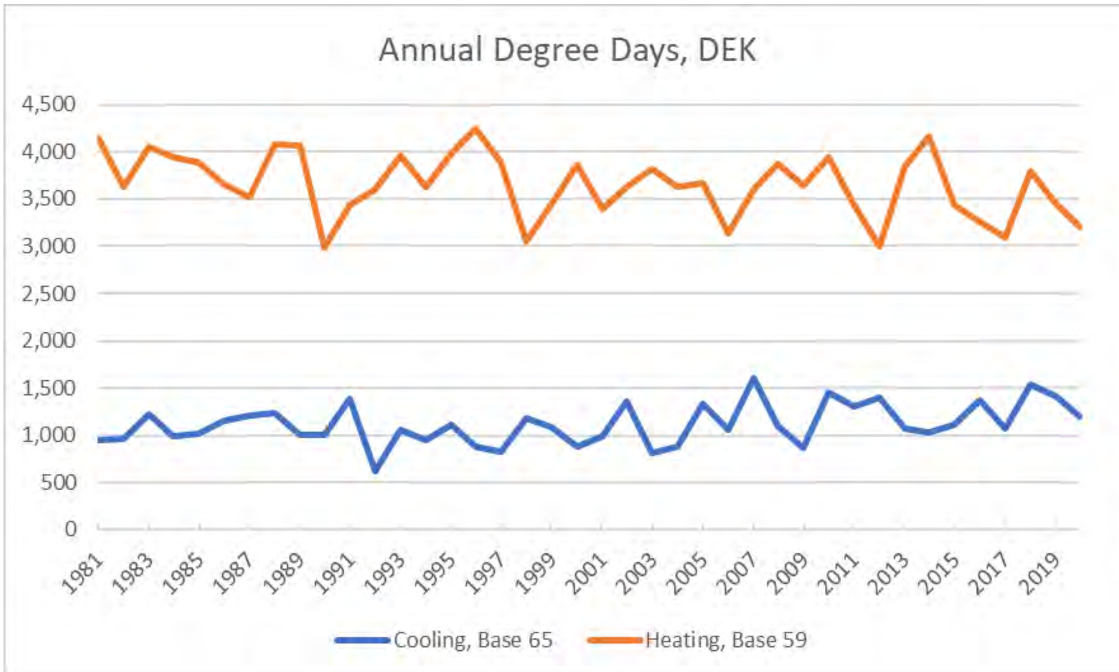
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
								(1+2+3+4+5+6)
					STREET-HWY			TOTAL
	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	LIGHTING	OPA	OTHER	CONSUMPTION
-5	2017	1,395,234	1,450,924	800,034	15,077	276,772	1,136	3,939,177
-4	2018	1,563,656	1,479,511	814,989	14,317	284,443	689	4,157,605
-3	2019	1,512,664	1,460,450	817,559	13,759	275,132	928	4,080,492
-2	2020	1,477,914	1,416,427	746,182	13,827	187,140	591	3,842,080
-1	2021	1,516,485	1,536,653	751,561	13,143	150,835	666	3,969,344
0	2022	1,477,026	1,479,917	796,145	13,617	266,183	829	4,033,716
1	2023	1,483,566	1,552,620	791,001	13,581	267,808	829	4,109,404
2	2024	1,491,406	1,560,974	787,931	13,563	267,962	829	4,122,665
3	2025	1,516,641	1,609,760	781,941	13,549	268,540	829	4,191,260
4	2026	1,525,979	1,605,549	775,116	13,534	269,375	829	4,190,382
5	2027	1,542,689	1,606,246	769,969	13,524	270,809	829	4,204,066
6	2028	1,558,264	1,608,843	767,333	13,516	272,456	829	4,221,242
7	2029	1,575,040	1,609,709	765,066	13,510	274,015	829	4,238,168
8	2030	1,599,006	1,647,150	762,859	13,438	275,594	829	4,298,877
9	2031	1,615,818	1,645,156	761,836	13,386	277,013	829	4,314,038
10	2032	1,638,609	1,650,163	760,522	13,356	278,306	829	4,341,785
11	2033	1,664,855	1,653,966	758,148	13,346	279,418	829	4,370,562
12	2034	1,686,490	1,655,411	754,852	13,339	280,315	829	4,391,236
13	2035	1,716,110	1,662,997	753,129	13,338	281,297	829	4,427,700
14	2036	1,755,426	1,680,893	754,123	13,339	282,505	829	4,487,115
15	2037	1,779,930	1,685,429	755,732	13,340	283,521	829	4,518,781
16	2038	1,812,453	1,698,219	757,742	13,342	284,459	829	4,567,044
17	2039	1,844,418	1,711,786	759,927	13,343	285,288	829	4,615,591
18	2040	1,876,353	1,717,136	762,238	13,329	286,146	829	4,656,031
19	2041	1,904,661	1,721,099	764,160	13,318	286,930	829	4,690,996
20	2042	1,942,978	1,733,124	766,039	13,308	287,777	829	4,744,055

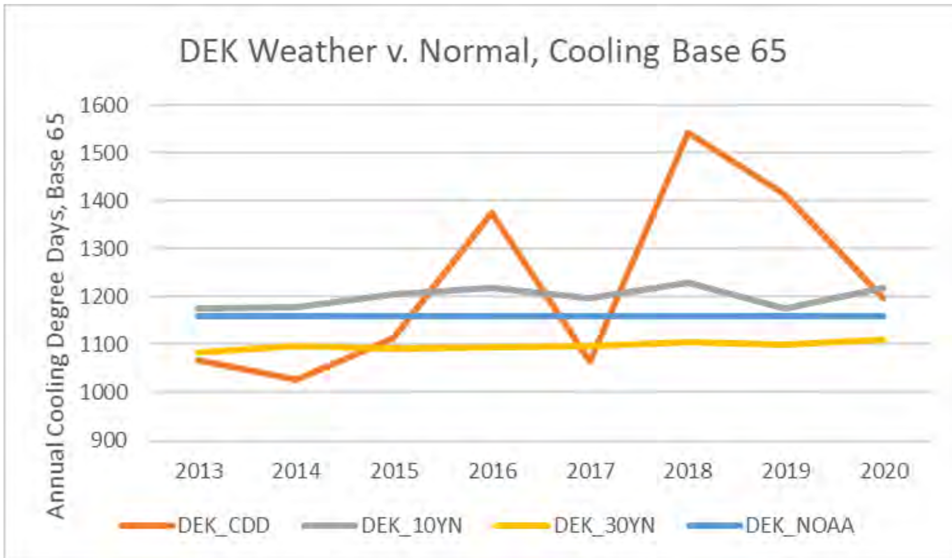
(a) Figures in years -5 through -1 reflect the impact of historical demand side programs

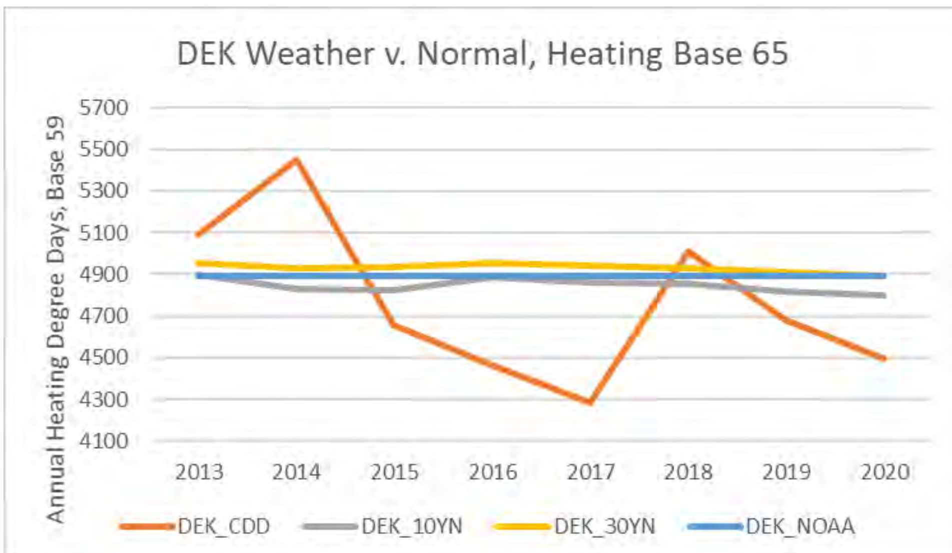
Duke Energy Kentucky
SYSTEM SEASONAL PEAK LOAD FORECAST (MEGAWATTS) (a,b)

		SUMMER			WINTER (e)		
	YEAR	LOAD	CHANGE (c)	PERCENT CHANGE (d)	LOAD	CHANGE (c)	PERCENT CHANGE (d)
-5	2017	841			733		
-4	2018	857	16	1.9%	797	64	8.7%
-3	2019	849	-8	-0.9%	821	24	3.0%
-2	2020	809	-40	-4.7%	742	-79	-9.6%
-1	2021	838	29	3.6%	678	-64	-8.6%
0	2022	822	-16	-1.9%	733	55	8.2%
1	2023	836	14	1.7%	747	14	1.9%
2	2024	840	4	0.5%	747	0	-0.1%
3	2025	851	11	1.3%	763	16	2.1%
4	2026	853	1	0.1%	759	-4	-0.5%
5	2027	854	2	0.2%	757	-1	-0.2%
6	2028	857	3	0.3%	754	-3	-0.4%
7	2029	860	3	0.3%	755	1	0.1%
8	2030	870	10	1.2%	768	12	1.6%
9	2031	874	3	0.4%	768	0	0.0%
10	2032	879	6	0.7%	769	1	0.1%
11	2033	885	5	0.6%	765	-4	-0.5%
12	2034	890	5	0.6%	764	-1	-0.1%
13	2035	898	8	0.9%	774	10	1.3%
14	2036	911	13	1.5%	792	18	2.3%
15	2037	919	8	0.9%	798	6	0.7%
16	2038	931	12	1.4%	797	-1	-0.1%
17	2039	942	10	1.1%	802	5	0.7%
18	2040	950	8	0.8%	802	-1	-0.1%
19	2041	956	6	0.7%	823	22	2.7%
20	2042	974	18	1.9%	833	9	1.2%

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


Annual Degree Days, DEK
4,500
4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
2019
Cooling, Base 65
Heating, Base 59


DEK Weather v. Normal, Cooling Base 65
Annual Cooling Degree Days, Base 65
1600
1500
1400
1300
1200
1100
1000
900
2013
2014
2015
2016
2017
2018
2019
2020
DEK_CDD
DEK_10YN
DEK_30YN
DEK_NOAA


DEK Weather v. Normal, Heating Base 65
Annual Heating Degree Days, Base 59
5700
5500
5300
5100
4900
4700
4500
4300
4100
2013
2014
2015
2016
2017
2018
2019
2020
DEK_CDD
DEK_10YN
DEK_30YN
DEK_NOAA

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 New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief.	)))))))	Case No. 2022-00372

DIRECT TESTIMONY OF

DOMINIC “NICK” J. MELILLO

ON BEHALF OF

DUKE ENERGY KENTUCKY, INC

December 1, 2022

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PAGE

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Dominic "Nick" J. Melillo and my business address is 139 East Fourth Street, Cincinnati, OH 45202.

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

A. I am employed by Duke Energy Business Services LLC (DEBS) as Director Distribution Asset Management. DEBS provides various administrative and other services to Duke Energy Kentucky, Inc., (Duke Energy Kentucky or the Company) and other affiliated companies of Duke Energy Corporation (Duke Energy).

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

A. I earned a Bachelor of Science degree in Mechanical Engineering from Ohio University in 2000, and a Masters in Business Administration degree from Xavier University in 2012.

Starting in 2001, I worked in various engineering and project manager roles in Duke Energy's power generation organization. In 2014, I transferred to Duke Energy's electric distribution organization. Since 2015, I have held various leadership roles of increasing responsibility in the electric distribution organization.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AS DIRECTOR ASSET MANAGEMENT.

A. In my current role, I am responsible for the electric distribution capacity planning, reliability grid investments, power quality, and maintenance programs for Duke Energy's regulated utility operations in Kentucky, Ohio, and Indiana.

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

A. No.

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

A. The purpose of my testimony is: (1) to describe Duke Energy Kentucky's electric delivery system; (2) to explain Duke Energy Kentucky's overall policies relating to the design, construction, operation, and maintenance of the Company's electric delivery facilities; and (3) to explain the need for continued investment in the electric delivery system in order to maintain system reliability. I also sponsor part of the information in the capital budget relating to the Company's local transmission and distribution facilities contained in Filing Requirements (FR) 16(7)(b), FR 16(7)(f) and FR 16(7)(g), which I provided to Duke Energy Kentucky witness Mr. Grady "Tripp" S. Carpenter for the forecasted financial data.

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

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

A. Duke Energy Kentucky's electric delivery system is used, among other things, to deliver retail electric service to approximately 149,200 customers located throughout our service area in the Commonwealth of Kentucky and is spread throughout five counties in the northern part of the Commonwealth. Duke Energy Kentucky owns and operates all of its electric distribution and local transmission facilities.

Its parent, Duke Energy Ohio, owns and operates, subject to the functional control of PJM Interconnection, LLC, (PJM) the bulk transmission facilities located in Duke Energy Kentucky's service territory. Duke Energy Kentucky owns, operates, and maintains approximately 126 miles of transmission lines operating at 69 kilovolts (kV) and approximately 2,228 miles of primary distribution lines operating at 34.5 kV or lower and approximately 814 miles of secondary distribution circuits operating at 480 volts or below. The delivery system also includes approximately 39 combined transmission and distribution substations with a combined capacity of approximately 3,433,000 kVA and various other equipment and facilities.

The Duke Energy Kentucky electric system is interconnected with East Kentucky Power Cooperative via a 69-kV tie line at the Kenton substation. It is primarily served by transmission facilities within Duke Energy Midwest which, in turn, is directly interconnected with a total of ten transmission owning utilities, the majority of whom are in PJM or Midcontinent Independent System Operator (MISO).

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

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

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S ELECTRIC DISTRIBUTION SYSTEM HAS GROWN SINCE MARCH 31, 2021 (THE END OF THE TEST PERIOD FROM DUKE ENERGY KENTUCKY'S LAST RETAIL ELECTRIC RATE CASE).

A. Duke Energy Kentucky's electric distribution system has grown considerably. In the Company's last electric base rate case, Duke Energy Kentucky's forecasted cost of electric distribution system plant in service was $581,657,991 (thirteen-month average forecasted balance ending March 31, 2021), As of March 31, 2021, Duke Energy Kentucky's actual cost of electric distribution system plant in service was $597,672,897. The Company's forecasted test year (thirteen-month average balance ending June 30, 2024) in this case is projecting the balance to be $697,001,290.

As a further example, by June 30, 2024, Duke Energy Kentucky plans to increase the distribution substation transformer capacity by approximately 91 MVA. Investments like these have been necessary to maintain safe, reliable, efficient, and economical electric distribution service for our existing customers.

Q. PLEASE GENERALLY DESCRIBE HOW DUKE ENERGY KENTUCKY'S ELECTRIC TRANSMISSION SYSTEM HAS GROWN SINCE MARCH 31, 2021 (THE END OF THE TEST PERIOD FROM DUKE ENERGY KENTUCKY'S LAST RETAIL ELECTRIC RATE CASE).

A. Duke Energy Kentucky's electric transmission system has grown considerably. In the Company's last electric base rate case, Duke Energy Kentucky's forecasted cost of electric transmission system plant in service was $72,371,702 (thirteen-month average forecasted balance ending March 31, 2021), As of March 31, 2021, Duke Energy Kentucky's actual cost of electric transmission system plant in service was $93,637,637. The Company's forecasted test year (thirteen-month average balance ending June 30, 2024) in this case is projecting the balance to be $134,522,697.

Q. PLEASE EXPLAIN WHAT HAS DRIVEN THIS INVESTMENT.

A. A primary driver for this additional investment has been, and will be, localized load growth. Duke Energy Kentucky is experiencing significant development in specific areas of its service territory in Northern Kentucky where additional capacity and facilities are necessary to provide safe, reliable, and adequate service. This growth includes commercial, retail, industrial, and residential customers.

While the Company's total load growth across its entire system may not appear to be changing significantly, this localized growth on specific circuits necessitates investment where the current facilities are not able to support the development. An example of this localized growth is the Aero Substation project. This new substation is driven by growth related to several large customer projects that have located in Boone and Kenton County. Between these projects, approximately 1,725 acres of land is being developed resulting in approximately 9,922,000 square feet of building space and projected demand of approximately 123 MVA.

Additionally, the Company has focused its investment strategy into maintaining and improving reliability in its electric delivery system. Such reliability investments include, but are not limited to, a measured deployment of self-optimizing grid technologies designed to minimize outage durations and enable faster restorations, as well as the replacement of aging infrastructure. Additionally, investments are also now necessary to meet our customers' evolving and increased expectations, all of which I describe later in my testimony.

These investments are necessary to continue to provide our customers with the safe, reliable and efficient service they desire and deserve.

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

A. Yes, they are used daily to provide safe, reliable, efficient and economical electric delivery service to our customers.

Q. PLEASE GENERALLY DESCRIBE HOW THE TRANSMISSION AND DISTRIBUTION SYSTEMS ARE DESIGNED, CONSTRUCTED AND OPERATED.

A. The electric transmission system is designed to deliver bulk electric power from local generating plants and other resources to regional substations, or to interconnect with other systems in order to enhance system reliability. The transmission voltages used by Duke Energy Kentucky are 69 kV and 138 kV. As I previously mentioned, Duke Energy Ohio owns the bulk transmission system in northern Kentucky, consisting of 138 kV and above. There are also two 69 kV circuits in Kentucky owned by Duke Energy Kentucky. The system generally consists of steel tower or wood pole transmission lines and substations with power transformers, switches, circuit breakers and associated equipment. The physical design of the system is generally governed by the National Electrical Safety Code (NESC), which I understand is adopted in Kentucky through KRS § 278.042. The bulk transmission system is under the control authority of PJM, a regional transmission organization approved by the Federal Energy Regulatory Commission (FERC). Under PJM's authority, the bulk transmission system is operated in accordance with the reliability standards developed by the North American Electric Reliability Corporation (NERC) and any regional standards developed by ReliabilityFirst Corporation. NERC is the Electric Reliability Organization designated by the FERC under the Federal Power Act of 2005 to develop mandatory and enforceable reliability standards.

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

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

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

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

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

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

Florida. If necessary, Duke Energy Kentucky will contact other utilities for additional line crews, through a mutual assistance program.

Q. HOW DOES DUKE ENERGY KENTUCKY'S AMI DEPLOYMENT IMPACT OUTAGE RESTORATION?

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

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

A. Duke Energy Kentucky maintains its electric delivery infrastructure in accordance with good utility practice by adhering to inspections, monitoring, testing, and periodic maintenance programs. Examples of these existing programs include, but are not limited to, the following: (1) substation inspection program; (2) line inspection program; (3) ground-line inspection and treatment program; (4) vegetation management program; (5) underground cable replacement program; (6) capacitor maintenance program; and (7) dissolved gas analysis in substations. Additionally, Duke Energy Kentucky makes capital investments to maintain reliability. Attachment NJM-1 is a list and description of Duke Energy Kentucky's current Distribution Reliability Programs. Duke Energy Kentucky also uses various reliability indices to measure the effectiveness of its maintenance programs and system reliability.

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

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

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

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

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

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

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

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

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

Today, the Company's system is constructed for one-way power flow in a radial design with limited ability to integrate renewable energy. As time progresses, this system will eventually evolve into a self-optimizing system.

Q. PLEASE BRIEFLY EXPLAIN THE TERM "SELF-OPTIMIZING GRID."

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

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

Presently, the Company is slowly and prudently making these investments over time and in the ordinary course of business as its distribution circuits need upgrading due to age, capacity needs, or changes in performance that dictate such an upgrade is desired. The Company projects a need to upgrade approximately twenty circuits per year as part of normal maintenance and investment. Self-optimizing grid implementation is about 15 percent complete, and at the present deployment rate, a fully self-optimizing distribution grid capability will take about a decade to achieve.

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

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

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

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

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

3) System Average Interruption Frequency Index (SAIFI) is the system average interruption frequency index and represents the average number of interruptions per customer. SAIFI is expressed by the total number of customer interruptions divided by the total number of customers served.

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

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

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

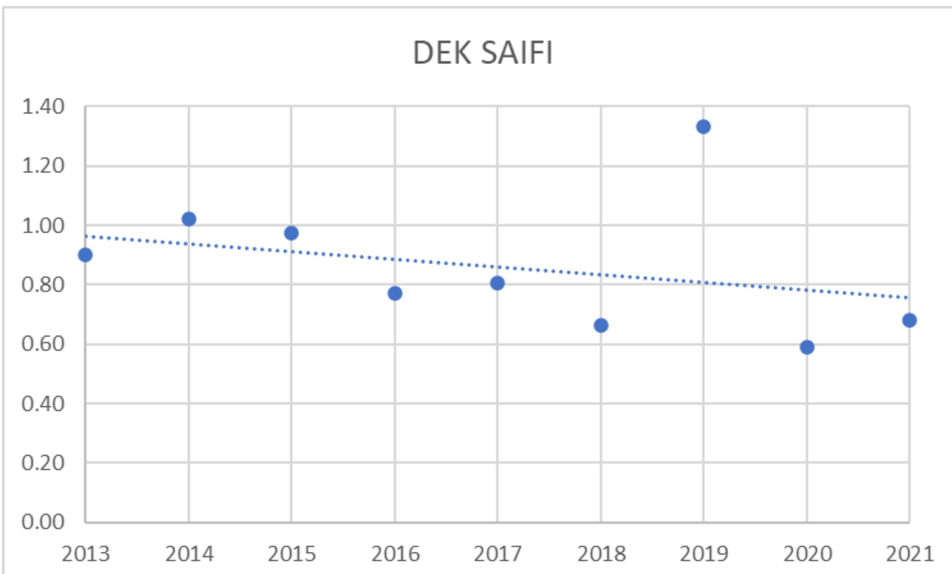
A. Duke Energy Kentucky's system has performed well. Duke Energy Kentucky's reliability scores have exceeded industry average reliability scores and are among the best performing throughout Duke Energy's six state electric service areas. The latest reliability index scores available are for calendar year 2021, and are reported below.

Table 1 – 2021 Reliability Indexes

Reliability Index	Duke Energy KY Actual excl. MED[1]	Duke Energy KY Actual incl. MED
SAIFI	0.68	0.72
SAIDI	63	84

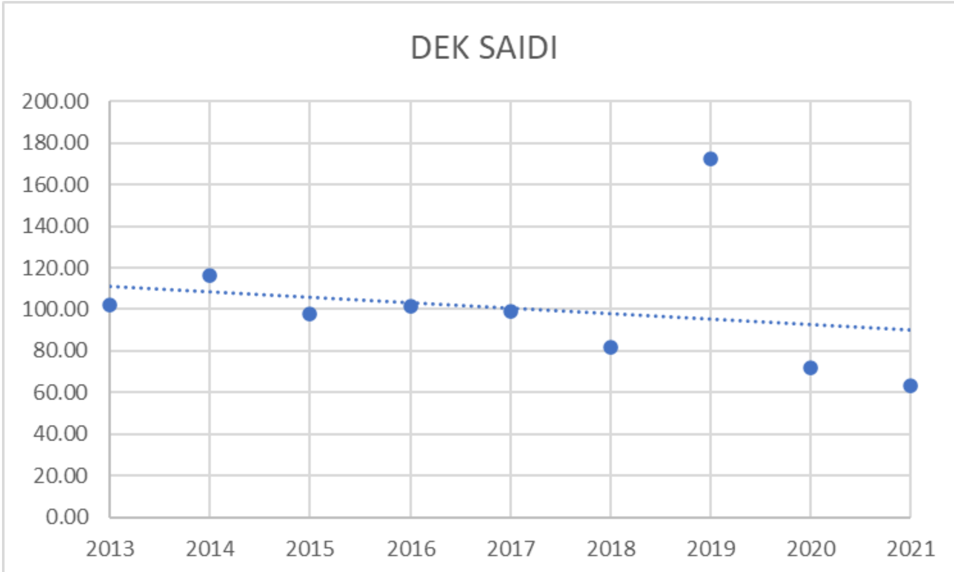
Furthermore, Figures 1 and 2 show a steady trend of improving reliability in Duke Energy Kentucky as measured by SAIFI and SAIDI.

Figure 1 – Duke Energy Kentucky SAIFI



[1] An MED is a major event day.

Figure 2 – Duke Energy Kentucky SAIDI



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

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

A. The table below summarizes Duke Energy Kentucky's capital expenditures for its transmission and distribution facilities for the period from 2015 through March 31, 2024.

Table 2 – Capital Expenditures 2015-2024

$ millions)	2015	2016	2017	2018	2019	2020	2021	2022	2023	Jan-June 2024
Transmission	3.4	1.7	3.4	3.1	12.3	32.9	16.4	8.0	23.6	15.6
Distribution	22.3	23.1	43.6	50.4	66.3	48.3	38.7	43.7	54.5	30.3
Total	**25.7**	**24.8**	**47.0**	**53.5**	**78.6**	**81.2**	**55.1**	**51.7**	**78.1**	**45.9**

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

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

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

Figure 3 – Duke Energy Kentucky Distribution Poles Age Distribution Fall 2022

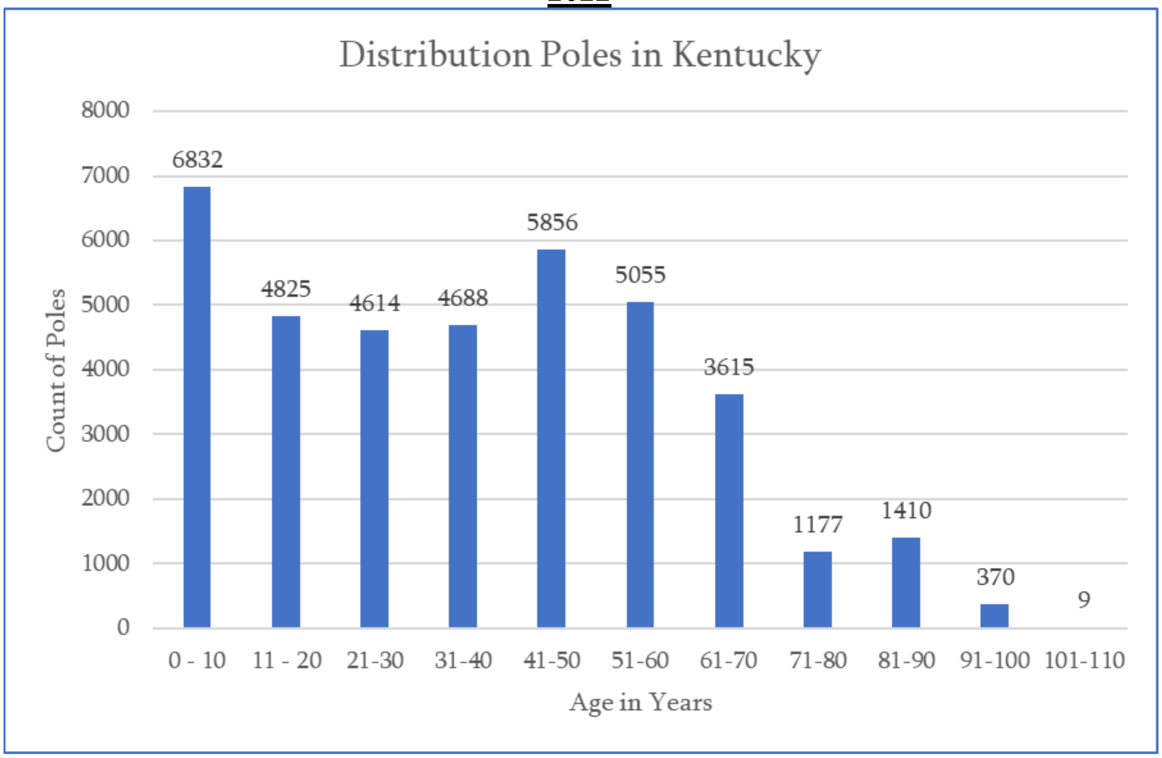
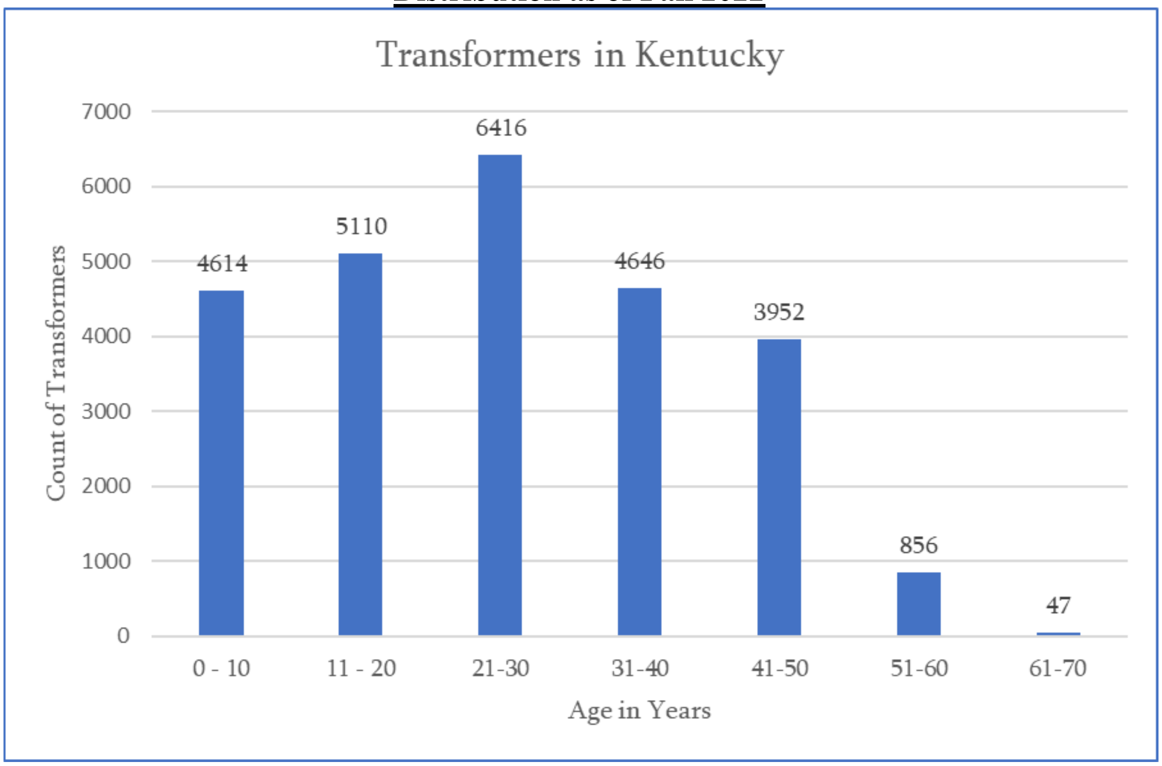


Figure 4 – Duke Energy Kentucky Distribution Transformer Age Distribution as of Fall 2022



Another challenge is increased costs to complete the same amount of work. Factors contributing to this include low unemployment, unprecedented inflation, supply chain constraints, and competition for infrastructure related skilled labor.

Duke Energy Kentucky is also experiencing localized load growth with significant residential and commercial expansion projects as previously discussed.

Q. DO CUSTOMERS' EXPECTATIONS PRESENT A CHALLENGE?

A. Yes. Customers are increasingly using equipment that is highly sensitive to voltage fluctuations; therefore, customers are demanding highly reliable service that minimizes the number of voltage fluctuations. In addition, since the pandemic began, a higher share of customers are working from home with the need for uninterrupted service cited more frequently in customer verbatims. This presents a challenge for Duke Energy Kentucky to strike the correct balance between reliable and economic service.

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

A. Maintaining prior levels of investment and not adapting to incorporate new technology and data will not serve to maintain, let alone enhance reliability or customer satisfaction. Duke Energy Kentucky will need to increase its investments to continue to meet customers' increased expectations. Customer expectations are evolving as technology changes. Customers are requiring a higher degree of reliability, performance, and response. Customers are expecting service restorations to be made more quickly, as so much of their daily life depends upon the availability of electricity. This ranges from the ability to power and charge cellular phones, computers, and other mobile devices, in order to maintain communication access, beyond just heating and cooling homes.

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

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

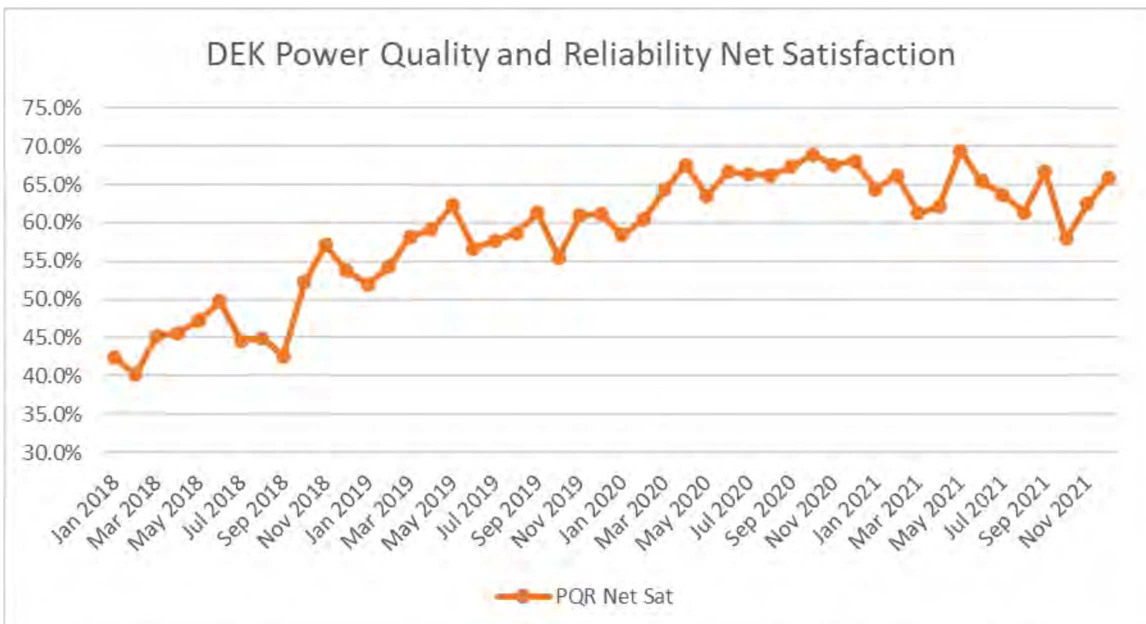
A. Yes. Ms. Spiller explains the Company's initiatives to measure customer satisfaction and its performance through both its internal Customer Experience Monitor (CX Monitor) and Fastrack post-transaction surveys and national benchmark surveys such as J.D. Power. Ms. Spiller further supports the most recent survey data available.

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

A. In 2018, the Company launched the CX Monitor, a randomized, census-based survey administered annually to all residential, small/medium, and large business customers to measure ongoing perceptions of the customer experience. Respondents are asked to provide feedback regarding their overall sentiment as well as satisfaction with key experiences they have had with the Company over the past 12 months. 'Power Quality and Reliability' (PQR) is one of these key experiences. Customers rate their satisfaction on a '0-10' scale while also providing open-end verbatim comments detailing the primary reason(s) for their score. Scores are reported on a 'Net' basis – shown as the share of Promoters (customers providing a score of '9' or '10') minus the share of Detractors (customers providing a score of '0-6').

The CX Monitor survey results indicate that customers care about power reliability. While there are some expected seasonal dips that correspond to summer and spring storms, the CX Monitor survey indicates a 23+ percentage increase between January of 2018 and December of 2021 in customers' net satisfaction with their PQR experience in Kentucky. Figure 5 captures PQR satisfaction overall.

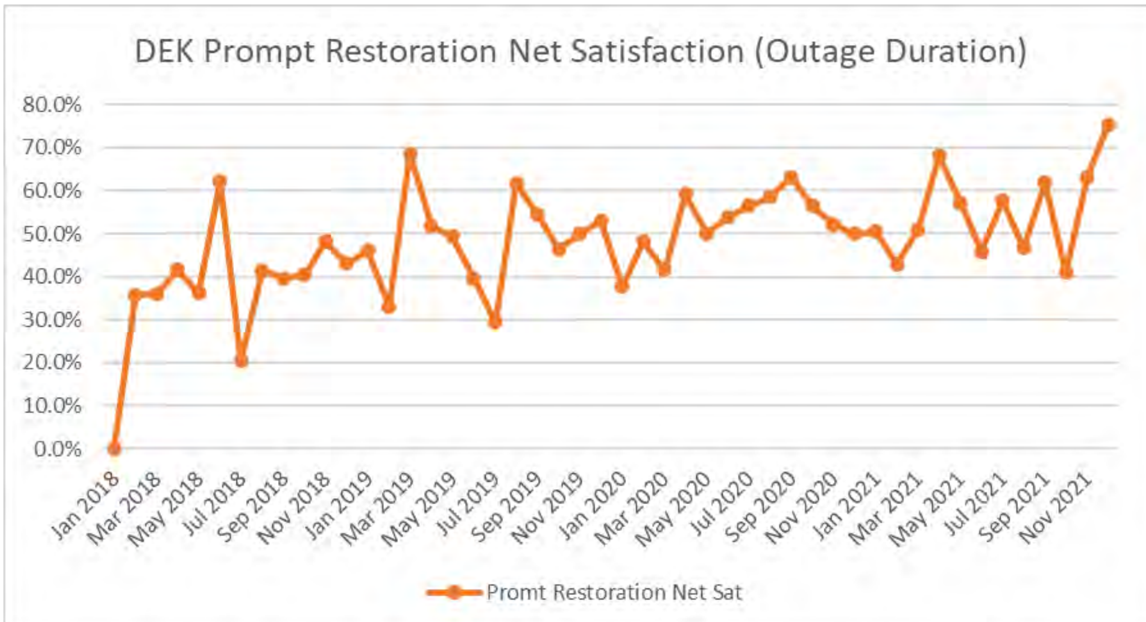
Figure 5 – Duke Energy Kentucky
Power Quality and Reliability Net Satisfaction



Duration of an outage and outage-related communication are also two significant components to PQR satisfaction for Duke Energy Kentucky customers. Both of these areas independently saw improvements, which help explain the overall satisfaction in PQR. Despite expected seasonal dips due to summer and spring storms, customers report an average 39+ percentage net satisfaction increase from February of 2018 through December of 2021 with the duration of prompt restoration of their outage.

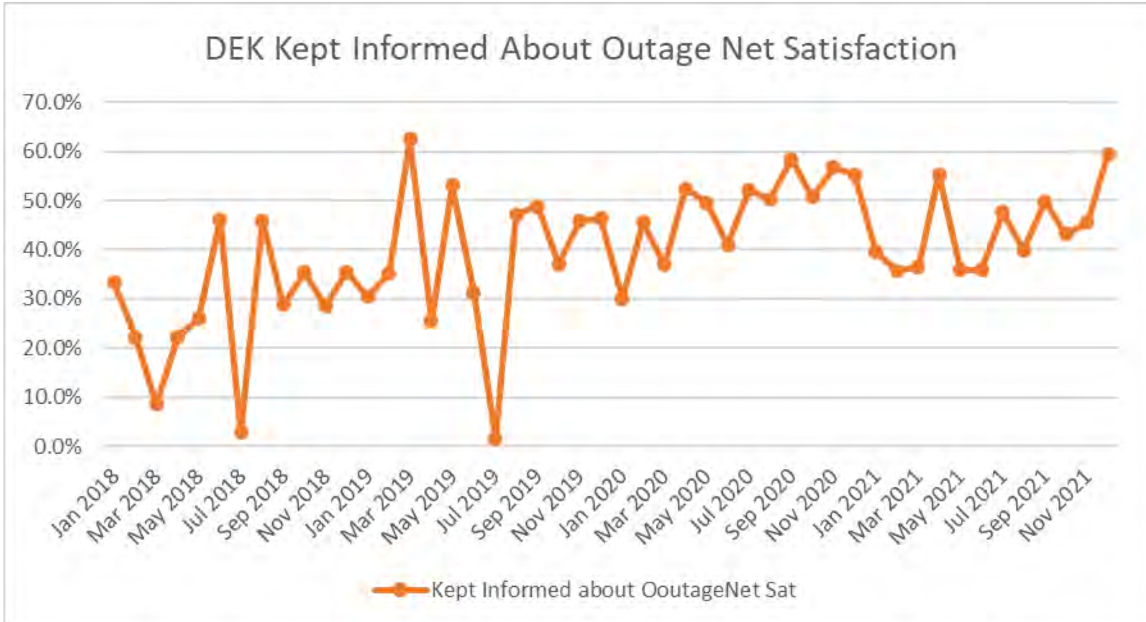
Figure 6 – Duke Energy Kentucky

Prompt Restoration Net Satisfaction



An exciting increase in customer satisfaction comes from customers reporting that they feel better informed about the status of their outage. Duke Energy's Proactive Outage Alerts text SMS communication system, enhanced customer outage maps and improved field updates have all contributed to a 37+ percentage increase between February 2018 and December 2021. These increases offer validation that Duke Energy's investments in highly-satisfying digital channels for customers are yielding significant satisfaction gains.

<u>Figure 7 – Duke Energy Kentucky</u>
<u>Kept Information about Outage Net Satisfaction</u>



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

A. Even though the majority of Duke Energy Kentucky's customers appear to be satisfied with the Company's overall performance, customers have low tolerance for long duration outages and lack of timely outage information. Even though the Company's reliability scores and CX Monitor scores demonstrate the Company is performing well and continuing to make significantly measurable gains in terms of customer net satisfaction, there will always be room for improvement. To that end, while 2022 results will not be final until the end of the year, sentiment has been more volatile in 2022 as customers report frustration with fuel cost pass-through charges driving high utility bills.

Duke Energy Kentucky's customers clearly have high expectations of their utility service. Failure to be proactive to resolve grid reliability issues before they manifest will result in a decline in system performance and customer satisfaction. In order to meet these high expectations, Duke Energy Kentucky must be proactive and take corrective actions before a larger reliability problem manifests itself.

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

A. The deployment of the CX Monitor survey has been a watershed moment for Duke Energy's ability to identify, measure and diagnose customer issues on a monthly basis throughout our Kentucky territory. Duke Energy Kentucky is continually looking for opportunities to enhance and improve its service to customers. Overall increases in Duke Energy Kentucky's PQR, outage duration/prompt restoration and outage communication net satisfaction scores are encouraging and exciting. We believe that continuing to make delivery system investments that will enable the Company to better communicate with customers, have better data regarding their usage, and then monitor and improve the health and performance of the electric delivery system are vital to continuing to improve Duke Energy's core mission of powering the lives of our customers and the vitality of our communities.

Q. PLEASE EXPLAIN HOW THE DELIVERY SYSTEM INVESTMENTS AND RELIABILITY PROGRAMS YOU PREVIOUSLY DESCRIBED ARE INTENDED TO ADDRESS THESE CHALLENGES??

A. Duke Energy Kentucky must adapt its practices and implement new programs to respond to industry demands, changes in technology, and continually evolving customer needs and expectations. Customers' increasing expectations regarding reliability and outage-related communications require increased investment. The delivery system investments and reliability programs described will position the Company to address the challenges of aging infrastructure, localized load growth, and customers' low tolerance for outages and lack of outage-related information by keeping pace with the changes in technology and customer demands.

VI. SCHEDULES AND FILING REQUIREMENTS SPONSORED BY WITNESS

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

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

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

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

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

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

VII. CONCLUSION

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

A. Yes.

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

A. Yes.

VERIFICATION

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

The undersigned, Dominic Melillo, Director Asset Management, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Dominic Melillo Affiant

Subscribed and sworn to before me by Dominic Melillo on this 29TH day of NOVEMBER, 2022.

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

Adele M. Frisch
NOTARY PUBLIC

My Commission Expires: 1/5/2024

Distribution Reliability Programs and Brief Description

Programs	**Description**
Underground Cable Injection Planned	Planned Cable Injection Program
Underground Small Cable Primary-only Replace	Replacement of Underground Cable as a program due to failure rates or testing results. If it is replaced during an outage, it would fall under Restore process. This is for the replacement of primary cable only. Small cable (size 1/0 or smaller), Corrective and Planned.
Underground Large Cable Primary-only Replace	Replacement of Underground Cable as a program due to failure rates or testing results. If it is replaced during an outage, it would fall under Restore process. This is for the replacement of primary cable only. Large cable (size larger than 1/0) Corrective and Planned.
Pole Replace Insp Follow Up	Distribution Poles replaced as part of the Pole Inspection Program only.
Pole Emergency Inspection Based Replace	Replacement of Imminent hazard poles found as part of the Pole Inspection Program. These pole replacements will be field initiated to address any safety concerns associated to aggressively deteriorated poles, as described in the imminent hazard criteria.
Pole Inspection Other Units of Property Follow-up	Replacements of other units of property (UOP) outside a complete pole change out. Part of the Pole Inspection Program only. (E.g. arrestor, cutout)
Pole Reinforcement	Distribution Poles reinforced as part of the Pole Inspection Program only.
Recloser Electronic Replace	Replacement of electronic recloser unit or controller and all capital components
Recloser Hydraulic Replace	Replacement of hydraulic recloser unit and all capital components, including sectionalizers
Cutout Oil to Vacuum Switch Replace	Change out of Oil to Vacuum switches, cutouts, arresters on capacitor banks. Capacitor reactive/corrective work should be charged to the "Capacitor Replace" program.
Over Head Line Switch Replace	Replacement of Over Head line switches, including gang and solid blade disconnects.
Switch Gear Replace	Underground Switchgear Replacement (manually operated). Includes inspection capital follow up, and corrective replacements (PME-style, switching module, etc.). Automatic Throw Over Switch (ATS) replacements identified through inspection should be charged to the ATS Replace program.
Live Front Transformer Replace	Upgrade Live Front Transformers to dead front.
Capacitor Auto	Upgrade of capacitors by adding controls and modem.
Circuit Sectionalization	Installation of sectionalizing devices that are not on the mainline circuit (reclosers, sectionalizers, outdoor vacuum reclosers (OVRs), etc.). Reactive only. Mainline sectionalization devices should be charged to the Circuit Segmentation Program
Over Head Deteriorated Conductor Replace	Replacement of primary conductors that are likely to fail, due to poor performance, condition, or construction method, with a more reliable heavier gauge industry standard wire.
Transformer Retrofit	Retrofitting transformers, replacing Cutouts failed to interrupt and execution of the AB Chance cutout replacement program for efficiency purposes.
Recloser Controller Replacement	Recloser Control Replacement

Switchgear Upgrades-Automation	General Switchgear Inspection Capital Follow-up, which replaces units that failed inspection.
Modem Replace	Proactive program to replace smart device modems (Line Sensor, Reclosers, Regulators, & Capacitors) that are reaching end of useful life
Removal Non-Utilized Infrastructure-Over Head	Removal of Non-Utilized Infrastructure – Over Head
DTUG Emergency Replace	Emergency DTUG Corrective Replacements - Imminent/ Emergency work requiring immediate response. "An DTUG emergency is a situation in which a field performer cannot leave the site until the identified hazard is mitigated and resolved. An emergency would be a situation identified to be a danger to the public, to utility personnel, imminent outage, or to prevent an impact on the environment. An emergency can be applied to any DTUG asset at any location. Emergency repairs can be mitigated or 'made safe' until a more comprehensive repair or replace is performed. Any additional work performed after the emergency hazard has been mitigated and personnel have left the site is no longer considered emergency work." (i.e. Communication Equipment, MVS, RA Switches, Sump Pump)
Pothead Termination	Pothead termination replacement and capital inspection follow-up
Underground Cable Secondary Service Replace	Underground Cable Replace Secondary / Service
Manhole Lid Retrofit	Manhole Lid Retrofits/Replace for Explosion Mitigation across the system.
Line Patrol Replace	Replacement of capital items identified through the regulatory required line patrol inspection.
SMEI Insp Replace	Replacement of other units of property identified through the Surface Mounted Equipment Inspection (SMEI), except for switchgear and pad transformer replacements. Switchgear replacements identified through the SMEI program should be charged to Switchgear Replace program. Pad Transformers replacements identified through the SMEI program should be charged to one of the following programs: Pad Transformer 1-phase (1PH) Oil Leak Insp Replace FUP; Pad Transformer 3PH Oil Leak Inspection Replace FUP; Pad Transformer 1PH Non Leak Inspection Replace FUP; Pad Transformer 3PH Non Leak Insp Replace FUP; Pedestals are O&M only and should be charged to Underground Repairs (Other Planned)
Limited Access Cross Upgrade	Bringing interstate crossings up to NESC grade B construction.
Line Sensor Replace	Replacement of stand-alone line sensors (IE:toll grade or Cooper) only. Includes the controller if it is separate than the line sensor.
NAN Device Replace	Replacement of neighborhood area network (NAN) devices, which includes Silver Springs, Erickson/Ambient and Cisco Itron devices, such as communication nodes electric only and Cisco Grid Routers. These devices were originally used as a part of AMI but are not limited to communicating metering traffic. Does not include modems and line sensors for reclosers, capacitors, or regulators as they should go to the modem replace or line sensor replace programs
Over Head Replace (Other - Planned)	Overhead Corrective Replacements - Work found in the field that is not part of inspections, outages, or power quality, that can be prioritized or scheduled. Over Head Wire Primary Replacements will be charged to "Over Head Wire Primary Replace" program

Over Head Stolen Conductor Replace	Replacement of stolen overhead conductor, including neutrals that are in service.
Over Head Wire Primary Replace	Replacement of at least one span of Over Head Wire Primary, including neutral
Over Head Wire Secondary Service Replace	Replacement of at least one span of Over Head Wire Secondary, including neutral
Underground Replace (Other - Planned)	Underground Corrective Replacements - Work found in the field that is not part of inspections, outages, or power quality, that can be prioritized or scheduled.
Pole Stub Removal	Stub Pole Removal (Planned). This is a removal project only. It is only to be used for pulling of poles that are a part of the Pulled Pole backlog or the project that the pole removal has already been closed.
Pole Replacement (Non- Insp Based)	Replacement Distribution Poles typically "found in field" by operations or engineering and not associated with an outage, public damage, or pole inspection. This includes Poles identified as part of the 360 poles inspection that are not the direct or adjacent poles. These poles must be referred as a service request to be reviewed and prioritized by a program owner. Poles found while performing other capital work must be included in the scope of the original capital project, unless the pole was not the direct or adjacent pole found in the original 360 pole inspection. Includes pole replacements part of new service work to provide service to new customers. Includes all emergency and non-emergency pole replacements found in field. Emergency (Imminent) corrective pole replacements associated with an inspection program will roll up to 'Pole Emergency Inspection Based Replace'.
Over Head Transf Replace	Overhead corrective transformer replacements found in the field that is not part of inspections, outages, or power quality, that can be prioritized or scheduled.
Pad Transformer 1PH Non-Leak Replace	Padmount Transformer single phase non-leak replacement, includes inspection follow up and corrective.
Pad Transformer 1PH Oil Leak Replace	Padmount Transformer single-phase replacement resulting from oil leak, includes inspection follow up and corrective.
Pad Transformer 3PH Non-Leak Replace	Padmount Transformer three-phase non- leak replacement, includes inspection follow up and corrective.
Pad Transf 3PH Oil Leak Replace	Padmount Transformer three-phase replacement resulting from oil leak, includes inspection follow up and corrective.
Capacitor Replace	Change out of entire capacitor bank or individual components including controller, cutouts, arrestors, or switches not identified as part of the Oil-to-Vacuum switch replacement program. New installs will be charged to New Capacitor Installation program
Regulator Replace	Change out of entire regulator bank or individual components including controller, cutouts, arrestors or switches not identified as part of the Oil-to-Vacuum switch replacement program. New installs will be charged to New Regulator Installation program.
Declared Protection Zone	Proactive solution to a chronic problem, by identifying and improving a section of a feeder. Done when all other reliability efforts are not successful. Driven by internal analysis of performance.

Over Head Outage Investigation Improve Replace	Over Head outage investigation and replacements identified by Reliability Engineering through Common Reliability Standard. May also include issue reported by Customers, Commission, or daily outage reports. Corrective action should be identified and corrected within a pre-determined amount of time.
Underground Outage Investigation Improve Replace	Underground Outage Investigation and replacements identified by Reliability Engineering through Common Reliability Standard. May also include issue reported by Customers, Commission, or daily outage reports. Corrective action should be identified and corrected within a pre-determined amount of time.
Proactive Pad Transf 1PH Non- Leak Replace	Proactive single phase dry Transformer replacement, within 100 feet of active waterway (not a retention pond; active flowing waterway), and greater than 210 gallons of oil.
Proactive Pad Transf 1PH Oil Leak Replace	Proactive Padmount Transformer single-phase replacement resulting from oil leak, within 100 feet of active waterway (not a retention pond; active flowing waterway), and greater than 210 gallons of oil.
Proactive Pad Transf 3PH Non- Leak Replace	Proactive Padmount Transformer three-phase non- leak replacement, within 100 feet of active waterway (not a retention pond; active flowing waterway), and greater than 210 gallons of oil.
Proactive Pad Transf 3PH Oil Leak Replace	Proactive Padmount Transformer three-phase replacement resulting from oil leak, within 100 feet of active waterway (not a retention pond; active flowing waterway), and greater than 210 gallons of oil.
Underground Cable Loop Closeout	Install additional cable on radial Underground Residential (URD) to create loop that allows back feed of the URD
Oil Minder Sensor Replace	Install or Replace sump pump with oil stop valve or oil minder sensor in network vaults with drains
Circuit Connectivity	Projects Driven by Distribution Capacity needs outside the substation and not associated with a substation upgrade.
Segmentation & Automation	Smart Grid Self-Healing
Live Front Switchgear	Upgrade Live Front to Dead Front
Substation Capacity	Load Growth, Load Transfers and Tie Lines for Distribution
Targeted Over Head Under Ground-	Replace Existing Over Head Distribution System with Under Ground Facilities on a targeted basis.
Circuit Capacity	Upgrade D-lines or addition of new circuit driven by the addition of a new retail substation to serve load growth.