COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF DUKE	**)**	
ENERGY KENTUCKY, INC. FOR: 1) AN	**)**	
ADJUSTMENT OF THE ELECTRIC RATES;	**)**	
2) APPROVAL OF NEW TARIFFS;	**)**	**CASE NO. 2019-00271**
3) APPROVAL OF ACCOUNTING PRACTICES	**)**	
TO ESTABLISH REGULATORY ASSETS AND	**)**	
LIABILITIES; AND 4) ALL OTHER	**)**	
REQUIRED APPROVALS AND RELIEF	**)**	

DIRECT TESTIMONY

AND EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2019

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

A. My name is Lane Kollen. My business address is J. Kennedy and Associates, Inc. ("Kennedy and Associates"), 570 Colonial Park Drive, Suite 305, Roswell, Georgia 30075.

Q. What is your occupation and by whom are you employed?

A. I am a utility rate and planning consultant holding the position of Vice President and Principal with the firm of Kennedy and Associates.

Q. Describe your education and professional experience.

A. I earned a Bachelor of Business Administration ("BBA") degree in accounting and a Master of Business Administration ("MBA") degree from the University of Toledo. I also earned a Master of Arts ("MA") degree in theology from Luther Rice University. I am a Certified Public Accountant ("CPA"), with a practice license, Certified Management Accountant ("CMA"), and Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than thirty years, initially as an employee of The Toledo Edison Company from 1976 to 1983 and thereafter as a consultant in the industry since 1983. I have testified as an expert witness on planning, ratemaking, accounting, finance, and tax issues in proceedings before regulatory commissions and courts at the federal and state levels on hundreds of occasions.

I have testified before the Kentucky Public Service Commission on numerous occasions, including base rate (electric, gas, and water), environmental surcharge, fuel adjustment clause, resource acquisition, and merger and acquisition proceedings involving Duke Energy Kentucky, Inc. ("Company" or "DEK"), Kentucky Power Company ("KPC"), Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), East Kentucky Power Cooperative, Inc. ("EKPC"), Big Rivers

Electric Corporation ("BREC"), Atmos Energy Corporation ("Atmos"), Columbia Gas of Kentucky, Inc., and Kentucky-American Water Company ("KAW").[1]

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG").

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) summarize the AG rate increase recommendations, 2) address numerous issues that affect the Company's revenue requirement, including charges from Duke Energy Business Services ("DEBS"), 3) and quantify the effect on the revenue requirement of the return on equity recommendation provided by AG witness Mr. Richard Baudino.

Q. Please summarize your testimony.

A. I recommend that the Commission increase the Company's base revenues by no more than $26.198 million, a reduction of at least $19.436 million to the Company's proposed base rate increase of $45.634 million. In addition, I recommend a one-time refund of DEBS excess accumulated deferred income taxes ("EDIT") of $0.215

[1] My qualifications and regulatory appearances are further detailed in my Exhibit___(LK-1).

million. In the following table, I provide a list of the AG recommendations and the effect of each recommendation on the Company's requested increase.[2] The AG recommendations regarding the cost of capital also will reduce the proposed Environmental Surcharge Mechanism ("ESM") rider, although I do not show the quantification of these reductions in the table.

[2] The calculations of the amounts shown on the table and cited throughout my testimony are detailed in my electronic workpapers, which are filed contemporaneously with my testimony.

Duke Energy Kentucky, Inc.
Case No. 2019-00271
Base Revenue Requirement
Summary of AG Recommendations
For the Test Year Ended March 31, 2021
($ Millions)

	Amount Before Gross-Up	KPSC Maint. Fee Gross-up	Amount After Gross-Up
Base Rate Increase Requested by Company			45 634
Effects on Base Rate Increase of AG Rate Base Recommendations			
Remove Asset ADIT for Solar ITC			(0 250)
Reduce Fuel and Materials and Supplies Inventories For Amounts Financed By Vendors			(0 187)
Reflect Cash Working Capital to Zero In Lieu of 1/8th O&M Methodology			(1 242)
Remove Regulatory Asset for Deferred Rate Case Expenses			(0 059)
Reflect Changes in Accumulated Depreciation and ADIT Due to Lower Depreciation Expense			0 155
Effects on Base Rate Increase of AG Operating Income Recommendations			
Reduce Payroll Expense	(1 125)	1 00196	(1 127)
Reduce Payroll Taxes Associated with Reduction in Payroll Expense	(0 086)	1 00196	(0 086)
Defer Customer Connect Development Implementation Expenses	(0 909)	1 00196	(0 911)
Eliminate Credit/Debit Card Convenience Fees	(0 493)	1 00196	(0 494)
Remove SERP Costs	(0 122)	1 00196	(0 122)
Reduce Payroll Taxes Associated with Reduction in Short Term Incentive Compensation	(0 065)	1 00196	(0 066)
Reflect 5 Year Amortization of FERC Order No 494 RTEP Refunds	(1 600)	1 00196	(1 603)
Reduce Excessive Cost of Capital Included in DEBS Expenses	(0 678)	1 00196	(0 679)
Reject Increase to Depreciation Expense Due to Changes in Depreciation Rates	(7 431)	1 00196	(7 446)
Remove Amortization of Rate Case Expenses for New Depreciation Study	(0 012)	1 00196	(0 012)
Effects on Base Rate Increase of AG Rate of Return Recommendations			
Reduce Long Term Debt Rate			(0 056)
Reduce Return on Equity from 9 8% to 9 0%			(4 761)
Remove Revenue Requirement Effects of New Battery Storage Project			(0 346)
Remove Revenue Requirement Effects of Electric Vehicle Charging Pilot Program			(0 145)
Total AG Adjustments to DEK Request			(19 436)
Maximum Base Rate Increase After AG Adjustments			26 198
Reflect One-Time Refund of DEBS Excess ADIT	(0 214)	1 00196	(0 215)
Maximum Overall Increase in Rates After AG Adjustments			25 984

The remainder of my testimony is structured to address each of the issues on the preceding table. The amounts that I cite throughout my testimony are electric only unless otherwise indicated as "total Company."

II. RATE BASE ISSUES

A. Accumulated Deferred Income Taxes

Q. Describe the accumulated deferred income tax (“ADIT”) balances that the Company subtracted from rate base.

A. As a first step, the Company forecast the per books ADIT balances by account and temporary difference, including the effects of plant additions through the end of the test year.[3] In the next step, the Company removed certain of those ADIT balances from the rate base calculations.[4] In general, the Company removed those ADIT balances where the corresponding temporary difference was not included in rate base or the related expense was not included in operating income.

Q. Do you generally agree with the Company’s removal of certain of the ADIT balances from the rate base calculations?

A. Yes. However, the Company incorrectly failed to remove the Other Noncurrent After-Tax DTA for Solar ITC from the rate base calculation. The DTA acronym refers to “deferred tax asset.” A DTA is an asset ADIT amount generally recorded in account 190. If properly included for ratemaking purposes, a DTA is added to rate base, while

[3] Response to AG-DR-01-014. I have attached a copy of that response as my Exhibit___(LK-2).
[4] Response to STAFF-DR-02-009(b). I have attached a copy of that response as my Exhibit___(LK-3).

the underlying temporary difference is subtracted from rate base.

Q. Does the Company now agree that the Other Noncurrent After-Tax DTA for Solar ITC should be removed from the rate base calculation?

A. Yes.[5]

Q. What are the effects of removing the Other Noncurrent After-Tax DTA for Solar ITC from the rate base calculation and the revenue requirement?

A. The effects are a $3.017 million reduction in rate base and a $0.250 million reduction in the revenue requirement.

B. Fuel Inventories and Materials and Supplies Inventories

1. Vendor Financing of Fuel Inventories and Materials and Supplies Inventories

Q. Describe the Company's request for fuel inventories and materials and supplies inventories in rate base.

A. The Company included $19.518 million in fuel inventories and $18.759 million in materials and supplies ("M&S") inventories in rate base.[6]

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[5] Response to AG-DR-02-005. I have attached a copy of that response as my Exhibit___(LK-4).
[6] Schedule B-5.

Q. Did the Company offset the fuel inventories and M&S inventories with the related accounts payables?

A. No. A portion of the fuel and M&S inventories is financed by the Company's vendors, not its investors and/or customers. The portions of these inventories financed by the Company's vendors are reflected in the related accounts payables.

Q. What is the significance of the fact that a portion of the fuel inventories and M&S inventories is financed by the Company's vendors?

A. The Company is not entitled to include in rate base or earn a return on costs that it did not finance. In prior cases, the fact that a portion of these inventories was financed by the Company's vendors was implicitly recognized in the lower capitalization used for the *return on* component of the revenue requirement.

With the transition to rate base in lieu of capitalization, there no longer is an implicit recognition of this vendor financing. Consequently, the Commission now must make explicit adjustments to remove the portions of the fuel and M&S inventories from rate base that are financed by the Company's vendors.

Q. What is your recommendation?

A. I recommend that the Commission reduce rate base for the accounts payables related to the fuel inventories and M&S inventories.

Q. What are the effects of your recommendations?

A. The effect is a $2.258 million reduction in rate base related to the fuel inventories accounts payable.[7] This adjustment results in a $0.187 million reduction in the revenue requirement. I have not reflected a reduction in rate base related to the M&S inventories accounts payable because the Company could not quantify the M&S inventories accounts payable in response to AG discovery.[8]

2. Customer Financing of Materials and Supplies Inventories

Q. Has the Company reduced rate base for the customer financing of M&S inventories?

A. No. The Company has included cash working capital based on one-eighth of the non-fuel O&M expense. The O&M expense includes materials and supplies expense. The Company's cash working capital includes one-eighth of this materials and supplies expense in rate base. In effect, the Company has included M&S inventories in rate base as a separate component of rate base without an offset for the M&S inventories that also are included in cash working capital in rate base.

[7] Response to AG-DR-02-021. I have attached a copy of that response as my Exhibit___(LK-5).
[8] Response to AG-DR-02-022. I have attached a copy of that response as my Exhibit___(LK-6).

Q. Is that appropriate?

A. No. The Company should earn a return on M&S inventories only to the extent that they are not financed by its vendors or by its customers in another component of rate base in the revenue requirement formula. Again, this was not an issue in prior cases when the *return on* component of the revenue requirement was based on capitalization, not rate base. In those prior cases, the capitalization implicitly reflected only the amount the Company's investors financed, which was less due to the fact that a portion of the M&S inventories was financed by its vendors. The capitalization also reflected only the M&S inventories, not an additional amount for one eighth of the M&S expense included in cash working capital. Now that the *return on* is based on rate base and not capitalization, the Commission needs to explicitly and specifically address these "overlap" issues to ensure that the Company does not earn a second return on the same M&S inventories.

Q. What is the effect of your recommendation to reduce rate base for the M&S inventories customer financing?

A. There is no effect if the Commission adopts my recommendation to set the cash working capital at $0, which I address in the next section of my testimony. Alternatively, if the Commission does not adopt my recommendation regarding cash working capital, then I recommend that the Commission reduce the M&S inventories remaining after reduction for the Company's vendor financing to $0. The effect of this reduction in rate base is a $1.478 million reduction in the revenue requirement.

C. <u>Cash Working Capital</u>

Q. Describe the Company's calculation of cash working capital included in rate base.

A. The Company included $14.965 million in cash working capital in rate base.[9] It calculated cash working capital using one-eighth of its forecast non-fuel O&M expense.[10]

Q. Is the use of the one-eighth of non-fuel O&M expense an appropriate approach?

A. No. The lead/lag approach is a superior and far more accurate approach. The lead/lag approach measures the number of lag days in revenue cash receipts and the number of lag days in expense cash disbursements and weights the daily revenue and expense amounts using the lag days to calculate the net investor (positive) or customer (negative) cash working capital investment.

In contrast to the lead/lag approach, the one-eighth of non-fuel O&M expense approach is outdated. It results in a hypothetical cash working capital that is inaccurate and tends to be greatly overstated. The one-eighth of non-fuel O&M expense approach

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[9] Schedule B-5.
[10] WPB-5.1a.

fails to measure, let alone accurately measure, the revenue lag days or the expense lag days for various components. The one-eighth of non-fuel O&M expense approach is based on the simplistic and demonstrably incorrect assumption that investors provide and finance cash working capital equal to one-eighth of the utility's non-fuel O&M expense.

The one-eighth non-fuel O&M expense approach assumes that there is no difference in the cash working capital between those utilities that sell their receivables to a third party and those that do not. Yet, there obviously is a significant difference in the utilities' actual cash working capital investment between the utility that sells and converts its receivables to cash every day compared to the utility that waits 30-40 days to receive payments from its customers and convert its receivables to cash.

To illustrate the different results between two utilities, only one of which sells its receivables, under the one-eighth of non-fuel O&M expense approach and the lead/lag approach, consider the following example. The daily non-fuel revenues for each utility are $10 million, or $3,650 million annually. The first utility sells its receivables every day. Its revenue lag is 1 day. The second utility does not sell its receivables. Its revenue lag is 35 days. The daily cash non-fuel O&M expenses for each utility are $6 million, or $2,190 million annually, and the non-cash expenses for each utility are $4 million, or $1,460 million. The expense lag on cash expenses is 22 days and on non-cash expenses is 0 days.

Under the one-eighth of non-fuel O&M expense approach, each utility would include $273.8 million (1/8 * $2,190 million in non-fuel O&M expense) in cash working capital. Under the lead/lag approach, the first utility would include *negative* $122 million ((1 day revenue lag - 22 days expense lag) * $6 million daily cash expenses + (1 day revenue lag - 0 days expense lag) * $4 million daily non-cash expenses) in cash working capital. Under the lead/lag approach, the second utility would include $218 million ((35 days revenue lag – 22 days expense lag) * $6 million daily cash expenses + (35 days revenue lag – 0 days expense lag) * $4 million daily non-cash expenses) in cash working capital.

The one-eighth of non-fuel O&M expense overstates the cash working capital for both utilities compared to the lead/lag approach, but overstates it significantly more for the first utility that sells its receivables compared to the second utility that does not sell its receivables.

Q. Is the use of the one-eighth of non-fuel O&M expense approach or the lead/lag approach a case of first impression in this proceeding for Duke Energy Kentucky?

A. Yes. This is a case of first impression on cash working capital included in rate base in the calculation of the revenue requirement for DEK. In prior electric rate cases, DEK calculated the *return on* component of the revenue requirement based on capitalization, not on rate base. Although DEK provided a reconciliation of capitalization to rate base in prior electric rate cases, which included cash working capital calculated using the one-eighth of non-fuel O&M expense approach, DEK's revenue requirement was not determined using rate base and the calculation of cash working capital using the one-eighth approach did not affect the revenue requirement.

In its most recent gas rate case, DEK transitioned to rate base from capitalization.[11] In that case, DEK included cash working capital in rate base using the one-eighth of non-gas O&M expense approach. The AG opposed this methodology and recommended that the Commission set cash working capital at $0. The case was settled. The Commission neither affirmed nor rejected the use of the one-eighth approach, although the settlement reflected the one-eighth approach solely for the purpose of settling that case.

Q. Has the Commission recently adopted or affirmed the lead/lag approach for other utilities that use rate base instead of capitalization?

A. Yes. The Commission recently adopted the lead/lag approach in lieu of the one-eighth of O&M expense approach in an Atmos Energy Corporation base rate proceeding. In its Order in that proceeding, the Commission stated the following:

> The Commission finds that the cash working capital allowance included in Atmos's rate base should be based upon the lead/lag study as filed . . . Atmos's lead/lag study . . . more accurately reflects the working capital needs of Atmos.[12]

[11] Case No. 2018-00261.
[12] Order, Case No. 2017-00349 at 16-17 (Ky. Commission May 3, 2018).

Similarly, the Commission recently adopted the lead/lag approach for cash working capital in a Kentucky-American Water Company base rate proceeding.[13] KAW proposed the lead/lag approach in its filing in that proceeding and no party opposed the use of the lead/lag approach or argued for the one-eighth approach or that the one-eighth approach was superior to the lead/lag approach.

Q. How does the Company's request in this proceeding compare to recent requests by Duke Energy Ohio, Inc. ("DEO") before the Public Utilities Commission of Ohio ("PUCO") and Duke Energy Indiana, LLC ("DEI") before the Indiana Utility Regulatory Commission ("IURC")?

A. DEO is the parent company of DEK and it historically has included $0 in cash working capital in rate base in lieu of the negative cash working capital that would result from the lead/lag approach, including its most recent case.[14]

DEI is an affiliate of DEK and it historically has included $0 in cash working capital in rate base in lieu of the negative cash working capital that would result from the lead/lag approach, including its pending case.[15]

Q. What is the single largest factor that affects the cash working capital in the

[13] Order, Case No. 2018-0358 at 3-8 (Ky. Commission June 27, 2019).
[14] Response to AG-DR-02-029. I have attached a copy of that response as my Exhibit___(LK-7).
[15] Response to AG-DR-02-030. I have attached a copy of that response as my Exhibit___(LK-8).

lead/lag approach for DEK, DEO, and DEI?

A. The single largest factor is that all three utilities accelerate the conversion of their receivables into cash and at minimal cost by selling the receivables to their affiliate Cinergy Receivables, L.L.C. ("Cinergy Receivables").[16] Unlike other utilities that do not sell their receivables, the sales substantially accelerate the conversion of their receivables into cash and significantly reduce the revenue lag (the number of days between the meter reads and receipt of customer payments) compared to other utilities that must finance their receivables for 30 or more days until they receive payment.

Q. What are the actual DEK revenue lag days?

A. The DEK revenue lag days are [redacted] days. DEK sells the [redacted] receivables [redacted] to Cinergy Receivables.[17]

Q. What are the typical utility revenue lag days for those utilities that do not sell their receivables?

A. In my experience, the typical utility revenue lag days is 30 to 40 days for those utilities

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[16] Cinergy Receivables is an affiliated special purpose entity created to accelerate the conversion of receivables into cash and to reduce the cost of financing customer receivables.

[17] Response to AG-DR-02-024, Confidential Attachment 1, a copy of the Purchase and Sale Agreement between DEK and Cinergy Receivables, which states: [redacted]

that do not sell their receivables.

Q. If the revenue lag is substantially reduced, what effect does that have on cash working capital calculated using the lead/lag approach?

A. It means that the revenue lag is less than the expense lag for all cash and non-cash expenses, except those that involve prepayments. On a net basis, it means that cash working capital is negative.

Q. Have you sought the data necessary to calculate cash working capital using the lead/lag approach?

A. Yes. However, the Company refuses to provide it, claiming that the Commission historically has relied on the one-eighth of non-fuel O&M expense approach. Of course, as I previously noted, the Commission has not used rate base in prior DEK electric base rate cases for the *return on* component of the revenue requirement calculation.

Q. What are your recommendations?

A. I recommend that the Commission set cash working capital at $0. This is an informed and reasonable result that nevertheless still overstates the cash working capital using the lead/lag approach, especially due to the extremely low revenue lag days. It is consistent with the DEO filings before the PUCO and the DEI filings before the IURC.

The one-eighth of non-fuel O&M expense approach is outdated and fails to correctly measure the Company's actual revenue and expense lag days to accurately calculate the cash working capital investment made by either investors or customers on a net basis.

I also recommend that the Commission direct the Company to perform and file a cash working capital study using the lead/lag approach in both its next electric and gas base rate case proceedings.

D. <u>Regulatory Asset for Deferred Rate Case Expenses</u>

Q. Describe the Company's request to include a regulatory asset for deferred rate case expenses in rate base.

A. The Company included $0.949 million as a regulatory asset for the forecast rate case expenses in this proceeding and unamortized rate case expenses in prior electric rate case proceedings.[18] The Company proposes a five-year amortization period.

The forecast rate case expenses for this case include $0.060 million for the Company's depreciation study.[19] In the Operating Income section of my testimony, I conclude that the Company's decision to seek increases in its depreciation rates was unduly aggressive and that the study was unnecessary given that the present

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[18] Schedule F-6, WPF-6a.
[19] Schedule F-6.

depreciation rates were approved only two years ago.

Q. Did DEI include the regulatory asset for its deferred rate case expenses in rate base in the pending rate case proceeding before the Indiana Utility Regulatory Commission?

A. No.

Q. Should the Commission include DEK's regulatory asset for its deferred rate case expenses in rate base in this proceeding?

A. No. The rate case expenses were and will be incurred to benefit Duke Energy, the parent company of DEK, and its shareholders. They were and will not be incurred to benefit DEK's customers.

Q. What are your recommendations?

A. I recommend that the Commission allocate the *return on* the regulatory asset for the deferred rate case expenses to DEK and Duke Energy shareholders, but allocate the amortization expense to DEK's customers as a form of sharing between Duke Energy shareholders and DEK's customers. Over five years, this will allocate approximately 15% of the total revenue requirement to Duke Energy and approximately 85% to DEK's customers.

I also recommend that the Commission disallow the cost of the depreciation study. The Company was unduly aggressive in seeking significant increases in its depreciation rates and depreciation expense only two years after the Commission approved the present depreciation rates.

Q. Is there another reason to allocate the return on the regulatory asset for rate case expense to Duke Energy shareholders and the amortization expense to DEK customers?

A. Yes. The revenue requirement declines each year as the regulatory asset is amortized and the rate base amount declines. However, DEK's customers never benefit from this cost reduction until base rates are reset at some future date because the revenue recovery set in this rate case continues at the same amount regardless of the decline in the rate base and never is trued-up. In addition, if DEK's base rates are not reset within the next five years, then it will continue to recover the amortization expense even though the regulatory asset is fully amortized. Again, DEK's customers never benefit from these cost reductions because the revenue recovery is never trued-up.

Q. What are the effects of your recommendations to exclude the Company's regulatory asset for deferred rate case expenses from rate base and remove the cost of the deprecation study from amortization expense?

A. The effects are a $0.059 million reduction in the revenue requirement to remove the return on the rate base amount and another $0.012 million to remove the amortization expense for the cost of the depreciation study.

III. OPERATING INCOME ISSUES

A. <u>Duke Energy Kentucky and Duke Energy Business Services Payroll Expense and Related Payroll Tax Expense</u>

Q. Describe how the Company forecasts payroll and related payroll tax expense in the test year, including both DEK and DEBS.

A. The Company's budget/forecast methodology varies significantly and is not uniform throughout DEK or DEBS. Unlike other utilities that file forecast test years in rate cases before the Commission, the Company does not rely on actual payroll costs or actual or forecast full-time equivalent employee ("FTE") headcounts or the actual or expected hourly pay or salaries for these FTEs. Nor does the Company's forecast methodology clearly distinguish between employees and contractors, also referred to by DEK as "contingent" employees.

The Company provided this description of its payroll budgeting process in response to AG discovery.

> Payroll costs are budgeted using various methods that are at the discretion of the departments. Examples include (1) using average labor costs realized in actuals and escalated for merit/promotions per the budget guidelines; (2) using a unit cost estimate where the department has an estimate of the average costs to perform various tasks (example – installing customer meters or pole replacements) and an estimate of how many of those units they expect to complete in the budget period; (3) using an estimated headcount and expected

salary.[20]

Q. What is the significance of this hodge-podge of budget/forecast methodologies?

A. It makes it very difficult to assess the Company's forecasts for payroll costs in the test year for reasonableness based on the inconsistent methodologies that it employed. For example, the Company's claims that it does not budget FTEs. Yet, it would appear to be intuitively difficult, if not impossible, for DEK to accurately forecast payroll costs without knowing the number of FTEs and their hourly wage rates or annual salaries.

In fact, the Company could not explain increases in the test year in payroll costs based on the number of FTEs and it had difficulty in responding to discovery for detail and comparisons of such costs due to different sources for the data. For example, the Company provided comparative payroll cost data in response to AG discovery that indicated significant reductions in DEK FTEs in January 2019, only to rebound by July 2019.[21] The data provided in that response also indicated an increase of 33% in payroll costs in the test year compared to the monthly average of actual 2019 payroll costs and 13% compared to budget 2019 payroll costs. In response to subsequent AG discovery, the Company revised certain of the payroll information provided in response to the prior discovery. Even after the corrections to the initial responses to

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[20] Response to AG-DR-2-37(a).

[21] Response to AG-DR-01-042, Attachment 1. I have attached a copy of that response and Attachment 1 without the supporting workpapers as my Exhibit___(LK-9). Thus, only 5 pages of the Attachment 1 is included.

AG-DR-01-042, the Company still forecasts an increase in payroll costs in 2020 of 9% compared to the actual payroll costs in 2019.[22]

It is even more difficult, if not impossible, for the Commission to review the details of any such forecast. It therefore requires the Commission to assess the forecast in the aggregate from the top down in comparison to recent actual costs rather than simply assume that the Company's budget/forecast is reasonable.

Q. How does the Company's forecast payroll cost for the test year compare to its actual payroll cost for 2019?

A. It is excessive, even when the Company's forecast 3.5% increase for merit and promotion pay increases is applied. More specifically, the Company's actual monthly payroll expense (the component of payroll costs included in operating expenses) in 2019 is $2.058 million. In comparison, the Company forecasts monthly payroll expense of $2.247 million ($26.964 total in the test year). This represents an increase of 9.2%, well in excess of the maximum 3.5%, well in excess of the 1% to 3% range for union FTEs cited by Mr. Jacobi,[23] and well in excess of the 2.5% increase effective on April 1, 2020 for the Utility Workers of America and the 3.0% increase effective

[22] Response to AG-DR-02-039 including Attachment. I have attached a copy of that response and the Attachment without the supporting workpapers as my Exhibit___(LK-10). Thus, only 4 pages of the Attachment is included.

[23] Direct Testimony of Mr. Christopher Jacobi at 21.

for the International Brotherhood of Electrical Workers effective on April 1, 2020.[24] The wages for the employees represented by the two unions comprise 90% of the DEK payroll cost.[25]

Q. What is your recommendation?

A. I recommend that the Commission use the most recent actual monthly payroll expense and escalate it by 3.0% annually for the test year. This assumes no change in the average FTEs, which is consistent with the "current company guidance to maintain a flat headcount."[26]

Q. What is the effect of your recommendation?

A. The effect is a $1.125 million reduction in payroll expense and a $1.127 million reduction in the revenue requirement. There would be another $0.086 reduction in payroll taxes expense and the revenue requirement related to the reduction in payroll expense.

B. <u>Customer Connect Development and Implementation Operation and Maintenance Expense</u>

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[24] Direct Testimony of Renee Metzler at 16-17.
[25] Public response to STAFF-DR-01-041.
[26] Response to AG-DR-02-039. I have attached a copy of that response as my Exhibit___(LK-10).

Q. Describe the Company's request to include Customer Connect development and implementation expenses in the revenue requirement.

A. The Company seeks recovery of $0.908 million in O&M expense for Customer Connect development and implementation in the revenue requirement.[27] The Customer Connect program is a new customer information system ("CIS") platform expected to be fully operational in Fall 2022.[28] The Company claims that the Customer Connect platform will provide additional functionality, achieve economies due to the use of a single CIS for all Duke Energy regulated utilities, and avoid downtime experienced with the existing CIS.[29]

In addition to the requested O&M expense for Customer Connect development and implementation, the Company has included $1.342 million in rate base for Customer Connect capital expenditures that have been closed to plant in service, net of accumulated depreciation and ADIT; $0.068 million in related depreciation expense; and $0.012 million in related ad valorem tax expense.[30]

Q. How does the Company's request in this proceeding compare to the DEI request in the pending proceeding before the Indiana Utility Regulatory Commission?

A. DEK seeks to include the development and implementation O&M expenses in

[27] Response to AG-DR-01-007. I have attached a copy of that response as my Exhibit___(LK-11).
[28] Direct Testimony of Retha Hunsicker at 2-7, 22 and Direct Testimony of Amy Spiller at 23.
[29] *Id.*
[30] Response to AG-DR-02-012. I have attached a copy of that response as my Exhibit___(LK-12).

operating income rather than defer the expenses as a regulatory asset and include the regulatory asset in rate base in this proceeding. In contrast to DEK in this proceeding, DEI seeks authorization to defer the Customer Connect development and implementation O&M expenses as a regulatory asset until the Customer Connect implementation date in Fall 2022.[31]

Q. Are the Customer Connect development and implementation expenses recurring?

A. No. These are one-time costs incurred to develop and implement the new platform. After the new platform is implemented, the Company will incur O&M expense for the new platform; however, the new expenses will be offset by savings in O&M expense that no longer will be incurred to operate and maintain the old CIS, which will be retired.

Q. Do the development and implementation O&M expenses have future value to customers?

A. Yes. In this respect, the O&M expenses are similar to the capital expenditures included in construction work in progress and plant in service. The fact that a portion of the development and implementation costs have and will continue to be expensed is due

[31] Direct Testimony (Revised) of Christa Graft at 27-28 in IURC Cause No. 45253. I have attached a copy of the relevant pages of Ms. Graft's testimony from that proceeding as my Exhibit___(LK-13).

solely to very specific accounting requirements for software development and implementation costs found in generally accepted accounting principles ("GAAP").

Q. What is your recommendation?

A. I recommend that the Commission remove the development and implementation O&M expenses from the revenue requirement and direct the Company to defer these expenses as a regulatory asset because they have future value and are nonrecurring. This recommendation is consistent with DEI's request to defer these expenses in its pending rate case before the IURC. I also recommend that the regulatory asset be included in rate base and amortized over the same service life used for the depreciation rate applied to the plant costs in the next base rate proceeding.

C. <u>Credit/Debit Card And Other Electronic Payment Convenience Fees Expense</u>

Q. Describe the Company's request to include credit/debit card and other electronic payment convenience fees in the base revenue requirement.

A. The Company proposes to discontinue the transaction (convenience) fees presently charged to residential customers when they elect to pay their bills via credit/debit card or electronic check, include all the transaction fees paid to the third-party vendor in the base revenue requirement, and then charge all customers for these fees as an operating expense.[32] The Company estimates that the convenience fees expense will be $0.493 million in the test year.[33] This expense reflects the Company's forecast growth in such forms of electronic payment and the fees expense as more customers elect to use these forms of payment.

Q. If more of the Company's customers pay their bills through such forms of electronic payments, will there be savings from reductions in other expenses that will offset in whole or part the increases in expense from increased customer participation?

A. Yes. There will or should be reductions in various other expenses that presently are incurred by the Company and recovered in the base revenue requirement. These other expenses include customer payment processing expense, call center expense, uncollectible accounts expense, and interest expense. The Company presently incurs customer payment processing expenses for payments made via check or money order, payments via cash or check at a pay station, or payments via bank draft or paperless billing.[34] The Company presently incurs expenses to respond to customers who call to pay by telephone or who are dissatisfied.[35] The Company presently incurs expenses for customers "who do not pay on time and enter the credit collections cycle."[36] The

[32] Direct Testimony of Lesley Quick at 8-10.
[33] Direct Testimony of Sarah Lawler at 12.
[34] Direct Testimony of Lesley Quick at 8.
[35] *Id.,* 12-13.
[36] *Id.,* 12.

Company presently incurs uncollectible accounts expense and interest expense in the form of a discount in accounts receivables proceeds when it sells its receivables to Cinergy Receivables.[37]

Q. Has the Company reflected the savings from the reductions in these expenses that will or should result from the growth in credit/debit card and other electronic transactions in the test year?

A. No. The Company made no adjustment to reflect the savings in uncollectible accounts expense, payment processing expense, or any other expenses, asserting that "the impact, if any, is not known at this time."[38]

Q. Is the Company's claim that the reductions in expense are "not known at this time" a valid reason to not reflect these savings if the Commission approves the Company's proposal to recover the credit/debit card and electronic transactions convenience fees in the base revenue requirement?

A. No. The actual transaction volume and related convenience fees the Company seeks to recover from all customers also are "not known at this time." The Company estimated the expense for the test year based on various assumptions.[39] The Company

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[37] Direct Testimony of Sarah Lawler at 12.
[38] Response to AG-DR-02-013. I have attached a copy of that response as my Exhibit___(LK-14).
[39] *Id.*

could have estimated the reductions in expense for the test year. The Company acknowledged that there would be savings. It simply made the decision not to estimate or include the reductions in expense.

Q. What is your recommendation?

A. I recommend that the Commission deny the Company's request to recover these fees as an expense in the revenue requirement instead of charging customers directly who elect to use this form of payment. The Company failed to reflect any offsetting reductions in expense. Nor should the Company be allowed to supplement its filing in Rebuttal Testimony to provide such quantifications in order to justify and salvage this proposed adjustment to increase expense. It had the opportunity to provide the savings in response to AG discovery, but chose not to do so. It would disadvantage the AG if the Company were allowed to provide such quantifications after the AG no longer has the ability to conduct discovery and after the AG has filed Direct Testimony in response to the Company's filed case.

Q. Do you oppose the Company's request to discontinue the transaction-specific fees charged to residential customers?

A. No, assuming that the Commission adopts my recommendation to deny the Company's request to recover these fees as an expense in the revenue requirement. Otherwise, I oppose the Company's request to charge all customers for the expense incurred to benefit a subset of customers that will be relieved from paying the transaction-specific fees.

D. <u>Payroll Tax Expense On Incentive Compensation Payroll Expense</u>

Q. Describe generally the Company's adjustments to remove incentive compensation payroll expense tied to the achievement of financial targets.

A. The Company removed incentive compensation payroll expense tied to the achievement of financial targets for the short-term incentive plan, long-term incentive plan, and the restricted stock units.

Q. Do the Company's proposed adjustments remove all incentive compensation expenses tied to the achievement of financial targets?

A. No. The Company failed to remove the payroll tax expense on the incentive compensation payroll expense. These payroll tax expenses would not have been incurred but for the payroll expense tied to the achievement of financial targets.

Q. What is the effect of removing these related payroll tax expenses?

A. The effect is a $0.065 million reduction in other taxes expense and a $0.066 million reduction in the revenue requirement.

E. <u>Supplemental Executive Retirement Plan Expense</u>

Q. Describe the Company's request to include Supplemental Executive Retirement Plan expense in the base revenue requirement.

A. The Company requests recovery of $0.122 million in Supplemental Executive Retirement Plan ("SERP") expense in the base revenue requirement, of which $0.008 million is for SERP expense incurred directly by DEK and $0.114 million for the SERP expense incurred by DEBS that is allocated to DEK.[40]

These expenses are incurred to provide certain highly compensated executives retirement benefits in addition to the benefits otherwise available through the Duke Energy pension and other postretirement benefit plans. These are considered to be non-qualified plans because the additional compensation exceeds deductible compensation limits set forth in the Internal Revenue Code.

Q. Has the Commission disallowed SERP expense in other proceedings when the issue has been raised?

A. Yes. The Commission stated in Case No. 94-355:

> The Attorney General's second adjustment would reduce expenses by $41,789 for SERP costs directly incurred by Cincinnati Bell because the Commission has previously removed from cost of service the cost of plans when benefits for highly compensated

[40] Response to AG-DR-01-044. I have attached a copy of that response as my Exhibit___(LK-15).

> employees exceed the pension plan for all employees." Not surprisingly, we find the adjustment should be accepted.[41]

The policy rationale for exclusion of SERP costs is the same as that cited by the Commission more recently to deny recovery of 401(k) plan matching contributions that a utility makes on behalf of employees who also participate in a defined benefit plan.[42] For example, in Case No. 2016-00169,[43] the Commission stated: "The Commission believes all employees should have a retirement benefit, but finds it excessive and not reasonable that Cumberland Valley continues to contribute to both a defined-benefit pension plan as well as a 401(k) plan for salaried employees."[44]

In this proceeding, the Company's desire to recover SERP expenses from customers, instead of shareholders, is an attempt to make an end-run around the Commission's prohibition against recovery of excessive expenses incurred pursuant to multiple retirement plans. The Commission's existing policy of excluding expenses for multiple supplemental retirement programs available to salaried employees is even more crucial in the context of SERP, which is available exclusively to highly-compensated executives.

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[41] *In Re Application of Cincinnati Bell Telephone Co*., Case No. 94-355, p. 16. *See also, In Re Application of Louisville Gas & Electric Co*., Case No. 90-158, Final Order dated Dec. 21, 1990, p. 27.

[42] *See, e.g., In Re Electronic Application of Louisville Gas & Elec. Co. for an Adjustment of Rates*, etc., Case No. 2016-00371, Final Order dated June 22, 2017, pp. 16-17.

[43] *In Re* Application of Cumberland Valley Electric, Inc. for a General Adjustment of Rates, Case No. 2016-00169, Final Order dated Feb. 6, 2017.

[44] *Id*. at 10.

Q. What is your recommendation?

A. I recommend that the Commission deny the Company's request to recover this expense, which DEK incurs primarily through DEBS affiliate charges. The SERP expense is discretionary. It is incurred to attract, retain, and reward highly compensated employees whose interests are more closely aligned with those of the Duke Energy shareholders than DEK's customers. It is not necessary to provide regulated utility service. It is not reasonable to charge utility customers for this expense.

F. <u>Amortization of Refunds Received Pursuant to FERC Opinion 494</u>

Q. Describe the refunds that DEK received as a result of FERC Opinion 494.

A. DEK recorded two refunds in 2018 summing to $8.0 million as credits to transmission O&M expense in account 561800 after the FERC issued Opinion 494 approving a settlement agreement entered into by most of the PJM transmission owners, including DEK, and the PJM state regulatory commissions. The refunds were due to overcharges to western PJM transmission owners, including DEK, for Regional Transmission Expansion Plan ("RTEP") projects built in the east.[45] The first refund, for $4.1 million, relates to overcharges in the years 2012-2015. The second refund, for

[45] DEK 2018 FERC Form 1 at 123.11. I have attached a copy of the applicable Form 1 page as my Exhibit___(LK-16).

$3.9 million, relates to overcharges in the years 2016-mid-2018.[46]

Q. Did DEK defer these refunds as regulatory liabilities to amortize to customers in a future rate proceeding?

A. No. DEK took the refunds to income in 2018 as credits to transmission O&M expense. DEK argues that "[t]he RTEP costs for the period 2012 through 2015 have not been recovered from customers; so, the refunds are for costs borne exclusively by the shareholders."[47] Similarly, DEK argues that the RTEP costs for the period 2016 through April 2018 "were borne exclusively by shareholders; consequently, customers are not entitled to refunds of costs that were not being recovered in rates."[48] However, DEK now agrees that the refunds for the period May 2018 through June 2018 should be deferred and amortized to customers in this rate proceeding because "customers were charged RTEP" for those months.[49]

Q. Provide a history of the transmission O&M expenses included in the base revenue requirement compared to the actual expenses incurred.

A. In Case No. 2006-00172, the Company's revenue requirement included $16.940 million in transmission O&M expense (accounts 560-574).[50] During that case, DEK

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[46] Response to AG-DR-02-032. I have attached a copy of that response as my Exhibit___(LK-17).
[47] *Id.*, at (a).
[48] *Id.*, at (e).
[49] *Id.*
[50] AG-DR-02-034. I have attached a copy of that response as my Exhibit___(LK-18).

was a member of MISO. The Company's revenue requirement included its forecast MISO charges. DEK exited MISO and joined PJM in 2012. In every year 2012 through 2015, DEK actually incurred transmission O&M expense, including the RTEP charges, which commenced in 2013, that were less than the $16.940 million included in the base revenue requirement. More specifically, DEK incurred $13.476 million in 2012, $10.230 million in 2013, $13.842 million in 2014, and $16.184 million in 2015. It then incurred $19.418 million in 2016, $17.246 million in 2017, and $20.674 million in 2018 (before recording the refund).[51]

Q. During the years 2012 through 2018, did the Company recover more in revenues than the transmission expense it actually incurred during those years?

A. Yes. It recovered substantially more without consideration of the refund. Over that seven-year period, DEK recovered at least $118.580 million in revenues for transmission expense, without consideration of the effects of sales growth on its base revenues, but actually incurred only $111.070 million in transmission O&M expense without consideration of the refund. It incurred only $103.070 million in transmission O&M expense after consideration of the refund.

Q. Is the Company's argument valid that it did not recover the RTEP costs from

[51] Copies of FERC Form 1 pages for each applicable year reflecting transmission expenses are attached as my Exhibit___(LK-19).

customers, so therefore it should not defer and amortize the refund to customers?

A. No. This argument is logically flawed. It was a member of MISO when base rates were set in Case No. 2006-00272. It exited MISO and became a member of PJM in 2012. It no longer incurred MISO expenses, but started to incur PJM expenses in lieu of the MISO expenses starting in 2012. Arguably, DEK's base rates did not include any PJM charges until base rates were reset in May 2018 as the result of Case No. 2017-00321. Yet, its base rates did include $16.940 million in annual transmission O&M expense, including MISO charges.

Since DEK's base rates were reset in Case No. 2006-00272, and after it joined PJM, its actual transmission O&M expense was less than the cumulative revenues for the recovery of transmission expense until its base rates were reset as the result of Case No. 2017-00321. Yet, DEK did not file a rate case to reflect its lower transmission expense after it joined PJM. Instead, DEK continued to recover the $16.940 million annually and retained the savings, and it did so without consideration of the origin of the expenses and irrespective of whether it was a member of MISO or PJM.

Q. Has the Commission previously addressed the amortization and return of RTEP refunds pursuant to FERC Opinion 494 for another utility?

A. Yes. In Case No. 2019-00349, the Commission directed Kentucky Power Company to amortize and return $5.2 million to its customers related to the RTEP refunds pursuant to FERC Opinion 494.

Q. What is your recommendation?

A. I recommend that the Commission direct the Company to defer, amortize, and return the entirety of the $8.0 million refund to its customers. The Company already has agreed to defer, amortize, and return $0.260 million to its customers. I recommend that the Commission direct the Company to amortize the entirety of the $8.0 million over the five years proposed by the Company for the $0.260 million.

Q. What is the effect of your recommendations?

A. The effect is a $1.600 million reduction in transmission expense and a $1.603 million reduction in the revenue requirement.

G. Duke Energy Business Services Cost Of Capital

Q. Describe the DEBS charges to the Company for a *return on* its so-called "rate base" costs.

A. The Company included $0.751 million in DEBS affiliate charges for a *return on* its so-called "rate base" costs in the revenue requirement.[52] DEBS is an affiliate service company that provides certain centralized and shared services to all Duke Energy

[52] Response to AG-DR-01-050, including Attachment.

utilities, including the Company.[53] In addition to other costs, DEBS charges the Company a *return on* its so-called "rate base" costs, including a gross-up for income taxes, ostensibly in accordance with the Service Company Utility Service Agreement between DEBS and DEK.[54,55] DEK witness Mr. Setser describes the costs charged by DEBS to DEK, including the "return" (cost of capital) and "taxes" as follows:

> "Cost", as used in the Service Company Utility Service Agreement and Non-Utility Service Agreement, means fully embedded cost, which is the sum of: (1) direct costs; (2) indirect costs; and (3) cost of capital . . . Indirect costs include, but are not limited to, overhead costs, administrative support costs, and taxes. Cost of capital represents financing costs, including, but not limited to, interest on debt and a fair return on equity to shareholders.[56]

However, the calculation of this *return on* so-called "rate base" costs is not defined in the Service Company Utility Service Agreement, the contract between DEBS and DEK for the provision of and payment for centralized and shared services. Nor is the return based on DEBS' actual cost of capital. Instead, DEBS calculates and charges DEK a so-called "proxy" return that uses DEK's current authorized rate of return grossed-up for income taxes.[57]

In its calculation of the charges to DEK, DEBS then applies this "proxy" return to a proxy "rate base," which it calculates as the sum of its net plant in service, prepaid

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[53] Direct Testimony of Amy Spiller at 6-7.
[54] Direct Testimony of Jeffrey Setser at 3-5 and Attachment JRS-1.
[55] Responses to AG-DR-01-050 and AG-DR-01-051. I have attached a copy of those responses as my Exhibit___(LK-20).
[56] Direct Testimony of Jeffrey Setser at 16.
[57] Response to AG-DR-02-045. I have attached a copy of that response as my Exhibit___(LK-21).

pension asset, and inventories, less the related net liability ADIT. The DEBS calculation of this proxy "rate base" is not consistent with the DEK calculation of rate base reflected in its filing in this case. For example, the DEBS calculation includes a prepaid pension asset, which DEK does not include in rate base, and it does not include other offsets that would further reduce rate base.

Q. How does the DEBS' proxy return compare to its actual cost of capital?

A. In contrast to this "proxy" return, the DEBS *actual* cost of financing is *significantly* less than the DEK cost of capital. The DEBS actual cost of capital is limited to interest on short term intercompany debt primarily incurred through the Duke Energy Money Pool, an intercompany financing arrangement that allows the Duke Energy utilities to borrow through the issuance of commercial paper and/or from each other. Pursuant to the terms of the Money Pool Agreement, DEBS is able to access funds based on low-cost commercial paper borrowings and excess funds from other affiliates.

Q. Does it make a difference if the assets and related costs are incurred and financed by DEBS or if they are incurred and financed by DEK?

A. Yes. It does matter which entity owns assets and incurs and finances the costs of those assets. The DEK cost of capital is significantly greater than the DEBS cost of capital. The DEK revenue requirement should not be increased based on charges for costs that

DEBS does not actually incur under the pretense that the DEBS and DEK costs of capital are equivalent; they clearly are not.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's request for recovery of DEBS charges for a "proxy" return on a proxy rate base. Instead, I recommend that the Commission allow recovery of an allocation of the DEBS annual short-term interest expense.

Q. What is the effect of your recommendation?

A. The effect is a $0.678 million reduction in DEBS charges for cost of capital, consisting of the elimination of $0.751 million in charges for the "proxy" return on a proxy rate base, and a $0.073 million increase in charges for an allocation of DEBS annual short-term interest expense.

H. <u>Amortization Of Duke Energy Business Services EDIT As A One-Time Refund Or Credit</u>

Q. Describe the Duke Energy Business Services charges to the Company for income tax expense.

A. DEBS charges DEK income tax expense based on a gross-up of the equity component of the "proxy" *return on* that I described in the prior section of my testimony. DEBS incurs and records both current income tax expense on its taxable income and deferred income tax expense on temporary differences used to calculate its current income tax expense. It then accumulates the deferred income tax expense as ADIT.[58]

Q. How did the Tax Cuts and Jobs Act affect the ADIT recorded on DEBS accounting books?

A. Before the TCJA was enacted, DEBS recorded the federal ADIT on its accounting books at the federal income tax rate of 35%. When the TCJA was enacted in late 2017, DEBS remeasured the ADIT at the new federal income tax rate of 21%, and recorded the reduction as EDIT. Unlike DEK, DEBS did not retain the EDIT on its accounting books for future refund to DEK and other affiliates. Instead, DEBS recorded the EDIT as a reduction to deferred income tax expense, without an offsetting deferral to a liability, and, in that manner, took the EDIT to income in 2017.[59]

Q. Did DEBS refund the EDIT to the Company and its other affiliate companies?

A. No. DEBS unilaterally recorded the EDIT as an increase to income in 2017.

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[58] Response to AG-DR-01-002, which provides the DEBS trial balance for 2016, 2017 and 2018. I have attached a copy of the applicable DEBS trial balance pages from that response as my Exhibit___(LK-22).

[59] Response to AG-DR-01-019. I have attached a copy of that response as my Exhibit___(LK-23). The Company states that "DEBS remeasured its ADIT based on the new federal corporate income tax rate of 21% and removed the excess ADIT through the income statement."

Q. Was it just and reasonable for DEBS to take the EDIT to income in 2017 instead of establishing a liability and/or refunding the EDIT to the Company and other affiliate companies?

A. No. This unilateral action was particularly egregious given that DEBS collected the ADIT at the federal income tax rate of 35% from the Company in prior years through the "proxy" *return on* the "proxy" rate base that I previously described. As a service company, DEBS should have refunded the EDIT to the Company and other regulated utility affiliate companies so that they could refund these amounts to their customers.

DEBS should have refunded the EDIT to the Company and other regulated utility affiliate companies even if it had not charged them for income tax expense at the federal income tax rate of 35%. The Company recovers charges from DEBS in the same manner as if it had incurred the costs on its own behalf. DEBS acquired assets and depreciated those assets for book and income tax purposes. DEBS used bonus depreciation and Modified Accelerated Cost Recovery System ("MACRS") accelerated depreciation for income tax purposes, which created temporary differences and the resulting ADIT for the bonus and accelerated tax depreciation in excess of straight-line depreciation. DEBS charged the Company and other affiliate companies for the depreciation expense on these assets. Thus, DEK is entitled to any tax benefits, including the EDIT due to the remeasurement of the ADIT.

Q. What is your recommendation?

A. I recommend that the Commission allocate the DEBS EDIT to the Company in the same manner that the DEBS depreciation expense is allocated to the Company and then refund the EDIT to the Company's customers as a one-time refund or credit.

Q. What is the effect of your recommendation?

A. The effect is a $0.214 million one-time refund or credit. The effect on the revenue requirement is the retail jurisdictional effect of the EDIT grossed-up for income taxes. The total DEBS EDIT at December 31, 2017 was $21.725 million.[60] DEK would have been allocated $0.161 million of this amount if DEBS had not retained the EDIT and recorded it to income in 2017.[61] It is then necessary to gross-up the DEBS EDIT to a revenue equivalent in the same manner that the Company's EDIT was grossed-up to a revenue requirement equivalent for refund purposes.

I. Increases To Depreciation Rates Only Two Years After The Commission Adopted Present Depreciation Rates Are Unnecessary And Unduly Aggressive

Q. Describe the Company's request to change depreciation rates in this proceeding.

A. The Company requests changes in its depreciation rates in this proceeding less than two years after the Commission adopted its proposed depreciation rates in Case No.

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[60] Response to AG-DR-01-019; sum of DEBS entries to accounts 190, 282, and 283. I have attached a copy of that response as my Exhibit___(LK-23).

[61] Response to AG-DR-01-018. The DEBS allocation factor used to allocate/charge depreciation expense for DEBS' assets to DEK Electric is 0.74%. I have attached a copy of that response as my Exhibit___(LK-24).

2017-00321, albeit using the average life group ("ALG") procedure in lieu of the Company's proposed equal life group ("ELG") procedure in that prior proceeding. The Company does not seek to change from ALG to ELG in this proceeding, meaning that its proposed changes in its depreciation rates all relate to the depreciation parameters adopted less than two years ago, not to the use of the ALG procedure.

Q. What are the effects of the Company's requested depreciation rates on depreciation expense and the requested rate increase in this proceeding, as compared to the present depreciation rates and depreciation expense?

A. The requested changes in depreciation rates in this proceeding increase depreciation expense and the requested rate increase by $7.431 million annually, all else equal.[62] In the context of the request to increase base rates in this proceeding, the requested changes in depreciation rates represent 16.3% of the Company's proposed rate increase of $45.634 million. If the Company's requested increases are approved in this proceeding, there will be additional increases in the depreciation expense included in the ESM Rider and the related ESM revenue requirement, although these increases are not specifically addressed in the Company's Application in this proceeding.

If adopted, the requested changes in depreciation rates will increase the depreciation expense for the East Bend (steam production) plant accounts by $4.694

[62] Response to AG-DR-01-033. I have attached a copy of that response as my Exhibit___(LK-25).

million (24.0%), for the Woodsdale CTs and solar (other production) by $1.671 million (14.4%), for the distribution plant accounts (primarily station equipment, overhead conductors and devices, and underground conductors and devices) by $1.245 million (9.9%), and for common plant allocated to electric by $0.054 million. If adopted, the requested changes in depreciation rates will nominally reduce depreciation expense by $0.125 million for transmission plant accounts and for general plant accounts by $0.108 million.

Q. In your experience, is it unusual for a utility to seek changes in depreciation rates and significant increases in depreciation expense a mere two years after a Commission adopts new depreciation rates?

A. Yes. This is very unusual, unless there are significant known changes in facts and circumstances for certain assets, such as accelerated retirement dates for production plant assets. In my experience, the industry norm for review and reconsideration of depreciation rates is considered to be no more frequently than three to five years. In practice, some utilities do not seek to change rates for ten or more years. With respect to the depreciation study two years ago and the one in this proceeding, Mr. Spanos states in both studies that "For most plant accounts, the application of such rates . . . is reasonable for a period of three to five years."[63]

[63] Attachment JJS-1 to Direct Testimony of John Spanos at 50 of 364.

Q. Are there any significant known changes in the depreciation parameters (assumptions) for plant at December 31, 2018, the depreciation study date in this proceeding, compared to the depreciation parameters for plant at December 31, 2016, the depreciation study date in Case No. 2017-00321?

A. No. The proposed changes in certain parameters are changes in assumptions or estimates, including estimates of future costs that have not yet been incurred, e.g., increases in net negative interim and terminal salvage that are recovered pre-emptively.

Q. Is there any urgency to revise depreciation rates in order to reflect changes in the depreciation parameters (assumptions and estimates) in this proceeding compared to the prior proceeding, as advocated by Mr. Spanos?

A. No. The recovery of actual plant costs and estimated terminal and interim net salvage costs through depreciation expense is a matter of timing. The Commission must determine reasonable recovery of these actual and estimated costs, which necessarily includes a review and assessment of all parameters included in a depreciation study, such as service lives, interim retirement patterns (survivor curves), and interim and terminal net salvage. The actual depreciation expense is accumulated in the accumulated depreciation accounts and can be compared at any time to the actual plant costs. The remaining net book value (plant costs less accumulated depreciation) is included in rate base and earns a rate of return until it is recovered through depreciation expense.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed changes to depreciation rates and the resulting increases in depreciation expense in this proceeding. The Company's request to increase depreciation rates only two years after the Commission approved the present depreciation rates is unduly aggressive and unnecessary. In particular, there is no urgency or need to revise assumptions and estimates of unknown future costs for net negative salvage compared to the Company's own estimates of these costs a mere two years ago in the prior proceeding. The Commission will have the opportunity to review the depreciation rates, including any changes in these assumptions and estimates, in subsequent proceedings.

J. Terminal Net Salvage For Steam Production And Other Production Plant Accounts

Q. Describe the terminal net salvage included in the net salvage for steam and other production plant accounts in the proposed depreciation rates.

A. Mr. Spanos added terminal net salvage (decommissioning) to the remaining net book value of the East Bend (steam production) and Woodsdale CTs (other production) to calculate the depreciation expense and net negative salvage included in the proposed depreciation rates for these plant accounts.

Mr. Spanos relied on estimates of terminal net salvage based on a decommissioning study performed in 2017 by Burns & McDonnell ("BMD"). The BMD decommissioning estimate for the East Bend plant (steam production) plant is $34.334 million in 2016 dollars.[64] This estimate includes an additional 5%, or $1.693 million, for "indirect costs" (overhead costs) that BMD estimates the Company will incur and another $6.771 million in "contingency costs" that BMD estimates the Company could incur in the event the BMD cost estimate is otherwise insufficient.[65]

The BMD decommissioning estimate for the Woodsdale CTs (other production) plant is $6.267 million in 2016 dollars.[66] This estimate includes an additional 5%, or $0.403 million, for "indirect costs" (overhead costs) that BMD estimates the Company will incur and another 20%, or $1.611 million, for "contingency costs" that BMD estimates the Company could incur in the event that the BMD cost estimate is otherwise insufficient.[67]

For purposes of his depreciation study in this proceeding, Mr. Spanos restated and increased the BMD estimate for the East Bend plant to $60.586 million in 2041 dollars and the BMD estimate for the Woodsdale CTs to $8.555 million in 2032

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[64] Response to AG-DR-01-023 Attachment 6 – Terminal Net Salvage. I have attached a copy of that response as my Exhibit___(LK-26).

[65] Response to STAFF-DR-02-146. I have attached a copy of that response as my Exhibit___(LK-27).

[66] Response to AG-DR-01-023 Attachment 6 – Terminal Net Salvage. I have attached a copy of that response as my Exhibit___(LK-26).

[67] Response to STAFF-DR-02-146. I have attached a copy of that response as my Exhibit___(LK-27).

dollars. Mr. Spanos used a 2.5% annual escalation factor for this purpose.[68]

Q. Is it appropriate to include contingency costs in the estimates developed for ratemaking purposes?

A. No. This simply increases the estimated decommissioning cost above the best estimate developed by BMD, the engineering contractor retained to develop such an estimate to support the Company's ratemaking request decades before the planned retirements of the generating units. It should be noted that BMD actually performs decommissioning work for utilities and has a direct interest in establishing a high baseline for any future bid that it may make to decommission the East Bend and Woodsdale CTs production facilities. In fact, some may consider BMD's development and support of a decommissioning cost estimate in rate case proceedings a conflict of interest, at least from the perspective of DEK's customers, if BMD plans to and will be allowed to bid on the actual decommissioning projects at some future dates. In any event, the proposal to include a contingency in addition to its best estimate, tends to strengthen such a conclusion.

While it may be appropriate for future demolition contractors to include contingency costs when they actually develop their competitive bids 22 years from now if and when the East Bend plant is retired in 2041 and 13 years from now if and

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[68] Response to AG-DR-01-031. I have attached a copy of that response as my Exhibit___(LK-28).

when the Woodsdale CTs are retired in 2032, it is not appropriate to do so now in estimates developed solely for ratemaking purposes. The estimate reflected for ratemaking purposes will tend to become the "bogey" for future demolition contractors, including, potentially, BMD, when it actually bids on the project.

The BMD estimate without contingency costs is likely the least biased and is the best estimate to use for ratemaking purposes. The BMD estimate without contingency costs is based on its so-called "bottoms-up" approach to developing the estimates. The Commission should not simply assume that the cost will be 20% more than this estimate any more than it should assume that the cost will be 20% less than this estimate.

The decommissioning cost estimate is inherently incapable of actual measurement at this time because the costs have not yet been incurred and the actual cost is uncertain and unknown. The Company may retire the East Bend plant and/or the Woodsdale CTs at later dates than the probable retirement dates reflected in the depreciation study. The competitive bids when the plants actually are retired may be less than the BMD estimates developed decades before the demolition work is performed. In 13 or more years, there may be improvements in technology, increases in productivity, and/or increases in net salvage income that will reduce the actual cost compared to the BMD estimates.

Q. Is it appropriate to escalate the terminal net salvage costs in the estimates used

for ratemaking purposes?

A. No. An escalation methodology improperly "frontloads" the present ratemaking recovery of an estimate of future costs in future dollars, all of which are uncertain. The Company's proposed escalation simply assumes that costs will escalate and that there will be no reductions in costs over the next 13 to 22 or more years until the demolition work actually is performed. It assumes that there will be no changes in the physical dismantling and site restoration processes assumed by BMD. It assumes that there will be no efficiencies from advances in technology, equipment and/or disposal, and assumes that there will be no improvements in productivity, any of which will offset potential future inflation in costs.

In addition, the use for 2019 ratemaking purposes of estimated 2041 future dollars for East Bend and 2032 future dollars for the Woodsdale CTs is an inherent mismatch and forces today's customers to subsidize future customers. If the cost estimate or the actual cost escalates in future years, then the increases, to the extent they are reasonable and prudent, can be reflected in periodic revisions and updates in the deprecation studies used to develop depreciation rates and the resulting depreciation expense.

Q. What are your recommendations?

A. I recommend that the Commission reject the Company's proposed changes in depreciation rates and the resulting increases in depreciation expense and the revenue requirement in this proceeding. As an alternative, if the Commission decides to revisit depreciation rates in this proceeding, then I recommend that the Commission simply use the BMD decommissioning estimates without contingency and without escalation for the terminal net salvage component of the proposed depreciation rates for the East Bend and Woodsdale CTs plant accounts.

Q. What is the effect of your alternative recommendation regarding the terminal net salvage for East Bend and the Woodsdale CTs?

A. The effect is a $2.111 million reduction in the revenue requirement. The reduction consists of a reduction of $2.151 in depreciation expense, the gross up related to the PSC maintenance fees, and the return on rate base effects due to changes in accumulated depreciation and ADIT.

K. <u>Life Span For Woodsdale CTs</u>

Q. Describe the life span parameter for the Woodsdale CTs reflected in the requested depreciation rates for the other production plant accounts.

A. The depreciation study assumes a life span of 40 years and that the probable retirement dates will be in 2032 for the Woodsdale CTs, only 13 years from now, and only slightly more than 12 years after the end of the test year.

Q. Is there any evidence that the Company plans to retire the Woodsdale CTs in 2032?

A. No. The evidence is to the contrary. In the Company's most recent integrated resource plan ("IRP") filing, the Company did not reflect the retirement of the Woodsdale CTs capacity in 2032 and did not address replacement of the capacity, which would be necessary if, in fact, the Company planned to retire those units in 2032.[69] In that proceeding, the AG asked the Company to "[p]rovide the remaining lifespan of the Woodsdale CT units by unit."[70] The Company responded that "[a] lifespan of 40 years was assigned to the CT units at Woodsdale implying an end of life date of 2032 for each of the Woodsdale units based on the in-service date of 1992. The remaining lifespan of any of these units can be extended through additional capital expenditure if deemed economically prudent at the time the additional investment is required by the physical condition of the unit."[71]

In addition, the Company recently incurred approximately $55 million to add a diesel fuel capability to the Woodsdale facility. This was necessary to ensure that the units remain available in the event of a natural gas curtailment and to avoid PJM performance penalties.[72] This significant and recent investment in the facility is further evidence that the units are not likely to be retired in 2032.

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[69] Case No. 2018-00195.
[70] Response to AG-DR-02-001 in Case No. 2018-00195. I have attached a copy of that response as my Exhibit___(LK-29).
[71] *Id.*
[72] Case No. 2018-0195, Application.

Q. What are the actual life spans of CT units?

A. The actual life spans of CT units that remain economic typically extend to 50 or more years. This is consistent with information for CT units publicly available from the Energy Information Administration ("EIA") through 2018 and published by the EIA in early 2019.[73] For example, the Duke Energy Florida, LLC Avon Park CT and Higgins 1-4 CTs are projected to be retired this year and in 2020 after 48-51 years of service, according to the EIA data. The Duke Energy Florida, LLC P L Bartow 1-2 CTs have been in service for 47 years through the end of 2018 and have no planned retirement date, according to the EIA data.

The Kentucky Utilities Company Haefling 1 and 2 CTs have been in service for 49 years through the end of 2018 and have no planned retirement dates, according to the EIA data. The Louisville Gas & Electric Company ("LG&E") Cane Run 11 CT and Paddy's Run 11 and 12 CTs have been in service for 51 years through the end of 2018 and have no planned retirement dates, according to the EIA data. The LG&E Zorn 1 CT has been in service for 50 years through the end of 2018 and has no planned retirement date, according to the EIA data.

The Southern Indiana Gas & Electric Company Northeast 1 and 2 CTs have been in service for 56 and 55 years, respectively, through the end of 2018 and will be

[73] EIA Form 860 survey data regarding existing and planned generators and associated environmental equipment at electric power plants. https://www.eia.gov/electricity/data/eia860/

retired in 2019, which will result in actual service lives of 57 and 56 years, respectively, according to the EIA data.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed changes in depreciation rates and the resulting increases in depreciation expense and the revenue requirement in this proceeding. As an alternative, if the Commission decides to revisit depreciation rates in this proceeding, then I recommend that the Commission extend the Woodsdale CTs probable retirement date to 2042 and increase the life span by 10 years to 50 years. There is no evidence that the Woodsdale CTs suddenly will become uneconomic in 2032 and the Company has no present plans to retire those units in 2032.

Q. What is the effect of your alternative recommendation to extend the life span for the Woodsdale CTs to 50 years?

A. The effect is a $5.305 million reduction in the revenue requirement. The reduction consists of a reduction of $5.407 in depreciation expense, the gross up related to the PSC maintenance fees, and the return on rate base effects due to changes in accumulated depreciation and ADIT.

IV. COST OF CAPITAL ISSUES

A. Cost of New Long-Term Debt Issuance

Q. Describe the Company forecast cost of a new long-term debt issuance in the test year.

A. The Company forecasts that it will issue $50.000 million in intermediate/long-term debt at 4.0% on September 15, 2020.[74] It weighted the cost of this issuance for the portion of the test year that it will be outstanding.

The Company does not know whether it will issue five-year, ten-year, or thirty-year debt or some combination of those tenors. Consequently, it used the forward yield curves as of June 30, 2019 to forecast the cost of debt for each of those tenors and then weighted the five-year tenor at 10%, ten-year tenor at 35%, and thirty-year tenor at 55%. It forecast the cost of each tenor as the sum of the Treasury yield for the tenor plus a credit spread. Specifically, it forecast the Treasury yields for the five-year tenor at 1.85%, ten-year tenor at 2.16%, and thirty-year tenor at 2.62%. It added a credit spread to the five-year tenor of 1.30%, ten-year tenor of 1.50%, and thirty-year tenor of 1.75%.[75]

Q. Is the cost of this new long-term debt issuance reasonable given current interest

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[74] Schedule J-3 page 2 of 2.
[75] Response to STAFF-DR-02-054. I have attached a copy of that response as my Exhibit___(LK-30).

rates?

A. No. It is excessive based on current interest rates. The current five-year Treasury yield is 1.666%, ten-year Treasury yields are 1.842%, and thirty-year Treasury yields are 2.282%.[76] If the current Treasury yields are substituted for the Company's Treasury yields for each tenor, the credit spreads added, and the tenors weighted, then the cost of the debt issuance is 3.68%, not the 4.0% reflected by the Company in its filing.

Q. Should the Commission update the Treasury yields in the calculation of the interest rates for each tenor to reflect current yields?

A. Yes. I recommend that the Commission update the Treasury yields to reflect the most recent yields in the calculation of the current interest rates for each tenor.

Q. Have you quantified the effect on the Company's revenue requirement of the cost of a new intermediate/long-term debt issue using current interest rates?

A. Yes. The effect is a reduction of $0.056 million in the base revenue requirement. There will be an additional effect on the ESM revenue requirement, although I have not quantified this effect.

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[76] www.WSJ.com (December 6, 2019). I have attached a copy of the relevant source information as my Exhibit___(LK-31).

B. <u>Effect of Lower Return on Common Equity</u>

Q. Have you quantified the effect on the Company's revenue requirement of the return on equity recommendation sponsored by AG witness Mr. Richard Baudino?

A. Yes. The effect is a reduction of $4.761 million in the base revenue requirement. There will be an additional effect on the ESM revenue requirement, although I have not quantified this effect.

Q. Have you quantified the effect of each 0.10% return on common equity?

A. Yes. The effect of each 0.10% return on common equity is $0.595 million on the base revenue requirement. As I noted previously, there also is an effect on the ESM revenue requirement, although I have not quantified this effect.

Q. Describe the effect on the ESM revenue requirement in addition to the effect on the base revenue requirement.

A. The Commission historically has used the return on common equity set in the utility's most recent base rate proceeding in the return applied in other riders, such as the Company's ESM. Unlike the base revenue requirement, which in this proceeding will be based on a forecast test year, the ESM revenue requirement is based on rate base costs that actually have been incurred and the actual cost of long-term debt. Thus, a change in the return on equity in this proceeding will have an immediate effect (on a two-month lag basis) on the return on the total ESM rate base included in the ESM revenue requirement. This effect will continue until the Commission resets the return on equity in a future base or ESM proceeding.

Q. How does the pretax return on common equity requested by the Company compare to the AG recommendation?

A. The pretax return on common equity requested by the Company is 13.1%. The pretax return recommended by the AG is 12.0%. The pretax return is the return on common equity that must be recovered from ratepayers in the revenue requirement. It includes federal and state income taxes that must be recovered in the revenue requirement, but that are subtracted as expenses by the Company in computing its after tax return on equity. For this purpose, I also included the Company's proposed gross-up for the Commission maintenance fee.

V. PROPOSED NEW PROJECTS AND PROGRAMS

A. <u>New Battery Storage Project</u>

Q. Describe the Company's request to include the cost of a new battery storage project in rate base and the revenue requirement in this proceeding.

A. The Company proposes a new battery storage project as a pilot program with total estimated capital costs of $8.2 million and ongoing O&M expenses of $0.163 million annually after the project is in-service.[77] DEK witness Mr. Zachary Kuznar provides a more detailed description of this project.[78] The project "will give Duke Energy Kentucky valuable insight on how to incorporate energy storage into its existing operation to provide these bulk system benefits to its customers," according to Mr. Kuznar.[79] "Now is the time to gain the operational knowledge necessary to own and operate energy storage assets. The lessons learned from this project will enable the successful implementation of future projects," also according to Mr. Kuznar.[80] The project will only be implemented if it is approved by the Commission and the costs included in the revenue requirement.[81]

The Company has included $0.346 million in the revenue requirement for this project, including the grossed-up return on rate base and the related depreciation expense and ad valorem tax expense.[82] The return on rate base assumes an in-service date of December 31, 2020. The 13-month average amount included in the rate base is $2.4 million.[83] The annual revenue requirement in a future proceeding will be

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[77] Direct Testimony of Sarah Lawler at 15. See response to STAFF-DR-02-086 Attachment for the individual components included in the revenue requirement. Page 2 of the STAFF-DR-02-086 Attachment shows the plant addition in December 2020 included in the "Distribution Improvements" project class. I have attached a copy of that response as my Exhibit___(LK-32).

[78] Direct Testimony of Zachary Kuznar at 2-12.

[79] *Id.*4-5.

[80] *Id, 5.*

[81] *Id.*

[82] Direct Testimony of Sarah Lawler at 16 and the response to STAFF-DR-02-086 Attachment. I have attached a copy of that response as my Exhibit___(LK-32).

[83] *Id.*

approximately $1.384 million. The Company estimates that the project will generate $0.800 million in annual PJM ancillary services revenues, which it proposes to credit to customers through the Rider PSM, net of the operating expenses. In other words, the project is a net economic loser on an annual basis of approximately $0.747 million between future base rates and the Rider PSM ($1.384 million annual revenue requirement in base rates less $0.637 million annual credit in Rider PSM).

Q. Does it make sense for DEK to implement a pilot program at this time?

A. No. First, the project is not necessary for reliability. Second, the project is not economic. Third, the pilot program will be managed by another Duke Energy affiliate and/or DEBS, not DEK, and should be pursued by and allocated to the larger Duke Energy utilities, such as DEK's parent company, Duke Energy Ohio, not DEK, the smallest Duke Energy utility. Other Duke Energy utilities and other unrelated utilities can implement pilot programs and provide lessons learned to DEK for possible future deployment of this technology.

Q. What is your recommendation?

A. I recommend that the Commission reject this project and the related cost recovery. The battery storage project pilot program is discretionary and is an unnecessary cost.

B. <u>Electric Vehicle Charging Pilot Programs</u>

Q. Describe the Company's request that the Commission approve Electric Vehicle Charging ("EVC") pilot programs.

A. The Company seeks approval to implement EVC pilot programs consisting of an EV Fast Charge Program, Electric Transit Bus Charging Program and three Incentive Programs "to facilitate early utility system planning and to assist Duke Energy's customers and the broader public in the transition to an electric transportation infrastructure."[84] The Company assumes that the five EV Fast Charging station and the five Electric Bus Charging stations will be placed in service over five months starting in June 2020.[85]

The Company included $0.145 million in the revenue requirement for the return on the 13-month average amounts included in rate base, depreciation expense, and ad valorem tax expense.[86] In addition to the costs included in the revenue requirement in this proceeding, the Company seeks approval to defer incremental O&M expenses for the Electric Transit Bus Charging Program, incentive programs, and education and outreach.[87] It plans to seek recovery of this regulatory asset in a future rate case.[88]

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[84] Direct Testimony of Lang Reynolds at 2.
[85] Direct Testimony of Sarah Lawler at 16-17.
[86] Response to STAFF-DR-02-088 Attachment. I have attached a copy of that response as my Exhibit___(LK-33).
[87] Direct Testimony of Sarah Lawler at 17.
[88] Direct Testimony of Don Wathen at 23-24.

Further, the Company seeks to modify the Profit Sharing Mechanism ("Rider PSM") "to flow through to customers the "benefits" from its deployment of EVC stations."[89] More specifically, the Company proposes to credit the revenues less the O&M expenses incurred for the EV Fast Charging stations through the Rider PSM.[90]

Q. Does it make sense for DEK to implement these EVC pilot programs at this time?

A. No. First, these programs are not necessary for the provision of electric service. The programs are designed to develop EVC infrastructure, promote growth in electric transportation, and grow customer load, not to meet existing DEK customer requirements.

Second, the programs will not benefit all customers. In fact, they are carefully targeted subsidies to a very limited number of customers. There are presently only 320 electric vehicles registered in DEK's service territory.[91] The residential EV charging incentive will subsidize residential customers who buy specific fast charge equipment. The non-road electrification incentive program will subsidize commercial customers that buy electric forklifts and other electric equipment, including airport service equipment.

Third, the project is not economic. The Company offered no evidence to

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[89] *Id.*, at 19.
[90] Direct Testimony of Sarah Lawler at 17-18.
[91] Direct Testimony of Lang Reynolds at 5.

support its claim that the additional load will benefit DEK's customers through a broader base over which to allocate DEK's costs.[92]

Fourth, these are pilot programs and are only a down payment on additional investments and other costs that undoubtedly then will be premised on the "success" of the pilot programs, however that may be measured.

Fifth, the pilot programs will be managed by another Duke Energy affiliate, such as Duke Energy Carolinas, LLC, Mr. Reynolds' employer, and/or DEBS, not DEK. These pilot programs should be pursued by and allocated to the larger Duke Energy utilities, such as DEK's parent company, Duke Energy Ohio, not DEK, the smallest of the Duke Energy utilities. Other Duke Energy utilities and other unrelated utilities can implement pilot programs and provide lessons learned to DEK for possible future deployment of this technology.

Sixth, if the programs are beneficial to the DEK customers in the sense that incremental revenues will exceed incremental costs at some future date, then the Commission should look to private industry to develop this infrastructure to assume the risks and incur the costs.

Finally, DEK previously advised the Commission, in Case No. 2017-00427, that "even with demand response programs, the Company's actual operating capacity position in PJM is razor thin at best. Absent demand response, the Company's FRR

[92] *Id.*, at 3.

Plan would be deficient in the current delivery year and potentially for future years."[93] In that same case, the Commission noted that without DEK's DSM programs "additional capacity purchases would be required to ensure that its FRR plan is not deemed deficient", which would result in significant financial penalties, additional reserve margin penalties on its load forecast, and possibly a forced exit from the FRR construct.[94] Further, if short on capacity DEK would be limited to the bilateral capacity market as an FRR entity.[95] The potential for customers to have to pay for both the EVC pilot program costs up front, and for capacity on the back end if more is needed, with little or no substantial benefit, is reason enough to deny this proposal, especially given the potential of electric vehicle charging to have a significant impact on system capacity.[96]

Q. Does this complete your testimony?

A. Yes.

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[93] Direct Testimony of John A. Verderame, Case No. 2017-00427, *Electronic Annual Cost Recovery Filing for Demand Side Management by Duke Energy Kentucky, Inc.*, at 25 (Ky. Commission April 12, 2018); *See also* Petition for Rehearing, Case No. 2017-00427, at 7–16 (March 2, 2018).

[94] Order, Case No. 2017-00427, at 9–10 (Ky. Commission September 13, 2018).

[95] *Id*.

[96] *See* Case No. 2018-00348, *Electronic 2018 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities* Company, LG&E-KU 2018 IRP Volume I, at 5-30–32 (Ky. Commission October 19, 2018).

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

LANE KOLLEN, being duly sworn, deposes and states: that the attached is his sworn testimony and that the statements contained are true and correct to the best of his knowledge, information and belief.

Lane Kollen

Sworn to and subscribed before me on this
13th day of December 2019.

Notary Public

RANDY A. FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 25, 2020
COBB COUNTY, GEORGIA

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

ELECTRONIC APPLICATION OF DUKE	**)**	
ENERGY KENTUCKY, INC. FOR: 1) AN	**)**	
ADJUSTMENT OF THE ELECTRIC RATES;	**)**	
2) APPROVAL OF NEW TARIFFS;	**)**	**CASE NO. 2019-00271**
3) APPROVAL OF ACCOUNTING PRACTICES	**)**	
TO ESTABLISH REGULATORY ASSETS AND	**)**	
LIABILITIES; AND 4) ALL OTHER	**)**	
REQUIRED APPROVALS AND RELIEF	**)**	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

KENTUCKY OFFICE OF THE ATTORNEY GENERAL

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

DECEMBER 2019

EXHIBIT _____ (LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Mr. Kollen has more than thirty years of utility industry experience in the financial, rate, tax, and planning areas. He specializes in revenue requirements analyses, taxes, evaluation of rate and financial impacts of traditional and nontraditional ratemaking, utility mergers/acquisition and diversification. Mr. Kollen has expertise in proprietary and nonproprietary software systems used by utilities for budgeting, rate case support and strategic and financial planning.

EXPERIENCE

1986 to Present: **J. Kennedy and Associates, Inc.:** Vice President and Principal. Responsible for utility stranded cost analysis, revenue requirements analysis, cash flow projections and solvency, financial and cash effects of traditional and nontraditional ratemaking, and research, speaking and writing on the effects of tax law changes. Testimony before Connecticut, Florida, Georgia, Indiana, Louisiana, Kentucky, Maine, Maryland, Minnesota, New York, North Carolina, Ohio, Pennsylvania, Tennessee, Texas, West Virginia and Wisconsin state regulatory commissions and the Federal Energy Regulatory Commission.

1983 to 1986: **Energy Management Associates:** Lead Consultant.
Consulting in the areas of strategic and financial planning, traditional and nontraditional ratemaking, rate case support and testimony, diversification and generation expansion planning. Directed consulting and software development projects utilizing PROSCREEN II and ACUMEN proprietary software products. Utilized ACUMEN detailed corporate simulation system, PROSCREEN II strategic planning system and other custom developed software to support utility rate case filings including test year revenue requirements, rate base, operating income and pro-forma adjustments. Also utilized these software products for revenue simulation, budget preparation and cost-of-service analyses.

1976 to 1983: **The Toledo Edison Company:** Planning Supervisor.
Responsible for financial planning activities including generation expansion planning, capital and expense budgeting, evaluation of tax law changes, rate case strategy and support and computerized financial modeling using proprietary and nonproprietary software products. Directed the modeling and evaluation of planning alternatives including:

Rate phase-ins.
Construction project cancellations and write-offs.
Construction project delays.
Capacity swaps.
Financing alternatives.
Competitive pricing for off-system sales.
Sale/leasebacks.

CLIENTS SERVED

Industrial Companies and Groups

Air Products and Chemicals, Inc.
Airco Industrial Gases
Alcan Aluminum
Armco Advanced Materials Co.
Armco Steel
Bethlehem Steel
CF&I Steel, L.P.
Climax Molybdenum Company
Connecticut Industrial Energy Consumers
ELCON
Enron Gas Pipeline Company
Florida Industrial Power Users Group
Gallatin Steel
General Electric Company
GPU Industrial Intervenors
Indiana Industrial Group
Industrial Consumers for Fair Utility Rates - Indiana
Industrial Energy Consumers - Ohio
Kentucky Industrial Utility Customers, Inc.
Kimberly-Clark Company
Lehigh Valley Power Committee
Maryland Industrial Group
Multiple Intervenors (New York)
National Southwire
North Carolina Industrial Energy Consumers
Occidental Chemical Corporation
Ohio Energy Group
Ohio Industrial Energy Consumers
Ohio Manufacturers Association
Philadelphia Area Industrial Energy Users Group
PSI Industrial Group
Smith Cogeneration
Taconite Intervenors (Minnesota)
West Penn Power Industrial Intervenors
West Virginia Energy Users Group
Westvaco Corporation

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
Georgia Public Service Commission Staff
Kentucky Attorney General's Office, Division of Consumer Protection
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York State Energy Office
Office of Public Utility Counsel (Texas)

Utilities

Allegheny Power System
Atlantic City Electric Company
Carolina Power & Light Company
Cleveland Electric Illuminating Company
Delmarva Power & Light Company
Duquesne Light Company
General Public Utilities
Georgia Power Company
Middle South Services
Nevada Power Company
Niagara Mohawk Power Corporation
Otter Tail Power Company
Pacific Gas & Electric Company
Public Service Electric & Gas
Public Service of Oklahoma
Rochester Gas and Electric
Savannah Electric & Power Company
Seminole Electric Cooperative
Southern California Edison
Talquin Electric Cooperative
Tampa Electric
Texas Utilities
Toledo Edison Company

Expert Testimony Appearances
of
Lane Kollen
As of December 2019

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.

Expert Testimony Appearances
of
Lane Kollen
As of December 2019

Date	Case	Jurisdict.	Party	Utility	Subject
2/88	10064	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, O&M expense, capital structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.

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6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8469	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.

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12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.
12/92	R-00922479	PA	Philadelphia Area Industrial Energy Users' Group	Philadelphia Electric Co.	OPEB expense.
1/93	8487	MD	Maryland Industrial Group	Baltimore Gas & Electric Co., Bethlehem Steel Corp.	OPEB expense, deferred fuel, CWIP in rate base.
1/93	39498	IN	PSI Industrial Group	PSI Energy, Inc.	Refunds due to over-collection of taxes on Marble Hill cancellation.
3/93	92-11-11	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co	OPEB expense.
3/93	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
3/93	93-01-EL-EFC	OH	Ohio Industrial Energy Consumers	Ohio Power Co.	Affiliate transactions, fuel.
3/93	EC92-21000 ER92-806-000	FERC	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
4/93	92-1464-EL-AIR	OH	Air Products Armco Steel Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
4/93	EC92-21000 ER92-806-000 (Rebuttal)	FERC	Louisiana Public Service Commission	Gulf States Utilities /Entergy Corp.	Merger.
9/93	93-113	KY	Kentucky Industrial Utility Customers	Kentucky Utilities	Fuel clause and coal contract refund.
9/93	92-490, 92-490A, 90-360-C	KY	Kentucky Industrial Utility Customers and Kentucky Attorney General	Big Rivers Electric Corp.	Disallowances and restitution for excessive fuel costs, illegal and improper payments, recovery of mine closure costs.
10/93	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	Revenue requirements, debt restructuring agreement, River Bend cost recovery.
1/94	U-20647	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
4/94	U-20647 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear and fossil unit performance, fuel costs, fuel clause principles and guidelines.
4/94	U-20647 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Audit and investigation into fuel clause costs.
5/94	U-20178	LA	Louisiana Public Service Commission Staff	Louisiana Power & Light Co.	Planning and quantification issues of least cost integrated resource plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/94	U-19904 Initial Post-Merger Earnings Review	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.

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Date	Case	Jurisdict.	Party	Utility	Subject
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.
9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
7/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.

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Date	Case	Jurisdict.	Party	Utility	Subject
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.
02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.

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Date	Case	Jurisdict.	Party	Utility	Subject
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.

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03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.
08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.

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02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U Panel with Victoria Taylor	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization, cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092 (Subdocket B)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.

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05/07	ER07-682-000 Supplemental Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.
11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.

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Date	Case	Jurisdict.	Party	Utility	Subject
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.
07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.

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09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, ELG v ASL depreciation procedures, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.
02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.

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Date	Case	Jurisdict.	Party	Utility	Subject
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E Answer	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.
09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.

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12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.
04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00548, 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.

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09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.
10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.

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04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.
08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.

Expert Testimony Appearances
of
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Date	Case	Jurisdict.	Party	Utility	Subject
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Rebuttal Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.
06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.

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11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.

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Date	Case	Jurisdict.	Party	Utility	Subject
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 03/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
07/16	16-057-01	UT	Office of Consumer Services	Dominion Resources, Inc. / Questar Corporation	Merger, risks, harms, benefits, accounting.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Next Era acquisition of Oncor; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.
08/17	17-0296-E-PC	WV	Public Service Commission of West Virginia Charleston	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Weather normalization, Rockport lease, O&M, incentive compensation, depreciation, income taxes.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/17	2017-00287	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Fuel cost allocation to native load customers.
12/17	2017-00321	KY	Attorney General	Duke Energy Kentucky (Electric)	Revenues, depreciation, income taxes, O&M, regulatory assets, environmental surcharge rider, FERC transmission cost reconciliation rider.
12/17	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics, tax abandonment loss.
01/18	2017-00349	KY	Kentucky Attorney General	Atmos Energy Kentucky	O&M expense, depreciation, regulatory assets and amortization, Annual Review Mechanism, Pipeline Replacement Program and Rider, affiliate expenses.
06/18	18-0047	OH	Ohio Energy Group	Ohio Electric Utilities	Tax Cuts and Jobs Act. Reduction in income tax expense; amortization of excess ADIT.
07/18	T-34695	LA	LPSC Staff	Crimson Gulf, LLC	Revenues, depreciation, income taxes, O&M, ADIT.
08/18	48325	TX	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX	Cities Served by TNMP	Texas-New Mexico Power Company	Revenues, payroll, income taxes, amortization of excess ADIT, capital structure.
08/18	2018-00146	KY	KIUC	Big Rivers Electric Corporation	Station Two contracts termination, regulatory asset, regulatory liability for savings
09/18 10/18	20170235-EI 20170236-EU Direct Supplemental Direct	FL	Office of Public Counsel	Florida Power & Light Company	FP&L acquisition of City of Vero Beach municipal electric utility systems.
09/18 10/18	2017-370-E Direct 2017-207, 305, 370-E Surrebuttal Supplemental Surrebuttal	SC	Office of Regulatory Staff	South Carolina Electric & Gas Company and Dominion Energy, Inc.	Recovery of Summer 2 and 3 new nuclear development costs, related regulatory liabilities, securitization, NOL carryforward and ADIT, TCJA savings, merger conditions and savings.
12/18	2018-00261	KY	Attorney General	Duke Energy Kentucky (Gas)	Revenues, O&M, regulatory assets, payroll, integrity management, incentive compensation, cash working capital.
01/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas & Electric Company	AFUDC v. CWIP in rate base, transmission and distribution plant additions, capitalization, revenues generation outage expense, depreciation rates and expenses, cost of debt.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/19	2018-00281	KY	Attorney General	Atmos Energy Group	AFUDC v. CWIP in rate base, ALG v. ELG depreciation rates, cash working capital, PRP Rider, forecast plant additions, forecast expenses, cost of debt, corporate cost allocation.
02/19 04/19	UD-18-17 Direct Surrebuttal and Cross-Answering	New Orleans	Crescent City Power Users Group	Entergy New Orleans, LLC	Post-test year adjustments, storm reserve fund, NOL ADIT, FIN48 ADIT, cash working capital, depreciation, amortization, capital structure, formula rate plans, purchased power rider.
03/19	2018-0358	KY	Attorney General	Kentucky American Water Company	Capital expenditures, cash working capital, payroll expense, incentive compensation, chemicals expense, electricity expense, water losses, rate case expense, excess deferred income taxes.
03/19	48929	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company LLC, Sempra Energy, Sharyland Distribution & Transmission Services, L.L.C.., Sharyland Utilities, L.P.	Sale, transfer, merger transactions, hold harmless and other regulatory conditions.
06/19	49421	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Prepaid pension asset, accrued OPEB liability, regulatory assets and liabilities, merger savings, storm damage expense, excess deferred income taxes.
07/19	49494	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Plant in service, prepaid pension asset, O&M, ROW costs, incentive compensation, self-insurance expense, excess deferred income taxes.
08/19	19-G-0309 19-G-0310	NY	New York City	National Grid	Depreciation rates, net negative salvage.
10/19	42315	GA	Atlanta Gas Light Company	Public Interest Advocacy Staff	Capital expenditures, O&M expense, prepaid pension asset, incentive compensation, merger savings, affiliate expenses, excess deferred income taxes.
10/19	45253	IN	Duke Energy Indiana	Office of Utility Consumer Counselor	Prepaid pension asset, inventories, regulatory assets and labilities, unbilled revenues, incentive compensation, income tax expense, affiliate charges, ADIT, riders.

EXHIBIT ____ (LK-2)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-014

REQUEST:

Refer to the electronic workpapers provided in response to Staff 1-54 and further to the worksheet tab WPB-6's which show the Accumulated Deferred Income Taxes ("ADIT") amounts by month for each account in total.

a. Provide another schedule in the same format for the months January 2018 through April 2019.

b. Provide the ADIT in accounts in accounts 190, 282, and 283 by temporary difference for each month January 2018 through March 2021.

RESPONSE:

a. Please see AG-DR-01-014(a) Attachment.

b. Please see AG-DR-01-014(b) Attachment. In this response, actual data has been used for January 2018 – September 2019 and forecasted data for October 2019 – March 2021.

PERSON RESPONSIBLE: John Panizza

DUKE ENERGY KENTUCKY, INC.
CERTAIN DEFERRED CREDITS AND ACCUMULATED DEFERRED INCOME TAXES
END OF MONTH BALANCES

LINE NO.	ACCOUNT NUMBER	DESCRIPTION	JANUARY 2018	FEBRUARY 2018	MARCH 2018	APRIL 2018	MAY 2018	JUNE 2018	JULY 2018	AUGUST 2018	SEPTEMBER 2018	OCTOBER 2018	NOVEMBER 2018	DECEMBER 2018	JANUARY 2019	FEBRUARY 2019	MARCH 2019	APRIL 2019
1	GAS																	
2	252050	Customers' Advances for Construction																
3																		
4	255	Investment Tax Credits:																
5		3% Credit																
6		4% Credit	(9,613)	(9,340)	(9,066)	(9,066)	(8,519)	(8,246)	(8,246)	(7,699)	(7,426)	(7,152)	(6,879)	(6,605)	(6,605)	(6,239)	(6,055)	(6,055)
7		10% Credit	(561,217)	(556,888)	(550,559)	(550,559)	(539,901)	(534,572)	(534,572)	(523,914)	(518,585)	(513,256)	(507,927)	(502,598)	(502,598)	(491,464)	(485,897)	(485,897)
8		30% Credit													0	0	0	0
9		Total Investment Tax Credits	(570,830)	(566,228)	(559,625)	(559,625)	(548,420)	(542,818)	(542,818)	(531,613)	(526,011)	(520,408)	(514,806)	(509,203)	(509,203)	(497,702)	(491,952)	(491,952)
10																		
11		Accumulated Deferred Income Taxes:																
12	190	Total Account 190	3,745,747	2,602,309	2,634,540	2,634,540	2,652,390	2,741,143	2,741,143	2,745,091	2,906,423	2,906,423	1,960,405	3,082,827	3,082,827	3,804,292	3,537,453	3,537,453
13																		
14	282	Account 282 - Other	(16,097,379)	(9,409,890)	(9,419,555)	(9,419,555)	(9,423,131)	(9,439,582)	(9,439,582)	(9,376,240)	(9,110,730)	(9,110,730)	(7,941,269)	(8,017,783)	(8,017,783)	(8,144,078)	(8,116,841)	(8,116,841)
15	282	Liberalized Depreciation	(77,183,754)	(50,864,047)	(51,013,218)	(51,013,218)	(50,719,508)	(50,865,211)	(50,865,211)	(52,905,157)	(53,687,020)	(53,687,020)	(54,130,164)	(55,559,734)	(55,559,734)	(55,873,726)	(56,103,757)	(56,103,757)
16	283	Total Account 283	(3,549,166)	(2,518,628)	(2,512,114)	(2,512,114)	(2,468,625)	(2,508,370)	(2,508,370)	(2,462,518)	(2,529,270)	(2,529,270)	(1,931,596)	(2,453,701)	(2,453,701)	(2,667,789)	(2,881,339)	(2,881,339)
17	283	Unrecovered Purchased Gas Cost																
18		Total Deferred Income Taxes	(93,184,552)	(60,190,257)	(60,310,347)	(60,310,347)	(59,958,874)	(60,072,020)	(60,072,020)	(61,998,824)	(62,420,597)	(62,420,597)	(62,042,645)	(63,028,572)	(63,028,572)	(63,081,301)	(63,566,484)	(63,566,484)
19																		
20		Regulatory Liability - Excess Deferred Taxes																
21	254	Protected	(31,380,810)	(31,350,036)	(31,319,261)	(31,288,486)	(31,257,711)	(31,226,937)	(31,196,162)	(32,101,501)	(32,070,726)	(32,039,952)	(32,122,328)	(32,091,553)	(32,091,553)	(32,030,004)	(31,999,229)	(31,968,454)
22	254	Unprotected	(335,138)	(365,913)	(396,688)	(427,463)	(458,238)	(489,012)	(519,787)	(517,786)	(548,561)	(579,335)	(410,182)	(409,937)	(409,937)	(404,865)	(402,329)	(399,793)
23		Total Regulatory Liability - Excess Deferred Taxes	(31,715,948)	(31,715,949)	(31,715,949)	(31,715,949)	(31,715,949)	(31,715,949)	(31,715,949)	(32,619,287)	(32,619,287)	(32,619,287)	(32,532,509)	(32,501,490)	(32,501,490)	(32,434,869)	(32,401,558)	(32,368,247)
24																		
25	ELECTRIC																	
26	252	Customers' Advances for Construction																
27																		
28	255	Investment Tax Credits:																
29		3% Credit																
30		4% Credit																
31		10% Credit	(12,542)	(10,694)	(9,711)	(9,711)	(7,823)	(6,875)	(6,875)	(4,985)	(4,041)	(4,041)	(2,152)	(1,207)	(1,207)	(1,136)	(1,100)	(1,100)
32		30% Credit	(3,253,589)	(3,253,589)	(3,253,589)	(3,253,589)	(3,253,589)	(3,253,589)	(3,253,589)	(3,017,307)	(3,017,307)	(3,017,307)	(3,017,307)	(3,017,307)	(3,017,307)	(3,017,307)	(3,017,307)	(3,017,307)
33		Total Investment Tax Credits	(3,266,131)	(3,264,283)	(3,263,300)	(3,263,300)	(3,261,412)	(3,260,464)	(3,260,464)	(3,022,292)	(3,021,348)	(3,021,348)	(3,019,459)	(3,018,514)	(3,018,514)	(3,018,443)	(3,018,407)	(3,018,407)
34																		
35		Accumulated Deferred Income Taxes:																
36	190	Total Account 190	7,840,092	8,978,456	9,413,311	9,413,311	9,532,436	9,742,815	9,742,815	11,882,523	10,200,704	10,200,704	10,655,883	18,884,841	18,884,841	19,859,880	19,350,057	19,350,057
37	281																	
38	282	Account 282 - Other	(83,842,391)	(56,088,408)	(58,948,991)	(58,948,991)	(57,832,950)	(58,953,349)	(58,953,349)	(60,904,088)	(61,982,826)	(61,982,826)	(73,434,606)	(79,934,583)	(79,934,583)	(86,220,835)	(88,101,492)	(88,101,492)
39	282	Liberalized Depreciation	(90,972,772)	(60,185,999)	(60,366,165)	(60,366,165)	(59,930,370)	(60,129,249)	(60,129,249)	(64,757,788)	(66,380,013)	(66,380,013)	(66,164,495)	(66,855,214)	(66,855,214)	(67,227,682)	(67,514,509)	(67,514,509)
40	283	Total Account 283	(24,827,004)	(19,143,611)	(20,504,969)	(20,504,969)	(20,351,219)	(20,134,248)	(20,134,248)	(19,896,049)	(19,734,789)	(19,734,789)	(19,802,796)	(18,456,360)	(18,456,360)	(17,998,090)	(18,239,361)	(18,239,361)
41		Total Deferred Income Taxes	(199,642,187)	(135,418,019)	(137,820,126)	(137,820,126)	(138,164,539)	(139,216,647)	(139,216,647)	(145,357,903)	(148,107,629)	(148,107,629)	(159,401,902)	(155,276,157)	(155,276,157)	(171,446,806)	(173,855,361)	(173,855,361)
42																		
43		Regulatory Liability - Excess Deferred Taxes																
44	254	Protected	(35,261,780)	(35,225,200)	(35,188,620)	(35,152,040)	(35,060,123)	(34,856,206)	(34,676,289)	(37,564,187)	(37,564,771)	(37,465,355)	(47,003,471)	(47,376,745)	(47,376,745)	(47,303,565)	(47,267,005)	(47,230,425)
45	254	Unprotected	(34,013,395)	(34,048,975)	(34,086,555)	(34,123,135)	(33,548,011)	(33,572,887)	(33,297,763)	(33,002,477)	(32,727,271)	(32,452,065)	(24,971,294)	(24,695,223)	(24,695,223)	(24,144,676)	(23,869,403)	(23,594,130)
46		Total Regulatory Liability - Excess Deferred Taxes	(69,275,175)	(69,275,175)	(69,275,175)	(69,275,175)	(68,608,134)	(68,541,093)	(68,174,052)	(70,566,564)	(70,292,042)	(69,917,420)	(71,974,765)	(72,071,968)	(72,071,968)	(71,448,261)	(71,136,408)	(70,824,554)
47																		
48	NON-UTILITY																	
49																		
50	255	Investment Tax Credits:																
51		3% Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
52		4% Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
53		10% Credit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
54		Total Investment Tax Credits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
55																		
56		Accumulated Deferred Income Taxes:																
57	190	Total Account 190	(15,003)	(10,225)	(304,635)	(304,635)	(301,041)	(240,890)	(240,890)	(240,890)	(456,185)	(456,185)	(468,195)	(201,973)	(201,973)	(201,973)	(201,973)	(201,973)
58	282	Account 282 - Other	(21,334)	3,062,105	3,012,107	3,012,107	2,934,963	2,908,139	2,908,139	2,855,603	2,820,557	2,820,557	2,741,195	2,702,270	2,702,270	2,602,546	2,546,113	2,546,113
59	282	Liberalized Depreciation	(46,973,464)	(31,763,895)	(31,598,070)	(31,598,070)	(30,688,601)	(30,734,932)	(30,734,932)	(30,407,195)	(30,243,327)	(30,243,327)	(29,915,590)	(29,846,713)	(29,846,713)	(29,534,807)	(29,378,855)	(29,378,855)
60	283	Total Account 283	(0)	-	-	-	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
61		Total Deferred Income Taxes	(49,010,401)	(28,712,019)	(28,580,598)	(28,580,598)	(28,254,579)	(28,067,683)	(28,067,683)	(27,792,482)	(27,878,965)	(27,878,965)	(27,830,591)	(27,346,415)	(27,346,415)	(27,134,235)	(27,034,714)	(27,034,714)
62																		
63		Regulatory Liability - Excess Deferred Taxes																
64	254	Protected																
65	254	Unprotected																
66		Total Regulatory Liability - Excess Deferred Taxes																

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

Code	Name	01.2018 Ending Balance	02.2018 Ending Balance	03.2018 Ending Balance	04.2018 Ending Balance	05.2018 Ending Balance	06.2018 Ending Balance	07.2018 Ending Balance	08.2018 Ending Balance
190001/2	ADIT: Prepaid: Taxes								
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit	89,917	104,661	112,033	112,033	126,777	134,149	134,149	148,893
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	537,775	537,775	537,775	537,775	537,775	537,775	537,775	537,775
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC	3,253,589	3,253,589	3,253,589	3,253,589	3,253,589	3,253,589	3,253,589	3,017,307
F_ITC_190002-411055	ITC Amortization - Non Utility	-	-	-	-	-	-	-	-
T11A02	Bad Debts - Tax over Book	82,749	56,311	51,370	51,370	53,164	51,480	51,480	54,519
T11B08	Surplus Materials Write-Off Asset	11,542	7,567	7,567	7,567	7,478	7,478	7,478	7,478
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	169,956	98,838	92,512	92,512	19,748	18,471	18,471	15,906
T15A22	Mark to Market - LT	2,838	1,860	1,860	1,860	1,838	1,838	1,838	1,838
T15A95	Unamortized Debt Premium	(2,812)	(1,290)	(1,013)	(1,013)	(454)	(11,303)	(11,303)	(10,829)
T15B07	Cash Flow Hedge - Reg Asset/Liab	178,108	116,762	343,060	343,060	339,012	345,042	345,042	345,042
T17A02	Accrued Vacation	723,300	474,175	474,175	474,175	454,522	448,176	448,176	446,879
T17A40	SEVERANCE RESERVE - LT	0	0	0	0	0	0	0	0
T17A54	MGP Sites	(84)	(55)	(0)	(0)	(0)	(0)	(0)	(0)
T18A02	Deferred Revenue	57,823	37,168	36,798	36,798	40,105	39,541	39,541	38,894
T19A22	Miscellaneous NC Taxable Income Adj - DTA	-	-	-	-	-	-	-	-
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-	-	-	-
T20A41	Rate Refunds	-	351,199	506,881	506,881	500,901	500,901	500,901	-
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	-	-	-	-	-	-	-	-
T20C02	Demand Side Management (DSM) Defer	(1,670,324)	(1,210,913)	(992,910)	(992,910)	(770,449)	(739,697)	(739,697)	(475,036)
T22A01	Emission Allowance Expense	(12,919)	(8,469)	(8,325)	(8,325)	(8,226)	(8,201)	(8,201)	(7,611)
T22A06	Operating Lease Obligation	-	-	-	-	-	-	-	-
T22A07	Charitable Contribution Carryover	-	-	-	-	-	-	-	40,695
T22A13	Lease Interest Expense	-	-	-	-	-	-	-	-
T22A28	Retirement Plan Expense - Underfunded	2,182,798	3,884,705	3,884,705	3,884,705	3,838,871	3,945,814	3,945,814	3,838,871
T22A29	Non-qualified Pension - Accrual	38,065	25,878	25,730	25,730	25,134	24,988	24,988	24,696
T22A56	Environmental Reserve	(26,440)	(17,333)	(17,333)	(17,333)	(17,129)	(17,129)	(17,129)	(10,263)
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	0	0	0	0	0	0	0	0
T22B13	ANNUAL INCENTIVE PLAN COMP	259,810	210,560	55,824	55,824	86,308	101,132	101,132	127,829
T22B15	PAYABLE 401 (K) MATCH	13,711	11,168	2,572	2,572	4,226	5,047	5,047	6,489
T22E02	OPEB Expense Accrual	1,477,052	859,432	859,489	859,489	849,195	850,999	850,999	852,338
T22E06	FAS 112 Medical Expenses Accrual	273,635	184,878	186,952	186,952	190,054	252,725	252,725	259,539
Total 190001/2		7,640,092	8,978,466	9,413,311	9,413,311	9,532,438	9,742,815	9,742,815	9,261,251
190155	Deferred Tax - NOL								
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs	-	-	-	-	-	-	-	2,601,372
Total 190155		-	-	-	-	-	-	-	2,601,372
190156	Deferred Tax_State NOLs								
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs	-	-	-	-	-	-	-	-
Total 190156		-	-	-	-	-	-	-	-
Account 190		7,640,092	8,978,466	9,413,311	9,413,311	9,532,438	9,742,815	9,742,815	11,862,623
282100/1	ADIT: PP&E								
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio	(341,627)	(341,627)	(341,627)	(341,627)	(341,627)	(341,627)	(341,627)	(316,817)
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS	495,985	495,985	495,985	495,985	512,932	512,932	512,932	512,932
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS	2,539,065	(3,800,185)	(3,800,185)	(3,800,185)	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)	283,207	283,207	283,207	283,207	283,207	283,207	283,207	283,207
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)	110,615	110,615	110,615	110,615	110,615	110,615	110,615	110,615
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)	(27,835)	(27,835)	(27,835)	(27,835)	(27,835)	(27,835)	(27,835)	(27,835)
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	816,314	820,529	822,637	822,637	826,852	828,960	828,960	833,175
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)	84,651	84,651	84,651	84,651	84,651	84,651	84,651	84,651
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)	1,283,980	1,298,089	1,305,143	1,305,143	1,319,252	1,326,306	1,326,306	1,340,414
T13A04	AFUDC Interest	(489,049)	(320,606)	(320,606)	(320,606)	(316,824)	(316,824)	(316,824)	(316,824)
T13A05	Repairs Allowed on Post ADR Prop	123,982	81,279	81,279	81,279	80,320	80,320	80,320	80,320
T13A08	Book Depreciation/Amortization	99,214,139	66,398,241	67,094,895	67,094,895	67,706,498	68,418,900	68,418,900	69,916,422
T13A09	Book Capital Lease Meters	(2,392,442)	(1,568,417)	(1,568,417)	(1,568,417)	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)
T13A10	Adjustment to Book Depreciation	3,416,017	2,228,184	2,234,244	2,234,244	2,202,320	1,827,997	1,827,997	2,155,576
T13A11	Lease Right of Use Asset	-	-	-	-	-	-	-	-
T13A12	Book Gain/Loss on Property	(1,309,038)	(858,168)	(858,168)	(858,168)	(848,043)	(848,043)	(848,043)	(848,043)

T13A14	Contributions in Aid (CIAC's)	543,533	356,466	371,806	371,806	360,704	360,704	360,704	383,079
T13A16	Cost of Removal	(600,467)	(393,649)	(393,649)	(393,649)	(389,005)	(389,005)	(389,005)	(389,005)
T13A18	Capitalized Hardware/Software	55,452	36,353	36,353	36,353	35,924	35,924	35,924	41,892
T13A19	After Tax ADC,M&E, ITC Temporary	(1,102,734)	(743,365)	(753,586)	(753,586)	(764,897)	(774,998)	(774,998)	(795,200)
T13A26	Tax Interest Capitalized	2,502,365	1,756,602	1,829,645	1,829,645	1,984,790	2,057,261	2,057,261	2,145,785
T13A28	Tax Depreciation/Amortization	(190,186,911)	(126,584,241)	(127,461,060)	(127,461,060)	(127,686,868)	(128,548,150)	(128,548,150)	(134,674,210)
T13A30	Tax Gains/Losses	(13,826,277)	(9,563,188)	(9,785,989)	(9,785,989)	(10,104,059)	(10,324,231)	(10,324,231)	(11,163,676)
T13A69	Casualty Loss	589,182	386,251	386,251	386,251	381,694	381,694	381,694	381,694
T13A75	Section 174 R&E Deduction	(1,132,320)	(742,317)	(742,317)	(742,317)	(733,559)	(733,559)	(733,559)	(1,542,204)
T13A77	Repairs 481(a) (Pursuant to 3115)	(21,040,429)	(13,793,506)	(13,793,506)	(13,793,506)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	57,046	38,568	39,133	39,133	40,824	41,473	41,473	41,904
T13B11	Excess Salvage	11,718	7,682	7,682	7,682	7,591	7,591	7,591	7,591
T13B18	Loss on ACRS	2,472,507	1,620,905	1,620,905	1,620,905	1,601,781	1,601,781	1,601,781	1,601,781
T13B20	Meters & Transformers	(197,884)	(129,727)	(129,727)	(129,727)	(128,196)	(128,196)	(128,196)	(128,196)
T13B23	Non-Cash Overhead Basis Adj	2,797,432	1,833,917	1,854,785	1,854,785	1,832,901	1,772,504	1,772,504	2,151,643
T13B26	Equipment Repairs - Annual Adj	(55,093,686)	(36,790,457)	(37,126,760)	(37,126,760)	(37,353,386)	(37,685,721)	(37,685,721)	(38,321,633)
T13B27	481(a) Fixed Asset Retirement	540,944	354,627	354,627	354,627	350,443	350,443	350,443	350,443
T13B31	Impairment of Plant Assets	457,845	300,150	300,150	300,150	296,609	296,609	296,609	289,131
T13B32	T & D Repairs 481(a) (pursuant to 3115)	(8,390,609)	(5,500,644)	(5,500,644)	(5,500,644)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)
T13B33	T & D Repairs - Annual Adj.	(9,313,749)	(6,316,018)	(6,736,396)	(6,736,396)	(7,072,335)	(7,280,044)	(7,280,044)	(7,774,226)
T13B43	Section 481(a) Casualty Losses	1,767,547	1,158,754	1,158,754	1,158,754	1,145,082	1,145,082	1,145,082	1,145,082
T13B44	Capitalized OH - Transportation	1,852	1,214	1,214	1,214	1,200	1,200	1,200	1,613
T22A16	Self Developed Software	(1,233,098)	(808,384)	(808,384)	(808,384)	(798,846)	(798,846)	(798,846)	(798,846)
TKY010	KY - Bonus Depreciation Adj	3,017,298	3,675,340	3,679,422	3,679,422	3,429,143	3,431,498	3,431,498	3,439,086
Total 282100/1		(193,423,275)	(129,763,115)	(130,759,465)	(130,759,465)	(131,041,414)	(133,756,066)	(133,756,066)	(140,153,116)
283100/1	ADIT: Other								
T15A24	Loss on Reacquired Debt-Amort	(365,657)	(231,888)	(227,974)	(227,974)	(217,550)	(213,683)	(213,683)	(205,948)
T15B02	Reg Asset/Liab Def Revenue	471,875	253,790	(416,386)	(416,386)	(977,842)	(515,724)	(515,724)	(398,831)
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	1	1	1	1	0	0	0	0
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	-	-	-	-	-	-	-	-
T15B18	Reg Asset Storm Damage Recovery	(1,890,125)	(1,239,112)	(1,239,112)	(1,239,112)	(1,204,083)	(938,776)	(938,776)	(897,960)
T15B26	Reg Asset - Rate Case Expense	(169,128)	(116,768)	(1,723,742)	(1,723,742)	(161,984)	(126,752)	(126,752)	(126,300)
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	(8,042,403)	(6,232,328)	(6,204,042)	(6,204,042)	(6,074,939)	(6,046,987)	(6,046,987)	(5,991,083)
T15B35	Regulatory Asset - Carbon Management	(692,539)	(454,009)	(466,620)	(466,620)	(452,801)	(357,256)	(357,256)	(340,640)
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	(18,687)	(13,344)	(13,281)	(13,281)	(13,000)	(12,937)	(12,937)	(12,813)
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	(659,086)	(424,298)	(420,407)	(420,407)	(407,759)	(403,915)	(403,915)	(396,226)
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	1,128,755	849,779	846,652	846,652	830,482	827,392	827,392	821,212
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	4,399	2,884	2,884	2,884	2,850	2,850	2,850	2,850
T15B43	Reg Asset - Transition from MISO to PJM	6,296,741	4,086,384	4,106,490	4,106,490	4,021,966	4,043,122	4,043,122	4,006,619
T15B45	Reg Asset - Plant Related Retirements	-	-	-	-	-	-	-	-
T15B69	Reg Asset Opt Out Tariff IT Modifications	(59,526)	(39,653)	(39,653)	(39,653)	(38,554)	(30,065)	(30,065)	(28,759)
T15B77	Non-AMI Meters Retired Early - NBV	-	-	-	-	(1,528,730)	(1,549,547)	(1,549,547)	(1,549,547)
T15B81	Reg Asset_Liab - Outage Costs	-	-	-	-	-	(304,446)	(304,446)	(271,910)
T17A01	Vacation Carryover - Reg Asset	(394,722)	(258,768)	(258,768)	(258,768)	(255,715)	(255,715)	(255,715)	(255,715)
T20A38	Regulatory Asset - Deferred Plant Costs	(19,842,078)	(13,405,842)	(12,517,599)	(12,517,599)	(11,937,329)	(11,525,977)	(11,525,977)	(11,388,509)
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-	-	-	-
T22A15	Operating Lease Deferral	-	-	-	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	(594,823)	(1,920,440)	(1,933,410)	(1,933,410)	(1,936,232)	(2,055,992)	(2,055,992)	(1,992,649)
T22B16	Miscellaneous NC Taxable Income Adj - DTL	(0)	-	(0)	(0)	(0)	(669,842)	(669,842)	(669,842)
Total 283100/1		(33,982,031)	(25,422,837)	(26,915,940)	(26,915,940)	(27,005,981)	(26,821,227)	(26,821,227)	(26,290,502)
Total Deferred Income Taxes		**(219,765,214)**	**(146,207,486)**	**(148,262,094)**	**(148,262,094)**	**(148,514,956)**	**(150,834,479)**	**(150,834,479)**	**(154,580,995)**

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

		ACTUAL							
Code	Name	09.2018 Ending Balance	10.2018 Ending Balance	11.2018 Ending Balance	12.2018 Ending Balance	01.2019 Ending Balance	02.2019 Ending Balance	03.2019 Ending Balance	04.2019 Ending Balance
190001/2	ADIT: Prepaid: Taxes								
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit	156,265	156,265	171,009	178,381	178,381	193,567	201,160	201,160
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	879,520	879,520	879,520	879,520	879,520	879,520	879,520	879,520
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC	3,017,307	3,017,307	3,017,307	3,017,307	3,017,307	3,017,307	3,017,307	3,017,307
F_ITC_190002-411055	ITC Amortization - Non Utility	-	-	-	-	-	-	-	-
T11A02	Bad Debts - Tax over Book	50,676	50,676	53,710	51,217	51,217	52,977	67,297	67,297
T11B08	Surplus Materials Write-Off Asset	10,783	10,783	11,683	7,478	7,478	7,478	7,478	7,478
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	14,619	14,619	12,033	10,735	10,735	8,132	6,825	6,825
T15A22	Mark to Market - LT	1,838	1,838	1,838	1,838	1,838	1,838	1,838	1,838
T15A95	Unamortized Debt Premium	(10,592)	(10,592)	(10,118)	(9,882)	(9,882)	(9,408)	(9,171)	(9,171)
T15B07	Cash Flow Hedge - Reg Asset/Liab	488,332	488,332	488,332	301,067	301,067	301,067	276,611	276,611
T17A02	Accrued Vacation	446,879	446,879	446,702	463,883	463,883	459,576	450,847	450,847
T17A40	SEVERANCE RESERVE - LT	0	0	0	89,242	89,242	58,706	27,272	27,272
T17A54	MGP Sites	(0)	(0)	(0)	(0)	(0)	-	-	-
T18A02	Deferred Revenue	63,917	63,917	63,186	61,017	61,017	60,993	60,377	60,377
T19A22	Miscellaneous NC Taxable Income Adj - DTA	484,036	484,036	-	476,297	476,297	476,297	476,297	476,297
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-	-	-	-
T20A41	Rate Refunds	-	-	-	(121,934)	(121,934)	(121,934)	(121,934)	(121,934)
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	-	-	218,756	355,390	355,390	831,304	283,227	283,227
T20C02	Demand Side Management (DSM) Defer	(693,479)	(693,479)	65,086	(271,152)	(271,152)	153,914	355,024	355,024
T22A01	Emission Allowance Expense	(6,579)	(6,579)	(6,579)	(6,184)	(6,184)	(6,184)	(6,082)	(6,082)
T22A06	Operating Lease Obligation	-	-	-	-	-	2,362,253	2,355,467	2,355,467
T22A07	Charitable Contribution Carryover	6,004	6,004	(1,705)	40,695	40,695	40,695	30,521	30,521
T22A13	Lease Interest Expense	-	-	-	-	-	8,554	8,532	8,532
T22A28	Retirement Plan Expense - Underfunded	4,008,268	4,008,268	3,838,871	2,967,941	2,967,941	2,736,090	3,034,315	3,034,315
T22A29	Non-qualified Pension - Accrual	24,550	24,550	24,258	23,281	23,281	23,063	22,953	22,953
T22A56	Environmental Reserve	(10,263)	(10,263)	(10,263)	(10,263)	(10,263)	(17,098)	(17,098)	(17,098)
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	0	0	0	0	0	0	0	0
T22B13	ANNUAL INCENTIVE PLAN COMP	142,284	142,284	174,704	184,411	184,411	149,224	2,263	2,263
T22B15	PAYABLE 401 (K) MATCH	7,269	7,269	8,544	10,141	10,141	11,195	1,807	1,807
T22E02	OPEB Expense Accrual	855,956	855,956	904,551	759,434	759,434	760,257	765,232	765,232
T22E06	FAS 112 Medical Expenses Accrual	263,115	263,115	269,733	272,776	272,776	278,295	281,055	281,055
Total 190001/2		10,200,704	10,200,704	10,621,158	9,732,639	9,732,639	12,717,678	12,458,942	12,458,942
190155	Deferred Tax - NOL								
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs	-	-	-	7,117,477	7,117,477	7,117,477	6,856,390	6,856,390
Total 190155		-	-	-	7,117,477	7,117,477	7,117,477	6,856,390	6,856,390
190156	Deferred Tax_State NOLs								
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs	-	-	34,725	34,725	34,725	34,725	34,725	34,725
Total 190156		-	-	34,725	34,725	34,725	34,725	34,725	34,725
Account 190		10,200,704	10,200,704	10,655,883	16,884,841	16,884,841	19,869,880	19,350,057	19,350,057
282100/1	ADIT: PP&E								
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio	(316,817)	(316,817)	(316,817)	(316,817)	(316,817)	(316,817)	(316,817)	(316,817)
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS	512,932	512,932	512,932	512,932	512,932	512,932	512,932	512,932
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)	283,207	283,207	283,207	283,207	283,207	283,207	283,207	283,207
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)	110,615	110,615	110,615	110,615	110,615	110,615	110,615	110,615
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)	(27,835)	(27,835)	(38,900)	(38,900)	(38,900)	(38,900)	(38,900)	(38,900)
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	835,283	835,283	829,355	830,540	830,540	832,911	834,097	834,097
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)	84,651	84,651	84,651	84,651	84,651	84,651	84,651	84,651
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)	1,347,469	1,347,469	1,361,577	1,368,632	1,368,632	1,382,741	1,389,795	1,389,795
T13A04	AFUDC Interest	(316,824)	(316,824)	(316,824)	(316,824)	(316,824)	(316,824)	(316,824)	(316,824)
T13A05	Repairs Allowed on Post ADR Prop	80,320	80,320	80,320	80,320	80,320	80,320	80,320	80,320
T13A08	Book Depreciation/Amortization	70,670,014	70,670,014	72,189,264	73,187,203	73,187,203	74,748,941	75,414,218	75,414,218
T13A09	Book Capital Lease Meters	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)
T13A10	Adjustment to Book Depreciation	1,951,247	1,951,247	1,930,024	1,937,979	1,937,979	1,916,756	1,887,847	1,887,847
T13A11	Lease Right of Use Asset	-	-	-	-	-	(2,366,107)	(2,356,949)	(2,356,949)
T13A12	Book Gain/Loss on Property	(848,043)	(848,043)	(848,043)	(848,043)	(848,043)	(848,043)	(848,043)	(848,043)

T13A14	Contributions in Aid (CIAC's)	363,929	363,929	683,413	685,046	685,046	752,654	776,552	776,552
T13A16	Cost of Removal	(389,005)	(389,005)	(389,005)	(389,005)	(389,005)	(885,587)	(1,103,316)	(1,103,316)
T13A18	Capitalized Hardware/Software	41,892	41,892	41,892	41,892	41,892	41,892	41,892	41,892
T13A19	After Tax ADC,M&E, ITC Temporary	(805,302)	(805,302)	(824,025)	(834,011)	(834,011)	(853,982)	(863,968)	(863,968)
T13A26	Tax Interest Capitalized	2,196,138	2,196,138	2,307,278	2,361,572	2,361,572	2,504,777	2,585,935	2,585,935
T13A28	Tax Depreciation/Amortization	(137,050,028)	(137,050,028)	(138,353,782)	(140,072,418)	(140,072,418)	(141,976,623)	(142,928,726)	(142,928,726)
T13A30	Tax Gains/Losses	(11,383,850)	(11,383,850)	(11,836,024)	(16,906,187)	(16,906,187)	(17,122,205)	(17,230,214)	(17,230,214)
T13A69	Casualty Loss	381,694	381,694	381,694	381,694	381,694	381,694	381,694	381,694
T13A75	Section 174 R&E Deduction	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)
T13A77	Repairs 481(a) (Pursuant to 3115)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	42,801	42,801	44,593	45,489	45,489	47,536	48,536	48,536
T13B11	Excess Salvage	7,591	7,591	7,591	7,591	7,591	7,591	7,591	7,591
T13B18	Loss on ACRS	1,601,781	1,601,781	1,601,781	1,601,781	1,601,781	1,601,781	1,601,781	1,601,781
T13B20	Meters & Transformers	(128,196)	(128,196)	(128,196)	(128,196)	(128,196)	(128,196)	(128,196)	(128,196)
T13B23	Non-Cash Overhead Basis Adj	2,118,784	2,118,784	2,118,784	2,075,744	2,075,744	2,075,744	2,132,912	2,132,912
T13B26	Equipment Repairs - Annual Adj	(39,152,470)	(39,152,470)	(52,798,970)	(54,356,790)	(54,356,790)	(57,472,429)	(59,030,249)	(59,030,249)
T13B27	481(a) Fixed Asset Retirement	350,443	350,443	350,443	350,443	350,443	350,443	350,443	350,443
T13B31	Impairment of Plant Assets	289,131	289,131	289,131	289,131	289,131	289,131	289,131	289,131
T13B32	T & D Repairs 481(a) (pursuant to 3115)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)
T13B33	T & D Repairs - Annual Adj.	(8,293,500)	(8,293,500)	(6,775,145)	(6,835,380)	(6,835,380)	(7,121,271)	(7,264,217)	(7,264,217)
T13B43	Section 481(a) Casualty Losses	1,145,082	1,145,082	1,145,082	1,145,082	1,145,082	1,145,082	1,145,082	1,145,082
T13B44	Capitalized OH - Transportation	1,613	1,613	1,613	1,613	1,613	1,613	1,613	1,613
T22A16	Self Developed Software	(798,846)	(798,846)	(798,846)	(798,846)	(798,846)	(798,846)	(798,846)	(798,846)
TKY010	KY - Bonus Depreciation Adj	4,106,636	4,106,636	4,855,589	5,023,841	5,023,841	5,030,479	5,033,798	5,033,798
Total 282100/1		(145,321,200)	(145,321,200)	(159,033,192)	(166,280,755)	(166,280,755)	(172,970,482)	(175,172,250)	(175,172,250)
283100/1	ADIT: Other								
T15A24	Loss on Reacquired Debt-Amort	(206,256)	(206,256)	(198,521)	(198,829)	(198,829)	(190,922)	(191,143)	(191,143)
T15B02	Reg Asset/Liab Def Revenue	(625,774)	(625,774)	(281,813)	(180,787)	(180,787)	(45,508)	(134,772)	(134,772)
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	0	0	0	0	0	1	1	1
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	-	-	-	119,633	119,633	-	143,923	143,923
T15B18	Reg Asset Storm Damage Recovery	(877,552)	(877,552)	(836,736)	(816,327)	(816,327)	(775,511)	(755,103)	(755,103)
T15B28	Reg Asset - Rate Case Expense	(123,569)	(123,569)	(111,973)	(109,242)	(109,242)	(103,780)	(72,360)	(72,360)
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	(5,963,130)	(5,963,130)	(5,907,226)	(5,710,335)	(5,710,335)	(5,667,034)	(5,645,383)	(5,645,383)
T15B35	Regulatory Asset - Carbon Management	(344,794)	(344,794)	(340,640)	(332,332)	(332,332)	(315,715)	(307,407)	(307,407)
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	(12,750)	(12,750)	(12,626)	(11,733)	(11,733)	(11,605)	(11,542)	(11,542)
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	(392,382)	(392,382)	(384,693)	(380,849)	(380,849)	(371,222)	(366,409)	(366,409)
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	818,122	818,122	811,942	945,269	945,269	936,082	931,488	931,488
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	2,850	2,850	2,850	2,850	2,850	2,850	2,850	2,850
T15B43	Reg Asset - Transition from MISO to PJM	4,028,372	4,028,372	3,693,140	3,714,895	3,714,895	3,679,229	3,701,816	3,701,816
T15B45	Reg Asset - Plant Related Retirements	-	-	(377,371)	(299,541)	(299,541)	(261,977)	(261,977)	(261,977)
T15B69	Reg Asset Opt Out Tariff IT Modifications	(28,105)	(28,105)	(26,799)	(26,146)	(26,146)	(24,840)	(24,162)	(24,162)
T15B77	Non-AMI Meters Retired Early - NBV	(1,366,441)	(1,366,441)	(1,366,441)	(1,337,532)	(1,337,532)	(1,337,532)	(1,308,623)	(1,308,623)
T15B81	Reg Asset_Liab - Outage Costs	(356,590)	(356,590)	(464,686)	(599,240)	(599,240)	(600,275)	(600,326)	(600,326)
T17A01	Vacation Carryover - Reg Asset	(255,715)	(255,715)	(255,715)	(255,292)	(255,292)	(255,292)	(255,292)	(255,292)
T20A38	Regulatory Asset - Deferred Plant Costs	(11,308,337)	(11,308,337)	(11,166,512)	(11,085,536)	(11,085,536)	(10,942,100)	(10,870,930)	(10,870,930)
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-	-	-	-
T22A15	Operating Lease Deferral	-	-	-	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	(2,156,897)	(2,156,897)	(2,013,134)	(1,323,960)	(1,323,960)	(1,141,610)	(1,464,585)	(1,464,585)
T22B16	Miscellaneous NC Taxable Income Adj - DTL	(565,841)	(565,841)	(565,841)	(571,327)	(571,327)	(571,327)	(749,426)	(749,426)
Total 283100/1		(26,371,849)	(26,371,849)	(25,143,906)	(23,832,040)	(23,832,040)	(23,486,309)	(23,772,042)	(23,772,042)
Total Deferred Income Taxes		**(161,492,344)**	**(161,492,344)**	**(173,521,214)**	**(173,227,954)**	**(173,227,954)**	**(176,586,911)**	**(179,594,235)**	**(179,594,235)**

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

BS Rate	4.9685%
Fed	21.0000%
FBOS	-1.0434%

Code	Name	05.2019 Ending Balance	Jun 2019 Ending Balance	Jul 2019 Ending Balance	Aug 2019 Ending Balance	Sept 2019 Ending Balance	Oct 2019 Current Activity	Oct 2019 Ending Balance	Nov 2019 Current Activity	Nov 2019 Ending Balance
190001/2	ADIT: Prepaid: Taxes									
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit	216,346	223,939	223,939	239,125	246,718		246,718		246,718
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	879,520	879,520	879,520	879,520	879,520	1,893	881,413	1,893	883,305
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC	3,017,307	3,017,307	3,017,307	3,017,307	3,017,307		3,017,307		3,017,307
F_ITC_190002-411055	ITC Amortization - Non Utility	-	-	-	-	-		-		-
T11A02	Bad Debts - Tax over Book	70,274	75,586	75,586	79,711	70,057	-	70,057	-	70,057
T11B08	Surplus Materials Write-Off Asset	7,478	7,478	7,478	7,477	7,477	-	7,477	-	7,477
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	4,200	(13,993)	(13,993)	(13,993)	(13,993)	-	(13,993)	-	(13,993)
T15A22	Mark to Market - LT	1,838	1,838	1,838	1,838	1,838	-	1,838	-	1,838
T15A95	Unamortized Debt Premium	(8,697)	(8,460)	(8,460)	(7,986)	(7,749)	-	(7,749)	-	(7,749)
T15B07	Cash Flow Hedge - Reg Asset/Liab	276,611	78,233	78,233	78,233	61,022	-	61,022	-	61,022
T17A02	Accrued Vacation	450,495	446,016	446,016	445,950	445,950	-	445,950	-	445,950
T17A40	SEVERANCE RESERVE - LT	25,513	24,728	24,728	23,443	22,943	-	22,943	-	22,943
T17A54	MGP Sites	-	-	-	-	-	-	-	-	-
T18A02	Deferred Revenue	104,406	107,330	107,330	106,098	131,851	-	131,851	-	131,851
T19A22	Miscellaneous NC Taxable Income Adj - DTA	476,297	1,209,037	1,209,037	1,209,037	1,304,620	-	1,304,620	-	1,304,620
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-	-	-	-	-
T20A41	Rate Refunds	(121,934)	(121,934)	(121,934)	(121,934)	(121,934)	-	(121,934)	-	(121,934)
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	663,911	557,233	557,233	(15,388)	(21,807)	-	(21,807)	-	(21,807)
T20C02	Demand Side Management (DSM) Defer	632,806	(218,842)	(218,842)	(140,719)	(201,950)	-	(201,950)	-	(201,950)
T22A01	Emission Allowance Expense	(6,082)	(5,893)	(5,893)	(5,893)	(5,646)	-	(5,646)	-	(5,646)
T22A06	Operating Lease Obligation	2,341,678	2,334,728	2,334,728	2,320,603	2,315,338	-	2,315,338	-	2,315,338
T22A07	Charitable Contribution Carryover	30,521	20,347	20,347	20,347	4,205	-	4,205	-	4,205
T22A13	Lease Interest Expense	8,487	8,464	8,464	8,417	8,398	-	8,398	-	8,398
T22A28	Retirement Plan Expense - Underfunded	2,802,464	3,978,885	3,978,885	3,752,008	4,513,032	2,331	4,515,363	2,331	4,517,693
T22A29	Non-qualified Pension - Accrual	22,735	22,626	22,626	22,408	22,298	-	22,298	-	22,298
T22A56	Environmental Reserve	(17,098)	(17,098)	(17,098)	(17,098)	(17,098)	-	(17,098)	-	(17,098)
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	0	0	0	0	0	-	0	-	0
T22B13	ANNUAL INCENTIVE PLAN COMP	17,620	26,374	26,374	48,157	57,694	-	57,694	-	57,694
T22B15	PAYABLE 401 (K) MATCH	2,840	3,341	3,341	4,605	5,141	-	5,141	-	5,141
T22E02	OPEB Expense Accrual	767,856	772,331	772,331	777,489	783,357	-	783,357	-	783,357
T22E06	FAS 112 Medical Expenses Accrual	248,832	215,447	215,447	219,701	220,889	-	220,889	-	220,889
Total 190001/2		12,916,225	13,624,570	13,624,570	12,938,465	13,729,480	4,223	13,733,703	4,223	13,737,927
190155	Deferred Tax - NOL									
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs	6,856,390	6,856,390	6,856,390	6,856,390	6,369,016		6,369,016	-	6,369,016
Total 190155		6,856,390	6,856,390	6,856,390	6,856,390	6,369,016	-	6,369,016	-	6,369,016
190156	Deferred Tax_State NOLs									
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs	34,725	34,725	34,725	34,725	34,725		34,725	-	34,725
Total 190156		34,725	34,725	34,725	34,725	34,725	-	34,725	-	34,725
Account 190		**19,807,340**	**20,515,685**	**20,515,685**	**19,829,580**	**20,133,221**	**4,223**	**20,137,445**	**4,223**	**20,141,668**
282100/1	ADIT: PP&E									
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E	2,861,323	2,861,323	2,861,323	2,861,323	2,861,323		2,861,323		2,861,323
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio	(316,817)	(316,817)	(316,817)	(316,817)	(316,817)		(316,817)		(316,817)
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E	5,818,993	5,818,993	5,818,993	5,818,993	5,818,993		5,818,993		5,818,993
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS	512,932	512,932	512,932	512,932	512,932		512,932		512,932
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)	(3,907,073)		(3,907,073)		(3,907,073)
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)	283,207	283,207	283,207	283,207	283,207		283,207		283,207
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)	110,615	110,615	110,615	110,615	110,615		110,615		110,615
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)	(38,900)	(38,900)	(38,900)	(38,900)	(38,900)		(38,900)		(38,900)
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	836,468	837,653	837,653	840,024	841,210	2,054	843,263	2,054	845,317
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)	84,651	84,651	84,651	84,651	84,651		84,651		84,651
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)	1,403,904	1,410,958	1,410,958	1,425,066	1,432,121		1,432,121		1,432,121
T13A04	AFUDC Interest	(316,824)	(316,824)	(316,824)	(316,824)	(316,824)	-	(316,824)	-	(316,824)
T13A05	Repairs Allowed on Post ADR Prop	80,320	80,320	80,320	80,320	80,320	-	80,320	-	80,320
T13A08	Book Depreciation/Amortization	76,998,236	77,607,524	77,607,524	79,152,909	80,047,386	881,638	80,929,024	882,969	81,811,994
T13A09	Book Capital Lease Meters	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)	(1,549,912)	-	(1,549,912)	-	(1,549,912)
T13A10	Adjustment to Book Depreciation	1,887,847	1,708,363	1,708,363	1,708,363	1,677,791	-	1,677,791	-	1,677,791
T13A11	Lease Right of Use Asset	(2,338,564)	(2,329,338)	(2,329,338)	(2,310,815)	(2,303,399)	-	(2,303,399)	-	(2,303,399)
T13A12	Book Gain/Loss on Property	(848,043)	(848,043)	(848,043)	(848,043)	(848,043)	-	(848,043)	-	(848,043)

T13A14	Contributions in Aid (CIAC's)	854,172	937,216	937,216	1,127,685	1,333,247	-	1,333,247	-	1,333,247
T13A16	Cost of Removal	(1,787,416)	(2,117,547)	(2,117,547)	(2,823,434)	(3,113,275)	-	(3,113,275)	-	(3,113,275)
T13A18	Capitalized Hardware/Software	41,892	41,892	41,892	41,892	41,892	-	41,892	-	41,892
T13A19	After Tax ADC,M&E, ITC Temporary	(877,672)	(886,404)	(886,404)	(903,868)	(912,600)	(8,749)	(921,350)	(8,749)	(930,099)
T13A26	Tax Interest Capitalized	2,668,145	2,698,854	2,698,854	2,777,379	2,822,525	46,102	2,868,627	53,615	2,922,242
T13A28	Tax Depreciation/Amortization	(144,832,932)	(145,016,466)	(145,016,466)	(146,664,482)	(146,227,149)	(976,509)	(147,203,659)	(976,509)	(148,180,168)
T13A30	Tax Gains/Losses	(17,446,231)	(17,554,240)	(17,554,240)	(17,770,258)	(17,878,267)	(179,040)	(18,057,307)	(194,975)	(18,252,282)
T13A69	Casualty Loss	381,694	381,694	381,694	381,694	381,694	-	381,694	-	381,694
T13A75	Section 174 R&E Deduction	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)	(1,542,204)	-	(1,542,204)	-	(1,542,204)
T13A77	Repairs 481(a) (Pursuant to 3115)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)	(13,630,762)	-	(13,630,762)	-	(13,630,762)
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	50,813	71,623	71,623	74,117	75,438	-	75,438	-	75,438
T13B11	Excess Salvage	7,591	7,591	7,591	7,591	7,591	-	7,591	-	7,591
T13B18	Loss on ACRS	1,601,781	1,601,781	1,601,781	1,601,781	1,601,781	-	1,601,781	-	1,601,781
T13B20	Meters & Transformers	(128,196)	(128,196)	(128,196)	(128,196)	(128,196)	-	(128,196)	-	(128,196)
T13B23	Non-Cash Overhead Basis Adj	2,132,912	2,142,166	2,142,166	2,142,166	2,149,239	-	2,149,239	-	2,149,239
T13B26	Equipment Repairs - Annual Adj	(62,145,888)	(63,703,708)	(63,703,708)	(66,819,347)	(62,849,400)	(1,557,820)	(64,407,219)	(1,557,820)	(65,965,039)
T13B27	481(a) Fixed Asset Retirement	350,443	350,443	350,443	350,443	350,443	-	350,443	-	350,443
T13B31	Impairment of Plant Assets	289,131	289,131	289,131	289,131	289,131	-	289,131	-	289,131
T13B32	T & D Repairs 481(a) (pursuant to 3115)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)	(5,435,744)	-	(5,435,744)	-	(5,435,744)
T13B33	T & D Repairs - Annual Adj.	(7,550,108)	(7,693,053)	(7,693,053)	(7,978,945)	(7,571,917)	(142,946)	(7,714,863)	(142,946)	(7,857,809)
T13B43	Section 481(a) Casualty Losses	1,145,082	1,145,082	1,145,082	1,145,082	1,145,082	-	1,145,082	-	1,145,082
T13B44	Capitalized OH - Transportation	1,613	1,613	1,613	1,613	1,613	-	1,613	-	1,613
T22A16	Self Developed Software	(798,846)	(798,846)	(798,846)	(798,846)	(798,846)	-	(798,846)	-	(798,846)
TKY010	KY - Bonus Depreciation Adj	5,040,436	5,043,755	5,043,755	5,050,393	5,053,712	-	5,053,712	-	5,053,712
Total 282100/1		(160,047,930)	(181,436,239)	(181,436,239)	(185,630,168)	(179,601,424)	(1,935,270)	(162,300,660)	(1,942,361)	(164,243,021)
283100/1	ADIT: Other									
T15A24	Loss on Reacquired Debt-Amort	(183,236)	(184,273)	(184,273)	(178,353)	(177,841)	2,899	(174,942)	2,899	(172,042)
T15B02	Reg Asset/Liab Def Revenue	(790,560)	(312,004)	(312,004)	(210,406)	(333,341)	-	(333,341)	-	(333,341)
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	1	1	1	1	1	-	1	-	1
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	143,923	59,345	59,345	59,345	59,994	-	59,994	-	59,994
T15B18	Reg Asset Storm Damage Recovery	(714,287)	(693,878)	(693,878)	(653,062)	(632,654)	-	(632,654)	-	(632,654)
T15B28	Reg Asset - Rate Case Expense	(66,898)	(80,258)	(80,258)	(74,796)	(71,943)	-	(71,943)	-	(71,943)
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	(5,602,082)	(6,451,382)	(6,451,382)	(6,388,589)	(6,937,333)	-	(6,937,333)	-	(6,937,333)
T15B35	Regulatory Asset - Carbon Management	(290,790)	(390,486)	(390,486)	(382,178)	(378,023)	-	(378,023)	-	(378,023)
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	(11,415)	(11,351)	(11,351)	(11,224)	(11,160)	-	(11,160)	-	(11,160)
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	(356,782)	(351,968)	(351,968)	(342,341)	(337,527)	-	(337,527)	-	(337,527)
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	922,302	917,708	917,708	908,521	903,928	-	903,928	-	903,928
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	2,850	2,850	2,850	2,850	2,850	-	2,850	-	2,850
T15B43	Reg Asset - Transition from MISO to PJM	3,666,482	3,689,070	3,689,070	3,654,454	3,677,275	-	3,677,275	-	3,677,275
T15B45	Reg Asset - Plant Related Retirements	(0)	(0)	(0)	(0)	(0)	-	(0)	-	(0)
T15B69	Reg Asset Opt Out Tariff IT Modifications	(22,856)	(22,203)	(22,203)	(20,897)	(20,244)	-	(20,244)	-	(20,244)
T15B77	Non-AMI Meters Retired Early - NBV	(1,308,623)	(1,109,125)	(1,109,125)	(1,109,125)	(1,086,157)	-	(1,086,157)	-	(1,086,157)
T15B81	Reg Asset_Liab - Outage Costs	(600,343)	(600,343)	(600,343)	(600,343)	(600,343)	-	(600,343)	-	(600,343)
T17A01	Vacation Carryover - Reg Asset	(255,292)	(255,292)	(255,292)	(255,292)	(255,292)	-	(255,292)	-	(255,292)
T20A38	Regulatory Asset - Deferred Plant Costs	(10,747,107)	(10,599,023)	(10,599,023)	(10,453,128)	(10,371,611)	93,261	(10,278,349)	93,261	(10,185,088)
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-	-	-	-	-
T22A15	Operating Lease Deferral	(9,250)	(11,504)	(11,504)	-	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	(1,282,235)	(1,605,210)	(1,605,210)	(1,422,860)	(1,745,834)	-	(1,745,834)	-	(1,745,834)
T22B16	Miscellaneous NC Taxable Income Adj - DTL	(749,426)	(602,251)	(602,251)	(602,251)	(608,743)	-	(608,743)	-	(608,743)
Total 283100/1		(18,255,623)	(23,784,270)	(23,784,270)	(22,704,375)	(23,159,110)	96,161	(18,827,839)	96,161	(18,731,678)
Total Deferred Income Taxes		**(158,496,213)**	**(184,704,825)**	**(184,704,825)**	**(188,504,963)**	**(182,627,313)**	**(1,834,886)**	**(160,991,055)**	**(1,841,977)**	**(162,833,032)**

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

Code	Name	Dec 2019 Current Activity	Dec 2019 Ending Balance	Jan 2020 Current Activity	Jan 2020 Ending Balance	Feb 2020 Current Activity
190001/2	ADIT: Prepaid: Taxes					
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit		246,718		246,718	
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	1,893	885,198	1,949	887,147	1,949
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC		3,017,307		3,017,307	
F_ITC_190002-411055	ITC Amortization - Non Utility		-		-	
T11A02	Bad Debts - Tax over Book	-	70,057	-	70,057	-
T11B08	Surplus Materials Write-Off Asset	-	7,477	-	7,477	-
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	-	(13,993)	-	(13,993)	-
T15A22	Mark to Market - LT	-	1,838	-	1,838	-
T15A95	Unamortized Debt Premium	-	(7,749)	-	(7,749)	-
T15B07	Cash Flow Hedge - Reg Asset/Liab	-	61,022	-	61,022	-
T17A02	Accrued Vacation	-	445,950	-	445,950	-
T17A40	SEVERANCE RESERVE - LT	-	22,943	-	22,943	-
T17A54	MGP Sites	-	-	-	-	-
T18A02	Deferred Revenue	-	131,851	-	131,851	-
T19A22	Miscellaneous NC Taxable Income Adj - DTA	-	1,304,620	-	1,304,620	-
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-
T20A41	Rate Refunds	-	(121,934)	-	(121,934)	-
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	-	(21,807)	-	(21,807)	-
T20C02	Demand Side Management (DSM) Defer	-	(201,950)	-	(201,950)	-
T22A01	Emission Allowance Expense	-	(5,646)	-	(5,646)	-
T22A06	Operating Lease Obligation	-	2,315,338	-	2,315,338	-
T22A07	Charitable Contribution Carryover	-	4,205	-	4,205	-
T22A13	Lease Interest Expense	-	8,398	-	8,398	-
T22A28	Retirement Plan Expense - Underfunded	2,331	4,520,024	2,197	4,522,221	2,197
T22A29	Non-qualified Pension - Accrual	-	22,298	-	22,298	-
T22A56	Environmental Reserve	-	(17,098)	-	(17,098)	-
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	-	0	-	0	-
T22B13	ANNUAL INCENTIVE PLAN COMP	-	57,694	-	57,694	-
T22B15	PAYABLE 401 (K) MATCH	-	5,141	-	5,141	-
T22E02	OPEB Expense Accrual	-	783,357	-	783,357	-
T22E06	FAS 112 Medical Expenses Accrual	-	220,889	-	220,889	-
Total 190001/2		4,223	13,742,150	4,147	13,746,297	4,147
190155	Deferred Tax - NOL					
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs		6,369,016	-	6,369,016	
Total 190155		-	6,369,016	-	6,369,016	-
190156	Deferred Tax_State NOLs					
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs		34,725		34,725	
Total 190156		-	34,725	-	34,725	-
Account 190		4,223	20,145,891	4,147	20,150,038	4,147
282100/1	ADIT: PP&E					
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E		2,861,323		2,861,323	
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio		(316,817)		(316,817)	
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E		5,818,993		5,818,993	
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS		512,932		512,932	
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS		(3,907,073)		(3,907,073)	
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)		283,207		283,207	
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)		110,615		110,615	
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)		(38,900)		(38,900)	
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	2,054	847,371	2,054	849,425	2,054
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)		84,651		84,651	
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)		1,432,121		1,432,121	
T13A04	AFUDC Interest	-	(316,824)	-	(316,824)	-
T13A05	Repairs Allowed on Post ADR Prop	-	80,320	-	80,320	-
T13A08	Book Depreciation/Amortization	883,748	82,695,742	910,063	83,605,805	910,547
T13A09	Book Capital Lease Meters	-	(1,549,912)	-	(1,549,912)	-
T13A10	Adjustment to Book Depreciation	-	1,677,791	-	1,677,791	-
T13A11	Lease Right of Use Asset	-	(2,303,399)	-	(2,303,399)	-
T13A12	Book Gain/Loss on Property	-	(848,043)	-	(848,043)	-

T13A14	Contributions in Aid (CIAC's)	-	1,333,247	-	1,333,247	-
T13A16	Cost of Removal	-	(3,113,275)	-	(3,113,275)	-
T13A18	Capitalized Hardware/Software	-	41,892	-	41,892	-
T13A19	After Tax ADC,M&E, ITC Temporary	(8,749)	(938,849)	(8,749)	(947,598)	(8,749)
T13A26	Tax Interest Capitalized	30,600	2,952,841	32,686	2,985,527	36,097
T13A28	Tax Depreciation/Amortization	(976,509)	(149,156,677)	(901,209)	(150,057,886)	(901,209)
T13A30	Tax Gains/Losses	(1,514,582)	(19,766,864)	(188,169)	(19,955,032)	(131,727)
T13A69	Casualty Loss	-	381,694	-	381,694	-
T13A75	Section 174 R&E Deduction	-	(1,542,204)	-	(1,542,204)	-
T13A77	Repairs 481(a) (Pursuant to 3115)	-	(13,630,762)	-	(13,630,762)	-
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	-	75,438	-	75,438	-
T13B11	Excess Salvage	-	7,591	-	7,591	-
T13B18	Loss on ACRS	-	1,601,781	-	1,601,781	-
T13B20	Meters & Transformers	-	(128,196)	-	(128,196)	-
T13B23	Non-Cash Overhead Basis Adj	-	2,149,239	-	2,149,239	-
T13B26	Equipment Repairs - Annual Adj	(1,557,820)	(67,522,859)	(1,557,820)	(69,080,679)	(1,557,820)
T13B27	481(a) Fixed Asset Retirement	-	350,443	-	350,443	-
T13B31	Impairment of Plant Assets	-	289,131	-	289,131	-
T13B32	T & D Repairs 481(a) (pursuant to 3115)	-	(5,435,744)	-	(5,435,744)	-
T13B33	T & D Repairs - Annual Adj.	(142,946)	(8,000,754)	(146,934)	(8,147,688)	(146,934)
T13B43	Section 481(a) Casualty Losses	-	1,145,082	-	1,145,082	-
T13B44	Capitalized OH - Transportation	-	1,613	-	1,613	-
T22A16	Self Developed Software	-	(798,846)	-	(798,846)	-
TKY010	KY - Bonus Depreciation Adj	-	5,053,712		5,053,712	
Total 282100/1		(3,284,204)	(167,527,225)	(1,858,078)	(169,385,303)	(1,797,741)
283100/1	ADIT: Other					
T15A24	Loss on Reacquired Debt-Amort	2,899	(169,143)	2,899	(166,243)	2,899
T15B02	Reg Asset/Liab Def Revenue	-	(333,341)	-	(333,341)	-
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	-	1	-	1	-
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	-	59,994	-	59,994	-
T15B18	Reg Asset Storm Damage Recovery	-	(632,654)	-	(632,654)	-
T15B28	Reg Asset - Rate Case Expense	-	(71,943)	-	(71,943)	-
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	-	(6,937,333)	-	(6,937,333)	-
T15B35	Regulatory Asset - Carbon Management	-	(378,023)	-	(378,023)	-
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	-	(11,160)	-	(11,160)	-
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	-	(337,527)	-	(337,527)	-
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	-	903,928	-	903,928	-
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	-	2,850	-	2,850	-
T15B43	Reg Asset - Transition from MISO to PJM	-	3,677,275	-	3,677,275	-
T15B45	Reg Asset - Plant Related Retirements	-	(0)	-	(0)	-
T15B69	Reg Asset Opt Out Tariff IT Modifications	-	(20,244)	-	(20,244)	-
T15B77	Non-AMI Meters Retired Early - NBV	-	(1,086,157)	-	(1,086,157)	-
T15B81	Reg Asset_Liab - Outage Costs	-	(600,343)	-	(600,343)	-
T17A01	Vacation Carryover - Reg Asset	-	(255,292)	-	(255,292)	-
T20A38	Regulatory Asset - Deferred Plant Costs	93,261	(10,091,826)	93,261	(9,998,565)	93,261
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-
T22A15	Operating Lease Deferral	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	-	(1,745,834)	-	(1,745,834)	-
T22B16	Miscellaneous NC Taxable Income Adj - DTL	-	(608,743)	-	(608,743)	-
Total 283100/1		96,161	(18,635,517)	96,161	(18,539,356)	96,161
Total Deferred Income Taxes		**(3,183,820)**	**(166,016,851)**	**(1,757,770)**	**(167,774,622)**	**(1,697,433)**

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

Code	Name	Feb 2020 Ending Balance	Mar 2020 Current Activity	Mar 2020 Ending Balance	FORECAST Apr 2020 Current Activity	Apr 2020 Ending Balance	May 2020 Current Activity	May 2020 Ending Balance	Jun 2020 Current Activity	Jun 2020 Ending Balance	Jul 2020 Current Activity
190001/2	ADIT: Prepaid: Taxes										
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit	246,718		246,718		246,718		246,718		246,718	
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	889,096	1,949	891,046	1,949	892,995	1,949	894,945	1,949	896,894	1,949
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC	3,017,307		3,017,307		3,017,307		3,017,307		3,017,307	
F_ITC_190002-411055	ITC Amortization - Non Utility	-		-		-		-		-	
T11A02	Bad Debts - Tax over Book	70,057	-	70,057	-	70,057	-	70,057	-	70,057	-
T11B08	Surplus Materials Write-Off Asset	7,477	-	7,477	-	7,477	-	7,477	-	7,477	-
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	(13,993)	-	(13,993)	-	(13,993)	-	(13,993)	-	(13,993)	-
T15A22	Mark to Market - LT	1,838	-	1,838	-	1,838	-	1,838	-	1,838	-
T15A95	Unamortized Debt Premium	(7,749)	-	(7,749)	-	(7,749)	-	(7,749)	-	(7,749)	-
T15B07	Cash Flow Hedge - Reg Asset/Liab	61,022	-	61,022	-	61,022	-	61,022	-	61,022	-
T17A02	Accrued Vacation	445,950	-	445,950	-	445,950	-	445,950	-	445,950	-
T17A40	SEVERANCE RESERVE - LT	22,943	-	22,943	-	22,943	-	22,943	-	22,943	-
T17A54	MGP Sites	-	-	-	-	-	-	-	-	-	-
T18A02	Deferred Revenue	131,851	-	131,851	-	131,851	-	131,851	-	131,851	-
T19A22	Miscellaneous NC Taxable Income Adj - DTA	1,304,620	-	1,304,620	-	1,304,620	-	1,304,620	-	1,304,620	-
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-	-	-	-	-	-
T20A41	Rate Refunds	(121,934)	-	(121,934)	-	(121,934)	-	(121,934)	-	(121,934)	-
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	(21,807)	-	(21,807)	-	(21,807)	-	(21,807)	-	(21,807)	-
T20C02	Demand Side Management (DSM) Defer	(201,950)	-	(201,950)	-	(201,950)	-	(201,950)	-	(201,950)	-
T22A01	Emission Allowance Expense	(5,646)	-	(5,646)	-	(5,646)	-	(5,646)	-	(5,646)	-
T22A06	Operating Lease Obligation	2,315,338	-	2,315,338	-	2,315,338	-	2,315,338	-	2,315,338	-
T22A07	Charitable Contribution Carryover	4,205	-	4,205	-	4,205	-	4,205	-	4,205	-
T22A13	Lease Interest Expense	8,398	-	8,398	-	8,398	-	8,398	-	8,398	-
T22A28	Retirement Plan Expense - Underfunded	4,524,419	2,197	4,526,616	2,197	4,528,814	2,197	4,531,011	2,197	4,533,209	2,197
T22A29	Non-qualified Pension - Accrual	22,298	-	22,298	-	22,298	-	22,298	-	22,298	-
T22A56	Environmental Reserve	(17,098)	-	(17,098)	-	(17,098)	-	(17,098)	-	(17,098)	-
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	0	-	0	-	0	-	0	-	0	-
T22B13	ANNUAL INCENTIVE PLAN COMP	57,694	-	57,694	-	57,694	-	57,694	-	57,694	-
T22B15	PAYABLE 401 (K) MATCH	5,141	-	5,141	-	5,141	-	5,141	-	5,141	-
T22E02	OPEB Expense Accrual	783,357	-	783,357	-	783,357	-	783,357	-	783,357	-
T22E06	FAS 112 Medical Expenses Accrual	220,889	-	220,889	-	220,889	-	220,889	-	220,889	-
Total 190001/2		13,750,444	4,147	13,754,590	4,147	13,758,737	4,147	13,762,884	4,147	13,767,031	4,147
190155	Deferred Tax - NOL										
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs	6,369,016		6,369,016		6,369,016		6,369,016		6,369,016	
Total 190155		6,369,016	-	6,369,016	-	6,369,016	-	6,369,016	-	6,369,016	-
190156	Deferred Tax_State NOLs										
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs	34,725		34,725		34,725		34,725		34,725	
Total 190156		34,725	-	34,725	-	34,725	-	34,725	-	34,725	-
Account 190		20,154,185	4,147	20,158,332	4,147	20,162,478	4,147	20,166,625	4,147	20,170,772	4,147
282100/1	ADIT: PP&E										
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E	2,861,323		2,861,323		2,861,323		2,861,323		2,861,323	
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio	(316,817)		(316,817)		(316,817)		(316,817)		(316,817)	
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E	5,818,993		5,818,993		5,818,993		5,818,993		5,818,993	
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS	512,932		512,932		512,932		512,932		512,932	
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS	(3,907,073)		(3,907,073)		(3,907,073)		(3,907,073)		(3,907,073)	
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)	283,207		283,207		283,207		283,207		283,207	
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)	110,615		110,615		110,615		110,615		110,615	
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)	(38,900)		(38,900)		(38,900)		(38,900)		(38,900)	
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	851,478	2,054	853,532	2,054	855,586	2,054	857,640	2,054	859,694	2,054
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)	84,651		84,651		84,651		84,651		84,651	
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)	1,432,121		1,432,121		1,432,121		1,432,121		1,432,121	
T13A04	AFUDC Interest	(316,824)	-	(316,824)	-	(316,824)	-	(316,824)	-	(316,824)	-
T13A05	Repairs Allowed on Post ADR Prop	80,320	-	80,320	-	80,320	-	80,320	-	80,320	-
T13A08	Book Depreciation/Amortization	84,516,353	910,708	85,427,061	921,746	86,348,807	922,275	87,271,082	933,591	88,204,673	949,258
T13A09	Book Capital Lease Meters	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-
T13A10	Adjustment to Book Depreciation	1,677,791	-	1,677,791	-	1,677,791	-	1,677,791	-	1,677,791	-
T13A11	Lease Right of Use Asset	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-
T13A12	Book Gain/Loss on Property	(848,043)	-	(848,043)	-	(848,043)	-	(848,043)	-	(848,043)	-

T13A14	Contributions in Aid (CIAC's)	1,333,247	-	1,333,247	-	1,333,247	-	1,333,247	-	1,333,247	-
T13A16	Cost of Removal	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-
T13A18	Capitalized Hardware/Software	41,892	-	41,892	-	41,892	-	41,892	-	41,892	-
T13A19	After Tax ADC,M&E, ITC Temporary	(956,348)	(8,749)	(965,097)	(8,749)	(973,847)	(8,749)	(982,596)	(8,749)	(991,346)	(8,749)
T13A26	Tax Interest Capitalized	3,021,624	39,186	3,060,810	43,614	3,104,424	34,534	3,138,958	29,170	3,168,128	33,135
T13A28	Tax Depreciation/Amortization	(150,959,095)	(901,209)	(151,860,305)	(901,209)	(152,761,514)	(901,209)	(153,662,724)	(901,209)	(154,563,933)	(901,209)
T13A30	Tax Gains/Losses	(20,086,759)	(180,000)	(20,266,759)	(162,935)	(20,429,694)	(158,881)	(20,588,575)	(180,791)	(20,769,366)	(207,623)
T13A69	Casualty Loss	381,694	-	381,694	-	381,694	-	381,694	-	381,694	-
T13A75	Section 174 R&E Deduction	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-
T13A77	Repairs 481(a) (Pursuant to 3115)	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	75,438	-	75,438	-	75,438	-	75,438	-	75,438	-
T13B11	Excess Salvage	7,591	-	7,591	-	7,591	-	7,591	-	7,591	-
T13B18	Loss on ACRS	1,601,781	-	1,601,781	-	1,601,781	-	1,601,781	-	1,601,781	-
T13B20	Meters & Transformers	(128,196)	-	(128,196)	-	(128,196)	-	(128,196)	-	(128,196)	-
T13B23	Non-Cash Overhead Basis Adj	2,149,239	-	2,149,239	-	2,149,239	-	2,149,239	-	2,149,239	-
T13B26	Equipment Repairs - Annual Adj	(70,638,498)	(1,557,820)	(72,196,318)	(1,557,820)	(73,754,138)	(1,557,820)	(75,311,957)	(1,557,820)	(76,869,777)	(1,557,820)
T13B27	481(a) Fixed Asset Retirement	350,443	-	350,443	-	350,443	-	350,443	-	350,443	-
T13B31	Impairment of Plant Assets	289,131	-	289,131	-	289,131	-	289,131	-	289,131	-
T13B32	T & D Repairs 481(a) (pursuant to 3115)	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-
T13B33	T & D Repairs - Annual Adj.	(8,294,621)	(146,934)	(8,441,555)	(146,934)	(8,588,488)	(146,934)	(8,735,422)	(146,934)	(8,882,355)	(146,934)
T13B43	Section 481(a) Casualty Losses	1,145,082	-	1,145,082	-	1,145,082	-	1,145,082	-	1,145,082	-
T13B44	Capitalized OH - Transportation	1,613	-	1,613	-	1,613	-	1,613	-	1,613	-
T22A16	Self Developed Software	(798,846)	-	(798,846)	-	(798,846)	-	(798,846)	-	(798,846)	-
TKY010	KY - Bonus Depreciation Adj	5,053,712	-	5,053,712	-	5,053,712	-	5,053,712	-	5,053,712	-
Total 282100/1		(171,183,044)	(1,842,764)	(173,025,809)	(1,810,233)	(174,836,042)	(1,814,730)	(176,650,772)	(1,830,688)	(178,481,460)	(1,837,889)
283100/1	ADIT: Other										
T15A24	Loss on Reacquired Debt-Amort	(163,344)	2,899	(160,445)	2,899	(157,545)	2,899	(154,646)	2,328	(152,317)	2,328
T15B02	Reg Asset/Liab Def Revenue	(333,341)	-	(333,341)	-	(333,341)	-	(333,341)	-	(333,341)	-
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	1	-	1	-	1	-	1	-	1	-
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	59,994	-	59,994	-	59,994	-	59,994	-	59,994	-
T15B18	Reg Asset Storm Damage Recovery	(632,654)	-	(632,654)	-	(632,654)	-	(632,654)	-	(632,654)	-
T15B28	Reg Asset - Rate Case Expense	(71,943)	-	(71,943)	-	(71,943)	-	(71,943)	-	(71,943)	-
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-
T15B35	Regulatory Asset - Carbon Management	(378,023)	-	(378,023)	-	(378,023)	-	(378,023)	-	(378,023)	-
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	(11,160)	-	(11,160)	-	(11,160)	-	(11,160)	-	(11,160)	-
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	(337,527)	-	(337,527)	-	(337,527)	-	(337,527)	-	(337,527)	-
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	903,928	-	903,928	-	903,928	-	903,928	-	903,928	-
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	2,850	-	2,850	-	2,850	-	2,850	-	2,850	-
T15B43	Reg Asset - Transition from MISO to PJM	3,677,275	-	3,677,275	-	3,677,275	-	3,677,275	-	3,677,275	-
T15B45	Reg Asset - Plant Related Retirements	(0)	-	(0)	-	(0)	-	(0)	-	(0)	-
T15B69	Reg Asset Opt Out Tariff IT Modifications	(20,244)	-	(20,244)	-	(20,244)	-	(20,244)	-	(20,244)	-
T15B77	Non-AMI Meters Retired Early - NBV	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-
T15B81	Reg Asset_Liab - Outage Costs	(600,343)	-	(600,343)	-	(600,343)	-	(600,343)	-	(600,343)	-
T17A01	Vacation Carryover - Reg Asset	(255,292)	-	(255,292)	-	(255,292)	-	(255,292)	-	(255,292)	-
T20A38	Regulatory Asset - Deferred Plant Costs	(9,905,303)	93,261	(9,812,042)	93,261	(9,718,780)	93,261	(9,625,519)	93,261	(9,532,257)	93,261
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-	-	-	-	-	-
T22A15	Operating Lease Deferral	-	-	-	-	-	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-
T22B16	Miscellaneous NC Taxable Income Adj - DTL	(608,743)	-	(608,743)	-	(608,743)	-	(608,743)	-	(608,743)	-
Total 283100/1		(18,443,195)	96,161	(18,347,034)	96,161	(18,250,874)	96,161	(18,154,713)	95,590	(18,059,123)	95,590
Total Deferred Income Taxes		**(169,472,055)**	**(1,742,457)**	**(171,214,512)**	**(1,709,926)**	**(172,924,437)**	**(1,714,422)**	**(174,638,859)**	**(1,730,951)**	**(176,369,811)**	**(1,738,152)**

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

Code	Name	Jul 2020 Ending Balance	Aug 2020 Current Activity	Aug 2020 Ending Balance	Sep 2020 Current Activity	Sep 2020 Ending Balance	Oct 2020 Current Activity	Oct 2020 Ending Balance	Nov 2020 Current Activity	Nov 2020 Ending Balance	Dec 2020 Current Activity
190001/2	ADIT: Prepaid: Taxes										
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit	246,718		246,718		246,718		246,718		246,718	
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	898,843	1,949	900,793	1,949	902,742	1,949	904,692	1,949	906,641	1,949
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC	3,017,307		3,017,307		3,017,307		3,017,307		3,017,307	
F_ITC_190002-411055	ITC Amortization - Non Utility	-		-		-		-		-	
T11A02	Bad Debts - Tax over Book	70,057	-	70,057	-	70,057	-	70,057	-	70,057	-
T11B08	Surplus Materials Write-Off Asset	7,477	-	7,477	-	7,477	-	7,477	-	7,477	-
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	(13,993)	-	(13,993)	-	(13,993)	-	(13,993)	-	(13,993)	-
T15A22	Mark to Market - LT	1,838	-	1,838	-	1,838	-	1,838	-	1,838	-
T15A95	Unamortized Debt Premium	(7,749)	-	(7,749)	-	(7,749)	-	(7,749)	-	(7,749)	-
T15B07	Cash Flow Hedge - Reg Asset/Liab	61,022	-	61,022	-	61,022	-	61,022	-	61,022	-
T17A02	Accrued Vacation	445,950	-	445,950	-	445,950	-	445,950	-	445,950	-
T17A40	SEVERANCE RESERVE - LT	22,943	-	22,943	-	22,943	-	22,943	-	22,943	-
T17A54	MGP Sites	-	-	-	-	-	-	-	-	-	-
T18A02	Deferred Revenue	131,851	-	131,851	-	131,851	-	131,851	-	131,851	-
T19A22	Miscellaneous NC Taxable Income Adj - DTA	1,304,620	-	1,304,620	-	1,304,620	-	1,304,620	-	1,304,620	-
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-	-	-	-	-	-
T20A41	Rate Refunds	(121,934)	-	(121,934)	-	(121,934)	-	(121,934)	-	(121,934)	-
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	(21,807)	-	(21,807)	-	(21,807)	-	(21,807)	-	(21,807)	-
T20C02	Demand Side Management (DSM) Defer	(201,950)	-	(201,950)	-	(201,950)	-	(201,950)	-	(201,950)	-
T22A01	Emission Allowance Expense	(5,646)	-	(5,646)	-	(5,646)	-	(5,646)	-	(5,646)	-
T22A06	Operating Lease Obligation	2,315,338	-	2,315,338	-	2,315,338	-	2,315,338	-	2,315,338	-
T22A07	Charitable Contribution Carryover	4,205	-	4,205	-	4,205	-	4,205	-	4,205	-
T22A13	Lease Interest Expense	8,398	-	8,398	-	8,398	-	8,398	-	8,398	-
T22A28	Retirement Plan Expense - Underfunded	4,535,406	2,197	4,537,603	2,197	4,539,801	2,197	4,541,998	2,197	4,544,196	2,197
T22A29	Non-qualified Pension - Accrual	22,298	-	22,298	-	22,298	-	22,298	-	22,298	-
T22A56	Environmental Reserve	(17,098)	-	(17,098)	-	(17,098)	-	(17,098)	-	(17,098)	-
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	0	-	0	-	0	-	0	-	0	-
T22B13	ANNUAL INCENTIVE PLAN COMP	57,694	-	57,694	-	57,694	-	57,694	-	57,694	-
T22B15	PAYABLE 401 (K) MATCH	5,141	-	5,141	-	5,141	-	5,141	-	5,141	-
T22E02	OPEB Expense Accrual	783,357	-	783,357	-	783,357	-	783,357	-	783,357	-
T22E06	FAS 112 Medical Expenses Accrual	220,889	-	220,889	-	220,889	-	220,889	-	220,889	-
Total 190001/2		13,771,178	4,147	13,775,324	4,147	13,779,471	4,147	13,783,618	4,147	13,787,765	4,147
190155	Deferred Tax - NOL										
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs	6,369,016		6,369,016		6,369,016		6,369,016		6,369,016	
Total 190155		6,369,016	-	6,369,016	-	6,369,016	-	6,369,016	-	6,369,016	-
190156	Deferred Tax_State NOLs										
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs	34,725		34,725		34,725		34,725		34,725	
Total 190156		34,725	-	34,725	-	34,725	-	34,725	-	34,725	-
Account 190		20,174,919	4,147	20,179,066	4,147	20,183,213	4,147	20,187,359	4,147	20,191,506	4,147
282100/1	ADIT: PP&E										
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E	2,861,323		2,861,323		2,861,323		2,861,323		2,861,323	
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio	(316,817)		(316,817)		(316,817)		(316,817)		(316,817)	
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E	5,818,993		5,818,993		5,818,993		5,818,993		5,818,993	
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS	512,932		512,932		512,932		512,932		512,932	
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS	(3,907,073)		(3,907,073)		(3,907,073)		(3,907,073)		(3,907,073)	
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)	283,207		283,207		283,207		283,207		283,207	
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)	110,615		110,615		110,615		110,615		110,615	
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)	(38,900)		(38,900)		(38,900)		(38,900)		(38,900)	
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	861,747	2,054	863,801	2,054	865,855	2,054	867,909	2,054	869,962	2,054
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)	84,651		84,651		84,651		84,651		84,651	
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)	1,432,121		1,432,121		1,432,121		1,432,121		1,432,121	
T13A04	AFUDC Interest	(316,824)	-	(316,824)	-	(316,824)	-	(316,824)	-	(316,824)	-
T13A05	Repairs Allowed on Post ADR Prop	80,320	-	80,320	-	80,320	-	80,320	-	80,320	-
T13A08	Book Depreciation/Amortization	89,153,931	950,227	90,104,158	950,344	91,054,502	956,620	92,011,122	956,707	92,967,829	956,470
T13A09	Book Capital Lease Meters	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-
T13A10	Adjustment to Book Depreciation	1,677,791	-	1,677,791	-	1,677,791	-	1,677,791	-	1,677,791	-
T13A11	Lease Right of Use Asset	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-
T13A12	Book Gain/Loss on Property	(848,043)	-	(848,043)	-	(848,043)	-	(848,043)	-	(848,043)	-

T13A14	Contributions in Aid (CIAC's)	1,333,247	-	1,333,247	-	1,333,247	-	1,333,247	-	1,333,247	-
T13A16	Cost of Removal	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-
T13A18	Capitalized Hardware/Software	41,892	-	41,892	-	41,892	-	41,892	-	41,892	-
T13A19	After Tax ADC,M&E, ITC Temporary	(1,000,095)	(8,749)	(1,008,845)	(8,749)	(1,017,594)	(8,749)	(1,026,344)	(8,749)	(1,035,093)	(8,749)
T13A26	Tax Interest Capitalized	3,201,262	38,660	3,239,922	42,635	3,282,557	47,031	3,329,589	52,107	3,381,696	27,585
T13A28	Tax Depreciation/Amortization	(155,465,143)	(901,209)	(156,366,352)	(901,209)	(157,267,561)	(901,209)	(158,168,771)	(901,209)	(159,069,980)	(901,209)
T13A30	Tax Gains/Losses	(20,976,989)	(179,221)	(21,156,210)	(156,149)	(21,312,359)	(175,774)	(21,488,133)	(183,513)	(21,671,646)	(240,152)
T13A69	Casualty Loss	381,694	-	381,694	-	381,694	-	381,694	-	381,694	-
T13A75	Section 174 R&E Deduction	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-
T13A77	Repairs 481(a) (Pursuant to 3115)	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	75,438	-	75,438	-	75,438	-	75,438	-	75,438	-
T13B11	Excess Salvage	7,591	-	7,591	-	7,591	-	7,591	-	7,591	-
T13B18	Loss on ACRS	1,601,781	-	1,601,781	-	1,601,781	-	1,601,781	-	1,601,781	-
T13B20	Meters & Transformers	(128,196)	-	(128,196)	-	(128,196)	-	(128,196)	-	(128,196)	-
T13B23	Non-Cash Overhead Basis Adj	2,149,239	-	2,149,239	-	2,149,239	-	2,149,239	-	2,149,239	-
T13B26	Equipment Repairs - Annual Adj	(78,427,597)	(1,557,820)	(79,985,416)	(1,557,820)	(81,543,236)	(1,557,820)	(83,101,056)	(1,557,820)	(84,658,875)	(1,557,820)
T13B27	481(a) Fixed Asset Retirement	350,443	-	350,443	-	350,443	-	350,443	-	350,443	-
T13B31	Impairment of Plant Assets	289,131	-	289,131	-	289,131	-	289,131	-	289,131	-
T13B32	T & D Repairs 481(a) (pursuant to 3115)	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-
T13B33	T & D Repairs - Annual Adj.	(9,029,289)	(146,934)	(9,176,222)	(146,934)	(9,323,156)	(146,934)	(9,470,090)	(146,934)	(9,617,023)	(146,934)
T13B43	Section 481(a) Casualty Losses	1,145,082	-	1,145,082	-	1,145,082	-	1,145,082	-	1,145,082	-
T13B44	Capitalized OH - Transportation	1,613	-	1,613	-	1,613	-	1,613	-	1,613	-
T22A16	Self Developed Software	(798,846)	-	(798,846)	-	(798,846)	-	(798,846)	-	(798,846)	-
TKY010	KY - Bonus Depreciation Adj	5,053,712	-	5,053,712	-	5,053,712	-	5,053,712	-	5,053,712	-
Total 282100/1		(180,319,349)	(1,802,993)	(182,122,342)	(1,775,828)	(183,898,170)	(1,784,781)	(185,682,951)	(1,787,357)	(187,470,308)	(1,868,755)
283100/1	ADIT: Other										
T15A24	Loss on Reacquired Debt-Amort	(149,989)	2,328	(147,661)	2,328	(145,332)	2,328	(143,004)	2,056	(140,948)	1,784
T15B02	Reg Asset/Liab Def Revenue	(333,341)	-	(333,341)	-	(333,341)	-	(333,341)	-	(333,341)	-
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	1	-	1	-	1	-	1	-	1	-
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	59,994	-	59,994	-	59,994	-	59,994	-	59,994	-
T15B18	Reg Asset Storm Damage Recovery	(632,654)	-	(632,654)	-	(632,654)	-	(632,654)	-	(632,654)	-
T15B28	Reg Asset - Rate Case Expense	(71,943)	-	(71,943)	-	(71,943)	-	(71,943)	-	(71,943)	-
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-
T15B35	Regulatory Asset - Carbon Management	(378,023)	-	(378,023)	-	(378,023)	-	(378,023)	-	(378,023)	-
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	(11,160)	-	(11,160)	-	(11,160)	-	(11,160)	-	(11,160)	-
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	(337,527)	-	(337,527)	-	(337,527)	-	(337,527)	-	(337,527)	-
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	903,928	-	903,928	-	903,928	-	903,928	-	903,928	-
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	2,850	-	2,850	-	2,850	-	2,850	-	2,850	-
T15B43	Reg Asset - Transition from MISO to PJM	3,677,275	-	3,677,275	-	3,677,275	-	3,677,275	-	3,677,275	-
T15B45	Reg Asset - Plant Related Retirements	(0)	-	(0)	-	(0)	-	(0)	-	(0)	-
T15B69	Reg Asset Opt Out Tariff IT Modifications	(20,244)	-	(20,244)	-	(20,244)	-	(20,244)	-	(20,244)	-
T15B77	Non-AMI Meters Retired Early - NBV	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-
T15B81	Reg Asset_Liab - Outage Costs	(600,343)	-	(600,343)	-	(600,343)	-	(600,343)	-	(600,343)	-
T17A01	Vacation Carryover - Reg Asset	(255,292)	-	(255,292)	-	(255,292)	-	(255,292)	-	(255,292)	-
T20A38	Regulatory Asset - Deferred Plant Costs	(9,438,996)	93,261	(9,345,734)	93,261	(9,252,473)	93,261	(9,159,212)	93,261	(9,065,950)	93,261
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-	-	-	-	-	-
T22A15	Operating Lease Deferral	-	-	-	-	-	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-
T22B16	Miscellaneous NC Taxable Income Adj - DTL	(608,743)	-	(608,743)	-	(608,743)	-	(608,743)	-	(608,743)	-
Total 283100/1		(17,963,533)	95,590	(17,867,943)	95,590	(17,772,353)	95,590	(17,676,763)	95,318	(17,581,446)	95,045
Total Deferred Income Taxes		**(178,107,963)**	**(1,703,256)**	**(179,811,219)**	**(1,676,091)**	**(181,487,311)**	**(1,685,044)**	**(183,172,355)**	**(1,687,893)**	**(184,860,247)**	**(1,769,563)**

Duke Energy Kentucky
ADIT Balance Jan 2018 - March 2021

Code	Name	Dec 2020 Ending Balance	Jan 2021 Current Activity	Jan 2021 Ending Balance	Feb 2021 Current Activity	Feb 2021 Ending Balance	Mar 2021 Current Activity	Mar 2021 Ending Balance
190001/2	ADIT: Prepaid: Taxes							
AT_OTH_190_NC_EPRI_Credit	Other Noncurrent After-tax DTA for EPRI Credit	246,718		246,718		246,718		246,718
AT_OTH_190_NC_R&D_CREDIT	Other Noncurrent After-Tax DTA for R&D Credit	908,590	2,008	910,598	2,008	912,606	2,008	914,614
AT_OTH_190_NC_Solar_ITC	Other Noncurrent After-tax DTA for Solar ITC	3,017,307		3,017,307		3,017,307		3,017,307
F_ITC_190002-411055	ITC Amortization - Non Utility	-		-		-		-
T11A02	Bad Debts - Tax over Book	70,057	-	70,057	-	70,057	-	70,057
T11B08	Surplus Materials Write-Off Asset	7,477	-	7,477	-	7,477	-	7,477
T11B16	OFFSITE GAS STORAGE COSTS	-	-	-	-	-	-	-
T13B19	Leased Meters - Elec & Gas	(13,993)	-	(13,993)	-	(13,993)	-	(13,993)
T15A22	Mark to Market - LT	1,838	-	1,838	-	1,838	-	1,838
T15A95	Unamortized Debt Premium	(7,749)	-	(7,749)	-	(7,749)	-	(7,749)
T15B07	Cash Flow Hedge - Reg Asset/Liab	61,022	-	61,022	-	61,022	-	61,022
T17A02	Accrued Vacation	445,950	-	445,950	-	445,950	-	445,950
T17A40	SEVERANCE RESERVE - LT	22,943	-	22,943	-	22,943	-	22,943
T17A54	MGP Sites	-	-	-	-	-	-	-
T18A02	Deferred Revenue	131,851	-	131,851	-	131,851	-	131,851
T19A22	Miscellaneous NC Taxable Income Adj - DTA	1,304,620	-	1,304,620	-	1,304,620	-	1,304,620
T19A89	GAS SUPPLIER REFUNDS	-	-	-	-	-	-	-
T19A94	UNBILLED REVENUE - FUEL	-	-	-	-	-	-	-
T20A41	Rate Refunds	(121,934)	-	(121,934)	-	(121,934)	-	(121,934)
T20A54	Reg Liability - Rate Case Expense - Amortization - NC	(21,807)	-	(21,807)	-	(21,807)	-	(21,807)
T20C02	Demand Side Management (DSM) Defer	(201,950)	-	(201,950)	-	(201,950)	-	(201,950)
T22A01	Emission Allowance Expense	(5,646)	-	(5,646)	-	(5,646)	-	(5,646)
T22A06	Operating Lease Obligation	2,315,338	-	2,315,338	-	2,315,338	-	2,315,338
T22A07	Charitable Contribution Carryover	4,205	-	4,205	-	4,205	-	4,205
T22A13	Lease Interest Expense	8,398	-	8,398	-	8,398	-	8,398
T22A28	Retirement Plan Expense - Underfunded	4,546,393	(1,272)	4,545,121	(1,272)	4,543,849	(1,272)	4,542,577
T22A29	Non-qualified Pension - Accrual	22,298	-	22,298	-	22,298	-	22,298
T22A56	Environmental Reserve	(17,098)	-	(17,098)	-	(17,098)	-	(17,098)
T22A71	DO NOT USE - Joint Owner Pension Receivable-NC	0	-	0	-	0	-	0
T22B13	ANNUAL INCENTIVE PLAN COMP	57,694	-	57,694	-	57,694	-	57,694
T22B15	PAYABLE 401 (K) MATCH	5,141	-	5,141	-	5,141	-	5,141
T22E02	OPEB Expense Accrual	783,357	-	783,357	-	783,357	-	783,357
T22E06	FAS 112 Medical Expenses Accrual	220,889	-	220,889	-	220,889	-	220,889
Total 190001/2		13,791,912	736	13,792,647	736	13,793,383	736	13,794,119
190155	Deferred Tax - NOL							
AT_OTH_190_NC_Federal NOL	190155_Other NC Federal NOLs	6,369,016		6,369,016		6,369,016		6,369,016
Total 190155		6,369,016	-	6,369,016	-	6,369,016	-	6,369,016
190156	Deferred Tax_State NOLs							
AT_OTH_190_KY_STATE_NOL	Other KY State NOLs	34,725		34,725		34,725		34,725
Total 190156		34,725	-	34,725	-	34,725	-	34,725
Account 190		20,195,653	736	20,196,389	736	20,197,124	736	20,197,860
282100/1	ADIT: PP&E							
AT_OTH_282_NC	Other Non-Current After-Tax DTL for PP&E	2,861,323		2,861,323		2,861,323		2,861,323
AT_OTH_282_NC_Solar	Other Noncurrent After-tax DTA for Solar Basis Reductio	(316,817)		(316,817)		(316,817)		(316,817)
AT_OTH_282_NC_ST	Other Non-Current AT ST DTL for PP&E	5,818,993		5,818,993		5,818,993		5,818,993
AT_OTH_282_NC_ST_TBBS	Other Non-Current AT ST DTL for TBBS	512,932		512,932		512,932		512,932
AT_OTH_282_NC_TBBS	Other Non-Current After-Tax DTL for TBBS	(3,907,073)		(3,907,073)		(3,907,073)		(3,907,073)
F_ARAM_190053-411100	FERC - FIT Plant Adj (Util - 411)	283,207		283,207		283,207		283,207
F_ARAM_190054-411102	FERC - SIT Plant Adj (Util 411)	110,615		110,615		110,615		110,615
F_ARAM_282100-410100	FERC - FIT Plant Adj (Util - 410)	(38,900)		(38,900)		(38,900)		(38,900)
F_ARAM_282100-411100	FERC - FIT Plant Adj (Util - 411)	872,016	1,328	873,344	1,328	874,672	1,328	876,000
F_ARAM_282101-410102	FERC - SIT Plant Adj (Util - 410)	84,651		84,651		84,651		84,651
F_ARAM_282101-411101	FERC - SIT Plant Adj (Util - 411)	1,432,121		1,432,121		1,432,121		1,432,121
T13A04	AFUDC Interest	(316,824)	-	(316,824)	-	(316,824)	-	(316,824)
T13A05	Repairs Allowed on Post ADR Prop	80,320	-	80,320	-	80,320	-	80,320
T13A08	Book Depreciation/Amortization	93,924,299	982,076	94,906,375	981,876	95,888,251	982,294	96,870,545
T13A09	Book Capital Lease Meters	(1,549,912)	-	(1,549,912)	-	(1,549,912)	-	(1,549,912)
T13A10	Adjustment to Book Depreciation	1,677,791	-	1,677,791	-	1,677,791	-	1,677,791
T13A11	Lease Right of Use Asset	(2,303,399)	-	(2,303,399)	-	(2,303,399)	-	(2,303,399)
T13A12	Book Gain/Loss on Property	(848,043)	-	(848,043)	-	(848,043)	-	(848,043)

T13A14	Contributions in Aid (CIAC's)	1,333,247	-	1,333,247	-	1,333,247	-	1,333,247
T13A16	Cost of Removal	(3,113,275)	-	(3,113,275)	-	(3,113,275)	-	(3,113,275)
T13A18	Capitalized Hardware/Software	41,892	-	41,892	-	41,892	-	41,892
T13A19	After Tax ADC,M&E, ITC Temporary	(1,043,843)	(8,749)	(1,052,592)	(8,749)	(1,061,342)	(8,749)	(1,070,091)
T13A26	Tax Interest Capitalized	3,409,281	28,997	3,438,278	32,555	3,470,833	36,696	3,507,530
T13A28	Tax Depreciation/Amortization	(159,971,190)	(984,824)	(160,956,014)	(984,824)	(161,940,839)	(984,824)	(162,925,663)
T13A30	Tax Gains/Losses	(21,911,798)	(123,640)	(22,035,437)	(123,640)	(22,159,077)	(123,640)	(22,282,716)
T13A69	Casualty Loss	381,694	-	381,694	-	381,694	-	381,694
T13A75	Section 174 R&E Deduction	(1,542,204)	-	(1,542,204)	-	(1,542,204)	-	(1,542,204)
T13A77	Repairs 481(a) (Pursuant to 3115)	(13,630,762)	-	(13,630,762)	-	(13,630,762)	-	(13,630,762)
T13A99	FAS 34 Book Capitalized Interest	-	-	-	-	-	-	-
T13B09	Book Depreciation Charged to Other Accounts	75,438	-	75,438	-	75,438	-	75,438
T13B11	Excess Salvage	7,591	-	7,591	-	7,591	-	7,591
T13B18	Loss on ACRS	1,601,781	-	1,601,781	-	1,601,781	-	1,601,781
T13B20	Meters & Transformers	(128,196)	-	(128,196)	-	(128,196)	-	(128,196)
T13B23	Non-Cash Overhead Basis Adj	2,149,239	-	2,149,239	-	2,149,239	-	2,149,239
T13B26	Equipment Repairs - Annual Adj	(86,216,695)	(1,557,820)	(87,774,515)	(1,557,820)	(89,332,334)	(1,557,820)	(90,890,154)
T13B27	481(a) Fixed Asset Retirement	350,443	-	350,443	-	350,443	-	350,443
T13B31	Impairment of Plant Assets	289,131	-	289,131	-	289,131	-	289,131
T13B32	T & D Repairs 481(a) (pursuant to 3115)	(5,435,744)	-	(5,435,744)	-	(5,435,744)	-	(5,435,744)
T13B33	T & D Repairs - Annual Adj.	(9,763,957)	(154,910)	(9,918,866)	(154,910)	(10,073,776)	(154,910)	(10,228,685)
T13B43	Section 481(a) Casualty Losses	1,145,082	-	1,145,082	-	1,145,082	-	1,145,082
T13B44	Capitalized OH - Transportation	1,613	-	1,613	-	1,613	-	1,613
T22A16	Self Developed Software	(798,846)	-	(798,846)	-	(798,846)	-	(798,846)
TKY010	KY - Bonus Depreciation Adj	5,053,712	-	5,053,712	-	5,053,712	-	5,053,712
Total 282100/1		(189,339,063)	(1,817,542)	(191,156,604)	(1,814,183)	(192,970,788)	(1,809,625)	(194,780,413)
283100/1	ADIT: Other							
T15A24	Loss on Reacquired Debt-Amort	(139,164)	1,784	(137,380)	1,784	(135,596)	1,784	(133,812)
T15B02	Reg Asset/Liab Def Revenue	(333,341)	-	(333,341)	-	(333,341)	-	(333,341)
T15B04	Reg Asset - Accr Pension FAS158 - FAS87Qual	1	-	1	-	1	-	1
T15B17	Reg Liab RSLI & Other Misc Dfd Costs	59,994	-	59,994	-	59,994	-	59,994
T15B18	Reg Asset Storm Damage Recovery	(632,654)	-	(632,654)	-	(632,654)	-	(632,654)
T15B28	Reg Asset - Rate Case Expense	(71,943)	-	(71,943)	-	(71,943)	-	(71,943)
T15B29	Reg Asset-Pension Post Retirement PAA-FAS87Qual an	(6,937,333)	-	(6,937,333)	-	(6,937,333)	-	(6,937,333)
T15B35	Regulatory Asset - Carbon Management	(378,023)	-	(378,023)	-	(378,023)	-	(378,023)
T15B37	Reg Asset-Pension Post Retirement PAA-FAS87NQ and	(11,160)	-	(11,160)	-	(11,160)	-	(11,160)
T15B38	Reg Asset-Pension Post Retirement PAA-FAS 106 and (	(337,527)	-	(337,527)	-	(337,527)	-	(337,527)
T15B40	Reg Asset - Accr Pension FAS158 - FAS87NQ	903,928	-	903,928	-	903,928	-	903,928
T15B41	Reg Asset - Accr Pension FAS158 - FAS 106/112	2,850	-	2,850	-	2,850	-	2,850
T15B43	Reg Asset - Transition from MISO to PJM	3,677,275	-	3,677,275	-	3,677,275	-	3,677,275
T15B45	Reg Asset - Plant Related Retirements	(0)	-	(0)	-	(0)	-	(0)
T15B69	Reg Asset Opt Out Tariff IT Modifications	(20,244)	-	(20,244)	-	(20,244)	-	(20,244)
T15B77	Non-AMI Meters Retired Early - NBV	(1,086,157)	-	(1,086,157)	-	(1,086,157)	-	(1,086,157)
T15B81	Reg Asset_Liab - Outage Costs	(600,343)	-	(600,343)	-	(600,343)	-	(600,343)
T17A01	Vacation Carryover - Reg Asset	(255,292)	-	(255,292)	-	(255,292)	-	(255,292)
T20A38	Regulatory Asset - Deferred Plant Costs	(8,972,689)	93,261	(8,879,427)	93,261	(8,786,166)	93,261	(8,692,904)
T20A40	Non-Current Portion of Reg Asset	-	-	-	-	-	-	-
T22A15	Operating Lease Deferral	-	-	-	-	-	-	-
T22A23	Retirement Plan Expense - Overfunded	(1,745,834)	-	(1,745,834)	-	(1,745,834)	-	(1,745,834)
T22B16	Miscellaneous NC Taxable Income Adj - DTL	(608,743)	-	(608,743)	-	(608,743)	-	(608,743)
Total 283100/1		(17,486,400)	95,045	(17,391,355)	95,045	(17,296,309)	95,045	(17,201,264)
Total Deferred Income Taxes		**(186,629,810)**	**(1,721,760)**	**(188,351,571)**	**(1,718,402)**	**(190,069,973)**	**(1,713,844)**	**(191,783,816)**

EXHIBIT ____ (LK-3)

REQUEST:

Refer to the application, Volume 11, Section B, Schedule B-6, page 2 of 2, and line 6, columns 3, 4, and 5 and line 9, column 4.

a. Explain why the accumulated deferred income taxes (ADIT) generated by the Investment Tax Credits are adjusted to zero for ratemaking purposes.

b. Provide the calculation of the ($2,527,989) adjustment to eliminate ADIT for items not included in rate base.

RESPONSE:

a. Duke Energy Kentucky is not permitted to reduce rate base by any portion of its ITC credit because of the election it made to apply the ratable flow-through method under Former Internal Revenue Code section 46(f)(2), which remains applicable under IRC section 50(d)(2) (Note that all subsequent statutory references in this response to "sections" are to the Internal Revenue Code). The tax normalization rules for ITC allowed taxpayers to adopt one of two methods for how ITC benefits are flowed through to ratepayers over a period of time. Under Former section 46(f)(1), taxpayers were generally permitted to reduce rate base by the amount of the tax benefit obtained by the credit, provided that the rate base reduction is restored, i.e., the reduction is reversed, no slower than over the useful life of the property. Taxpayers that utilize the rate base reduction approach are not permitted to reduce the cost of service by any amount of the credit. In contrast, Former § 46(f)(2) provides an election under which a taxpayer is permitted to take into account a ratable portion of the ITC for purposes of determining cost of service, but a taxpayer that makes this election is not permitted to reduce rate base by any portion of the credit. Treasury regulations provide that section 46(f)(1) applies to all of a taxpayer's section 46(f) property in the absence of an election under section 46(f)(2). In contrast, if an election is made under section 46(f)(2), then section 46(f)(1) does not apply to any of the taxpayer's section 46(f) property. Treas. Reg. section 1.46-6(h)(ii). Once a taxpayer has adopted one method or approach, that method applies to all the taxpayer's section 46(f) property and they are not able to adopt the other alternative approach for any other property eligible for section 46. Duke Energy Kentucky made an election to apply section 46(f)(2) in the 1970s. As a result, since making that election, Duke Energy Kentucky has applied the ratable flow-through method to all of its section 46(f) property. In short, while some taxpayers are permitted to reduce rate base by the amount of the credit under Former IRC section 46(f)(1), that rate base reduction method is not available to Duke Energy Kentucky and other regulated taxpayers who have elected to apply the ratable flow-through method under Former IRC section 46(f)(2). Instead, Duke Energy Kentucky must flow ITC credits back to ratepayers through its cost of service no quicker than ratably over the useful life of the asset to which the credit relates.

b. See STAFF-DR-02-009(b) Attachment for the details supporting the adjustment to eliminate ADIT for items not included in rate base. The adjustment has the effect of increasing the ADITs included in rate base and therefore decreasing rate base because the adjustment is removing a net deferred tax asset. The Company has excluded all deferred tax assets and deferred tax liabilities that do not relate to assets in rate base.

PERSON RESPONSIBLE: John R. Panizza – a.
Sarah E. Lawler – b.

LINE NO.	ACCOUNT NUMBER	DESCRIPTION	ADJUSTMENT
	190		
1		Other Noncurrent After-tax DTA for EPRI Credit	216,346
2		Other Noncurrent After-Tax DTA for R&D Credit	922,184
3		Bad Debts - Tax over Book	70,274
4		Mark to Market - LT	1,838
5		Accrued Vacation	450,495
6		SEVERANCE RESERVE - LT	25,513
7		Deferred Revenue	104,406
8		Miscellaneous NC Taxable Income Adj - DTA	476,297
9		Rate Refunds	(121,934)
10		Demand Side Management (DSM) Defer	632,806
11		Emission Allowance Expense	(6,082)
12		Operating Lease Obligation	2,341,678
13		Charitable Contribution Carryover	30,521
14		Lease Interest Expense	8,487
15		Retirement Plan Expense - Underfunded	2,841,332
16		Non-qualified Pension - Accrual	22,735
17		Environmental Reserve	(17,098)
18		ANNUAL INCENTIVE PLAN COMP	17,620
19		PAYABLE 401 (K) MATCH	2,840
20		OPEB Expense Accrual	767,856
21		FAS 112 Medical Expenses Accrual	248,832
22			
23	Account 190 Total		9,036,946
24			
25			
26		Reg Asset/Liab Def Revenue	(790,560)
27		Reg Asset - Accr Pension FAS158 - FAS87Qual	1
28		Reg Liab RSLI & Other Misc Dfd Costs	143,923
29		Reg Asset Storm Damage Recovery	(714,287)
30		Reg Asset-Pension Post Retirement PAA-FAS87Qual .	(5,602,082)
31		Regulatory Asset - Carbon Management	(290,790)
32		Reg Asset-Pension Post Retirement PAA-FAS87NQ ar	(11,415)
33		Reg Asset-Pension Post Retirement PAA-FAS 106 anc	(356,782)
34		Reg Asset - Accr Pension FAS158 - FAS87NQ	922,302
35		Reg Asset - Accr Pension FAS158 - FAS 106/112	2,850
36		Reg Asset - Transition from MISO to PJM	3,666,482
37		Reg Asset Opt Out Tariff IT Modifications	(22,856)
38		Non-AMI Meters Retired Early - NBV	(1,308,623)
39		Reg Asset_Liab - Outage Costs	(600,343)
40		Vacation Carryover - Reg Asset	(255,292)
41		Operating Lease Deferral	(9,250)
42		Retirement Plan Expense - Overfunded	(1,282,235)
43			
44	Account 283 Total		(6,508,957)
45			
46	190, 283	Total Deferred Income Taxes Adjustment	2,527,989

EXHIBIT ____ (LK-4)

AG-DR-02-005

REQUEST:

Refer to the response to AG-DR-01-014(b)_Attachment, which provides the per books monthly ADIT in the test year by temporary difference. Refer to the response to Staff-DR-02-009(b), which provides the ADIT by temporary difference that the Company removed from the rate base calculation.

a. Explain why the Company did not remove the Other Noncurrent After-Tax DTA for Solar ITC from the rate base calculation.

b. Explain why the DTA for Solar ITC should be included, while the DTAs for EPRI Credit and R&D Credit are excluded. Provide a copy of all authorities relied on for your response.

RESPONSE:

a. The Other Noncurrent After-Tax DTA for Solar ITC should have been excluded in the same way as the DTA's for the EPRI and R&D Credits.

b. See part (a) above.

PERSON RESPONSIBLE: Sarah E. Lawler

EXHIBIT ____ (LK-5)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's Second Set Data Requests
Date Received: November 12, 2019

AG-DR-02-021

REQUEST:

Provide the accounts payable balances for fuel inventories (Electric Division) at month-end for each month January 2018 through December 2018 (actuals), January 2019 through December 2019 (actuals for months where actual information is available and forecasts for remaining months), and for each month in the forecast test year. Describe the process the Company utilized to determine the accounts payable balances for fuel inventories. If these payables are maintained in a separate subaccount, then provide the balances for the months requested by subaccount.

RESPONSE:

See AG-DR-02-021 Attachment. The Company maintains separate accounts payable accounts for fuel inventories. Forecasted test year accounts payable balances related to fuel are below:

Apr-20	$2,647,323
May-20	1,878,066
Jun-20	2,501,935
Jul-20	3,626,264
Aug-20	3,094,662
Sep-20	1,964,682
Oct-20	909,376
Nov-20	674,673
Dec-20	1,864,217

Jan-21	3,709,261
Feb-21	2,724,879
Mar-21	1,505,014

PERSON RESPONSIBLE: Danielle L. Weatherston
Christopher M. Jacobi

Business Unit Hierarchy FE_DE_KY - DE Kentucky Electric

TTD Actual Amount

Fiscal Year	Calendar Quarter	Accounting Period	0232163 - Emission Allowance A/P	0232170 - Accounts Payable-Coal	0232175 - LIMESTONE & FREIGHT PAYABLE	0232176 - Reagent Payable	0232180 - Accounts Payable-Oil Stocks	Grand Total
2018	Q1 2018	Jan 2018	1,000.00	(2,871,133.77)	(577,745.16)	(64,527.51)	0.00	(3,512,406.44)
		Feb 2018	1,000.00	(1,111,871.03)	(217,859.53)	(40,580.72)	0.00	(1,369,311.28)
		Mar 2018	1,000.00	(1,109,323.77)	0.00	0.00	0.00	(1,108,323.77)
	Q2 2018	Apr 2018	1,000.00	732,623.97	0.00	0.00	0.00	733,623.97
		May 2018	1,000.00	(1,615,034.33)	0.00	0.00	(309,707.02)	(1,923,741.35)
		Jun 2018	1,000.00	(1,003,102.90)	(229,845.29)	(31,975.75)	(88,154.58)	(1,352,078.52)
	Q3 2018	Jul 2018	1,000.00	(3,305,325.43)	(999,329.81)	(46,652.74)	0.00	(4,350,307.98)
		Aug 2018	1,000.00	(4,503,679.75)	(732,137.69)	(55,628.45)	(141,379.04)	(5,431,824.93)
		Sep 2018	1,000.00	(1,900,005.17)	(574,699.55)	(37,477.60)	0.00	(2,511,182.32)
	Q4 2018	Oct 2018	1,000.00	(2,990,483.82)	(419,556.71)	(62,777.84)	0.00	(3,471,818.37)
		Nov 2018	0.00	(3,251,330.00)	(255,347.99)	(55,169.05)	(170,707.67)	(3,732,554.71)
		Dec 2018	0.00	(2,394,411.08)	(771,243.30)	(80,138.99)	0.00	(3,245,793.37)
2019	Q1 2019	Jan 2019	0.00	(3,734,882.73)	(490,562.93)	(83,244.74)	0.00	(4,308,690.40)
		Feb 2019	0.00	(3,358,397.70)	(462,097.50)	(54,756.80)	(135,316.69)	(4,010,568.69)
		Mar 2019	0.00	(5,905,440.83)	(688,044.51)	(55,100.91)	(49,192.03)	(6,697,778.28)
	Q2 2019	Apr 2019	0.00	(19,983.89)	(165,794.76)	0.01	0.00	(185,778.64)
		May 2019	0.00	(4,249,710.54)	(478,646.26)	(45,220.21)	(31,935.05)	(4,805,512.06)
		Jun 2019	0.00	(4,000,060.35)	(646,054.34)	(42,407.61)	0.00	(4,688,522.30)
	Q3 2019	Jul 2019	0.00	(2,684,200.92)	(353,444.05)	(46,595.96)	0.00	(3,084,240.93)
		Aug 2019	0.00	(1,767,653.77)	(686,884.13)	(51,218.53)	(58,130.86)	(2,563,887.29)
		Sep 2019	0.00	(1,650,602.92)	(507,557.52)	(34,687.17)	(436,924.52)	(2,629,772.13)
	Q4 2019		0.00	4,193.52	0.00	0.01	367,672.64	371,866.17

EXHIBIT ____ (LK-6)

AG-DR-02-022

REQUEST:

Provide the accounts payable balances for M&S inventories (Electric Division), including limestone inventories and stores expense balances as included in WPB-5.1c, at month-end for each month January 2018 through December 2018 (actuals), January 2019 through December 2019 (actuals for months where actual information is available and forecasts for remaining months), and for each month in the forecast test year. Describe the process the Company utilized to determine the accounts payable balances for M&S inventories. If these payables are maintained in a separate subaccount, then provide the balances for the months requested by subaccount. Provide all support developed and relied on for this response, including all calculations, if any.

RESPONSE:

The accounts payable balance associated with limestone inventories is included in AG-DR-02-021. The accounts payable balances for other M&S accounts and stores expense are accumulated in a vouchers payable account along with multitudes of varying items. As such, a breakout of that information does not exist.

PERSON RESPONSIBLE: Danielle Weatherston

EXHIBIT ____ (LK-7)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's Second Set Data Requests
Date Received: November 12, 2019

AG-DR-02-029

REQUEST:

Provide the PUCO docket number for Duke Energy Ohio's most recent base rate case proceeding. Describe the DEO request for cash working capital in that proceeding and provide the relevant schedules and calculations.

RESPONSE:

a. Case No. 17-32-EL-AIR, *et al.*

b. Duke Energy Ohio requested $0 for cash working capital in that case. Although the Public Utilities Commission of Ohio (PUCO) has, in some instances (*e.g.*, Ohio Gas Company in Case No. 17-1139-GA-AIR, *et al.*, approved on February 21, 2018), allowed utilities to estimate cash working capital using the 1/8th O&M method, it has rejected Duke Energy Ohio's attempts to use that methodology in past cases; therefore, the Company abided by the PUCO's decisions in prior rate cases involving Duke Energy Ohio.

PERSON RESPONSIBLE: William Don Wathen Jr.

EXHIBIT ____ (LK-8)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's Second Set Data Requests
Date Received: November 12, 2019

AG-DR-02-030

REQUEST:

Confirm that in its filing in the pending IURC Case No. 45253, Duke Energy Indiana included $0 for cash working capital in rate base. Provide all reasons why the Kentucky Public Service Commission should include cash working capital based on the one-eighth approach in this proceeding when Duke Energy Indiana included $0 for cash working capital in rate base in the Indiana proceeding.

RESPONSE:

a. Duke Energy Indiana sought $0 for cash working capital in its pending rate case.

b. Different regulators have different regulatory models. The Kentucky Public Service Commission has historically adopted the 1/8th O&M method for calculating cash working capital and it is considered to be a standard methodology for estimating this rate base component. Prior witnesses for the Attorney General has recognized this as the Kentucky Commission's practice. One such witness for the Attorney General was Robert J. Henkes who testified in Case No. 2009-00202 that "it is [his] understanding that the Commission has *consistently allowed* [Duke Energy Kentucky's] cash working capital to be determined based on this modified 1/8th O&M method." (emphasis added)

Duke Energy Kentucky followed this longstanding precedent in developing its estimate of cash working capital as it has done in every rate case for electric and gas service over many years.

PERSON RESPONSIBLE: William Don Wathen Jr.

EXHIBIT ____ (LK-9)

AG-DR-01-042

REQUEST:

Provide a schedule of FTEs and payroll dollars separated between expense, capital, and other, for DEK by department and by month for 2016, 2017, 2018, budgeted in each month 2019, actual in each month 2019 for which actual information is available, and budgeted in each month 2020.

RESPONSE:

Payroll Dollars: See attachment AG-DR-01-042 Attachment 1 for amounts separated between expense, capital, and other, for DEK by department and by month for each of the periods requested.

Actual Headcounts: See attachment AG-DR-01-042 Attachment 2 for actual headcounts by month by department for 2016 – September 2019.

Budgeted Headcounts: The Company does not budget headcount.

PERSON RESPONSIBLE: Renee H. Metzler

Duke Energy Kentucky - Electric Operations
AG-DR-01-042

Request:

42. Provide a schedule of FTEs and payroll dollars separated between expense, capital, and other, for DEK by department and by month for 2016, 2017, 2018, budgeted in each month 2019, actual in each month 2019 for which actual information is available, and budgeted in each month 2020.

Response:

See the below table for payroll labor cost for Duke Energy Kentucky (Electric). Amounts extracted from the company's general ledger system (budget) for the test period.

	Payroll Labor Costs (Budgeted 2020) - F			
	Expense	Capital	Other deferred	Total
January	$ 2,441,897	$ 1,326,569	$ 122,271	$ 3,890,737
February	2,083,133	1,286,824	120,883	3,490,840
March	2,265,241	1,437,397	143,914	3,846,553
April	2,230,465	1,368,120	125,246	3,723,831
May	2,159,058	1,362,094	125,451	3,646,603
June	2,229,466	1,470,382	125,501	3,825,348
July	2,421,244	1,573,654	123,795	4,118,693
August	2,257,432	1,751,188	143,832	4,152,452
September	2,156,367	1,645,785	123,811	3,925,963
October	2,138,807	1,604,589	123,842	3,867,238
November	2,142,835	1,565,437	123,846	3,832,119
December	2,437,553	1,506,139	123,984	4,067,676
Total	**$ 26,963,500**	**$ 17,898,178**	**$ 1,526,376**	**$ 46,388,053**

Duke Energy Kentucky - Electric Operations
AG-DR-01-042

	Payroll Labor Costs (Budgeted 2019) - E			
	Expense	Capital	Other deferred	Total
January	$ 1,885,133	$ 1,102,175	$ 128,668	$ 3,115,976
February	1,871,303	1,093,005	128,341	3,092,649
March	2,320,226	1,210,419	152,330	3,682,975
April	2,009,038	1,131,013	132,819	3,272,870
May	1,936,748	1,141,285	133,018	3,211,051
June	1,975,194	1,195,565	133,079	3,303,838
July	1,933,972	1,188,864	131,359	3,254,195
August	2,307,825	1,276,007	152,249	3,736,081
September	1,931,823	1,307,861	131,379	3,371,063
October	1,906,701	1,356,529	131,404	3,394,634
November	1,943,498	1,270,296	131,410	3,345,204
December	1,904,604	1,301,963	131,406	3,337,973
Total	**$ 23,926,064**	**$ 14,574,982**	**$ 1,617,463**	**$ 40,118,509**

	Payroll Labor Costs (Actual through Sept 2019) - D			
	Expense	Capital	Other deferred	Total
January	$ 1,490,595	$ 1,025,326	$ 56,995	$ 2,572,916
February	1,610,085	1,095,923	152,950	2,858,959
March	1,964,086	1,373,186	152,216	3,489,488
April	1,746,677	1,156,403	135,478	3,038,558
May	1,740,380	1,149,248	135,342	3,024,970
June	1,557,405	1,208,230	104,837	2,870,472
July	1,536,486	1,093,614	102,487	2,732,587

Duke Energy Kentucky - Electric Operations
AG-DR-01-042

August		1,968,305		1,466,672		163,219		3,598,196
September		1,556,628		1,099,961		117,329		2,773,918
October								
November								
December								
Total	$	15,170,646	$	10,668,563	$	1,120,853	$	26,960,063

				Payroll Labor Costs (2018) C				
		Expense		Capital		Other deferred		Total
January	$	1,612,380	$	841,231	$	27,510	$	2,481,121
February		1,689,696		998,364		183,628		2,871,688
March		2,358,063		1,400,023		165,704		3,923,790
April		1,829,194		1,331,348		121,706		3,282,247
May		1,861,974		1,225,392		106,753		3,194,119
June		2,010,986		1,204,297		110,821		3,326,105
July		1,540,410		962,657		75,143		2,578,210
August		1,847,692		1,204,090		127,110		3,178,892
September		1,677,054		999,802		99,949		2,776,806
October		1,626,639		970,980		117,196		2,714,816
November		1,733,318		904,661		79,428		2,717,407
December		1,349,336		909,068		123,373		2,381,777
Total	$	21,136,742	$	12,951,914	$	1,338,321	$	35,426,977

		Payroll Labor Costs (2017) B		
	Expense	Capital	Other deferred	Total

Duke Energy Kentucky - Electric Operations
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January	$ 1,625,622	$ 717,905	$ (187,603)	$ 2,155,923
February	1,638,583	808,031	52,796	2,499,409
March	2,280,388	889,767	71,525	3,241,680
April	1,646,169	723,414	58,243	2,427,827
May	1,898,822	761,281	71,356	2,731,459
June	1,613,931	737,873	61,898	2,413,702
July	1,664,341	794,096	51,022	2,509,459
August	1,600,238	954,773	105,097	2,660,108
September	2,104,814	896,528	119,898	3,121,239
October	1,689,730	946,215	121,759	2,757,703
November	1,521,619	971,238	72,809	2,565,665
December	1,298,318	809,905	12,112	2,120,336
Total	**$ 20,582,574**	**$ 10,011,025**	**$ 610,911**	**$ 31,204,510**
				31,204,510

	Payroll Labor Costs (2016) A			
	Expense	**Capital**	**Other deferred**	**Total**
January	$ 1,684,121	$ 487,800	$ 11,588	$ 2,183,509
February	1,758,195	560,983	56,708	2,375,887
March	1,798,544	597,351	46,729	2,442,624
April	2,476,545	815,005	64,163	3,355,712
May	1,778,098	670,640	30,947	2,479,686
June	1,664,130	316,308	25,811	2,006,249
July	1,565,186	591,945	14,335	2,171,466
August	1,637,750	636,507	40,645	2,314,902
September	2,094,999	673,879	29,874	2,798,751
October	1,643,272	742,122	(21,226)	2,364,167
November	1,538,914	363,620	2,260	1,904,795
December	1,460,647	657,047	(115,958)	2,001,736

Duke Energy Kentucky - Electric Operations
AG-DR-01-042

Total	**$ 21,100,401**	**$ 7,113,207**	**$ 185,874**	**$ 28,399,483**
				28,399,483

A See 12ME DEC 2016 tab for department detail, by month.
B See 12ME DEC 2017 tab for department detail, by month.
C See 12ME DEC 2018 tab for department detail, by month.
D See 9ME SEP 2019 tab for department detail, by month.
E See 2019 (Budget) tab for department detail, by month.
F See 2020 (Budget) tab for department detail, by month.

EXHIBIT ____ (LK-10)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's Second Set Data Requests
Date Received: November 12, 2019

AG-DR-02-039

REQUEST:

Refer to the response to AG-DR-01-042 Attachment 1, pages 1-5, and Attachment 2 related to actual FTEs and actual and projected payroll dollars for DEK (Electric) separated between expense, capital, and other. The average monthly payroll expense budgeted for 2020 equals $2.247 million. The average monthly payroll expense budgeted for 2019 equals $1.994 million. The average monthly payroll expense actually recorded during the first 9 months in 2019 was only $1.686 million. Finally, the DEK (Electric) headcount decreased from 147 FTEs at December 2018 to 134 in January 2019 and again to 175 during the months of July 2019 through September 2019, primarily in the category of "Distb, Cust Ops & DE Carolina."

a. Explain all reasons why monthly payroll expense would increase from the actual $1.686 million in 2019 to the budgeted $2.247 million in 2020, an average increase of $0.561 million per month or an increase of over 33%.

b. Explain all reasons why monthly payroll expense would increase from the budgeted $1.994 million in 2019 to the budgeted $2.247 million in 2020, an average increase of $0.253 million per month or an increase of almost 13%.

c. Explain all reasons why the headcount decreased from 195 FTEs at December 2018 to 181 in January 2019 and again to 175 during the months of April 2019 through September 2019, primarily in the category of "Distb, Cust Ops & DE Carolina."

d. Describe in detail all expectations related to the number of DEK (Electric) headcount FTEs for the remainder of 2019, for 2020, and for the first three months of 2021 compared to the September 2019 level of 127 FTEs. Be sure to distinguish between such things as new employees for new programs, filling vacancies, employee reductions by reason, and other.

RESPONSE:

a. Please see AG-DR-02-039 Attachment for a revised AG-DR-01-042 Attachment 1. After correcting the actuals dataset for inadvertently excluded accounts and resource types, the average actual monthly payroll expense that is comparable to the 2020 budget is $2.058 million. With this adjustment, payroll expenses are reflecting an increase of 9% between actual periods and the 2020 budget. The 9% increase in payroll costs is due to merit/promotion increases and additional increases in Customer Services and Delivery.

b. Please see AG-DR-02-039 Attachment for a revised AG-DR-01-042 Attachment 1. After correcting the 2019 budget dataset for inadvertently excluded accounts, the average 2019 budgeted payroll expense that is comparable to the 2020 budget is $2.111 million. With this adjustment, payroll expenses are reflecting an increase of 6% between the 2019 and 2020 budget. The 6% increase in payroll costs is due to merit/promotion increases and additional increases in Customer Services.

c. <u>Decrease in employee counts in "Distb, Cust Ops & DE Carolinas" from Dec 2018 to Jan 2019:</u> 2 employees terminated and 12 employees transferred to another payroll company.

Decrease in "Distb, Cust Ops & DE Carolinas" from Jan 2019 to July 2019: Counts for terminations and employee transfers to other payroll companies higher than counts for new hires and employee transfers into Duke Energy Kentucky from other payroll companies.

d. Our current company guidance is to maintain a flat headcount; therefore, headcount is expected to remain relatively flat considering new positions, employee transfers, reorganizations, and normal attrition. Duke Energy Kentucky has one open position and we would expect to add this position to headcounts in the next 1-3 months. Positions that will be posted in the future are unknown as we do not know which positions will be affected by attrition.

PERSON RESPONSIBLE: Christopher M. Jacobi – a., b.
Renee H. Metzler – c., d.

Duke Energy Kentucky - Electric Operations
AG-DR-02-039

Response:
Below is a revision to attachment AG-DR-01-042 Attachment 1 to include the following:
Accounts: 0506000, 0557000, and 0588100 in 2019 budget and all actuals periods
Resource type: Unproductive labor (holidays, vacation, sick time) for all actuals periods

	Payroll Labor Costs (Budgeted 2020) - F			
	Expense	Capital	Other deferred	Total
January	$ 2,441,897	$ 1,326,569	$ 122,271	$ 3,890,737
February	2,083,133	1,286,824	120,883	3,490,840
March	2,265,241	1,437,397	143,914	3,846,553
April	2,230,465	1,368,120	125,246	3,723,831
May	2,159,058	1,362,094	125,451	3,646,603
June	2,229,466	1,470,382	125,501	3,825,348
July	2,421,244	1,573,654	123,795	4,118,693
August	2,257,432	1,751,188	143,832	4,152,452
September	2,156,367	1,645,785	123,811	3,925,963
October	2,138,807	1,604,589	123,842	3,867,238
November	2,142,835	1,565,437	123,846	3,832,119
December	2,437,553	1,506,139	123,984	4,067,676
Total	**$ 26,963,500**	**$ 17,898,178**	**$ 1,526,376**	**$ 46,388,053**

Duke Energy Kentucky - Electric Operations
AG-DR-02-039

	Payroll Labor Costs (Budgeted 2019) - E			
	Expense	Capital	Other deferred	Total
January	$ 2,017,857	$ 1,098,295	$ 128,668	$ 3,244,820
February	1,988,163	1,089,125	128,341	3,205,629
March	2,452,606	1,206,403	152,329	3,811,339
April	2,127,474	1,127,001	132,819	3,387,295
May	2,050,818	1,137,273	133,018	3,321,108
June	2,095,330	1,191,553	133,079	3,419,961
July	2,035,234	1,184,852	131,359	3,351,446
August	2,436,497	1,271,995	152,249	3,860,741
September	2,039,630	1,303,849	131,378	3,474,857
October	2,002,300	1,352,517	131,404	3,486,221
November	2,058,444	1,266,284	131,410	3,456,137
December	2,027,699	1,297,951	131,406	3,457,056
Total	$ 25,332,051	$ 14,527,098	$ 1,617,461	$ 41,476,610

	Payroll Labor Costs (Actual through Sept 2019) - D			
	Expense	Capital	Other deferred	Total
January	$ 1,963,218	$ 1,153,411	$ 169,674	$ 3,286,303
February	1,905,595	1,215,498	164,246	3,285,339
March	2,334,464	1,544,898	192,469	4,071,832
April	2,061,706	1,287,162	188,107	3,536,975
May	1,966,924	1,288,399	181,461	3,436,784
June	1,982,770	1,342,485	202,437	3,527,693
July	2,011,547	1,261,985	188,154	3,461,687
August	2,363,470	1,683,593	201,898	4,248,961
September	1,934,729	1,254,301	185,945	3,374,976
October				
November				
December				
Total	$ 18,524,424	$ 12,031,733	$ 1,674,391	$ 32,230,549

Duke Energy Kentucky - Electric Operations
AG-DR-02-039

	Payroll Labor Costs (2018) C			
	Expense	Capital	Other deferred	Total
January	$ 2,137,169	$ 950,432	$ 114,858	$ 3,202,459
February	1,918,908	1,107,593	189,333	3,215,834
March	2,618,225	1,550,919	212,670	4,381,813
April	2,057,292	1,404,795	155,981	3,618,068
May	2,126,995	1,296,733	159,276	3,583,003
June	2,300,674	1,286,473	170,781	3,757,927
July	2,046,083	1,104,292	159,541	3,309,916
August	2,209,255	1,370,625	177,667	3,757,547
September	2,025,094	1,104,712	163,271	3,293,077
October	1,951,272	1,092,303	160,736	3,204,311
November	2,153,582	1,038,101	162,885	3,354,568
December	1,914,897	1,069,010	253,812	3,237,720
Total	$ 25,459,445	$ 14,375,987	$ 2,080,809	$ 41,916,242

	Payroll Labor Costs (2017) B			
	Expense	Capital	Other deferred	Total
January	$ 2,278,262	$ 791,918	$ (95,786)	$ 2,974,394
February	1,938,046	890,651	73,452	2,902,149
March	2,591,049	984,733	101,235	3,677,016
April	2,070,105	815,936	108,369	2,994,410
May	2,189,034	851,935	117,021	3,157,990
June	2,000,629	823,978	114,773	2,939,380
July	2,130,598	897,280	132,112	3,159,991
August	1,935,022	1,050,248	136,897	3,122,168
September	2,511,104	1,031,050	164,266	3,706,421
October	1,971,670	1,075,922	157,414	3,205,006
November	1,876,320	1,121,383	151,441	3,149,144
December	1,886,247	988,516	151,253	3,026,015
Total	$ 25,378,086	$ 11,323,552	$ 1,312,446	$ 38,014,084

Duke Energy Kentucky - Electric Operations
AG-DR-02-039

	Payroll Labor Costs (2016) A			
	Expense	Capital	Other deferred	Total
January	$ 2,343,374	$ 548,386	$ 86,540	$ 2,978,300
February	$ 2,058,875	$ 642,826	72,590	2,774,291
March	$ 2,102,188	$ 675,733	79,150	2,857,071
April	2,815,680	901,310	95,284	3,812,274
May	2,071,757	753,166	67,516	2,892,439
June	2,090,931	394,111	71,981	2,557,023
July	2,030,515	681,741	70,249	2,782,506
August	1,995,822	714,825	72,507	2,783,154
September	2,553,295	823,566	83,293	3,460,154
October	1,994,402	829,031	9,958	2,833,391
November	1,961,178	401,204	55,469	2,417,851
December	2,071,379	768,543	(17,898)	2,822,024
Total	**$ 26,089,397**	**$ 8,134,442**	**$ 746,639**	**$ 34,970,478**

A See 12ME DEC 2016 tab for department detail, by month.
B See 12ME DEC 2017 tab for department detail, by month.
C See 12ME DEC 2018 tab for department detail, by month.
D See 9ME SEP 2019 tab for department detail, by month.
E See 2019 (Budget) tab for department detail, by month.
F See 2020 (Budget) tab for department detail, by month.

EXHIBIT ____ (LK-11)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-007

REQUEST:

Refer to the Direct Testimony of Retha Hunsicker ("Hunsicker Direct") discussing the new Customer Connect customer service platform being developed by DEBS. The following questions relate to the Customer Connect platform and program costs incurred or projected to be incurred and what has been included in the test year.

a. Provide the amount of capital expenditures, plant additions, depreciation expense, return on assets, and all other either directly incurred by DEK and/or allocated to it from DEBS for each historic year in which actual costs were incurred, projected for base year, projected for the test year, and projected for each year thereafter until the new project is expected to be completed.

b. Provide the amount of O&M expenses, either directly incurred by DEK and/or allocated to it from DEB for each historic year in which costs were incurred, projected for base year, projected for the test year, and projected for each year thereafter until the new project is expected to be completed. If any O&M costs have been deferred or are expected to be deferred for any reason, provide the amounts and describe the deferrals.

c. Provide a calculation of the Customer Connect revenue requirement. Provide all detail, including all rate base components and amounts and all expense components and amounts, and all calculations that sum to the revenue requirement.

RESPONSE:

a. See STAFF-DR-02-034 for actual costs incurred in 2016-2018. Capital placed in service for the base period and test period is $1.164 million and $1.457 million, respectively. The Company has not calculated depreciation expense and property taxes or a return specifically for these assets.

b. See STAFF-DR-02-034 for actual costs incurred in 2016-2018. O&M in the base period and test period is $941,777 and $908,818, respectively.

c. The Company has not made this calculation.

PERSON RESPONSIBLE: Retha Hunsicker
Sarah E. Lawler

EXHIBIT ____ (LK-12)

AG-DR-02-012

REQUEST:

Refer to the Company's response to AG-DR-01-007, which sought information related to the Customer Connect costs included in the revenue requirement.

a. Provide the amount of Customer Connect plant in service by month from March 2020 through March 2021 reflected in rate base or explain why the Company cannot provide this information.

b. Provide the amount of Customer Connect accumulated depreciation by month from March 2020 through March 2021 reflected in rate base or explain why the Company cannot provide this information.

c. Provide the amount of Customer Connect ADIT by month from March 2020 through March 2021 reflected in rate base or explain why the Company cannot provide this information.

d. Provide the amount of Customer Connect depreciation expense by month for the test year included in the revenue requirement. Provide the calculation of this expense in electronic spreadsheet live format with all formulas intact.

e. Provide the amount of Customer Connect ad valorem expense by month for the test year included in the revenue requirement. Provide the calculation of this expense in electronic spreadsheet live format with all formulas intact.

f. Provide the amount of Customer Connect payroll tax expense by month for the test year included in the revenue requirement.

RESPONSE:

a. See AG-DR-02-012 Attachment.

b. See AG-DR-02-012 Attachment.

c. See AG-DR-02-012 Attachment.

d. See AG-DR-02-012 Attachment.

e. See AG-DR-02-012 Attachment.

f. Forecasted payroll tax in the test period related to Customer Connect is $1,049 per month April 2020-December 2020 and $594 per month January 2021-March 2021.

After estimating all of these components, the Company estimates the revenue requirement included in the test period to be approximately $200,000.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Estimated Revenue Requirement
Customer Connect Project

Line	Description	Test Period
1	Gross Plant[a]	$1,456,637
2	Accum Depreciation [b]	(67,806)
3	Net Plant in Service	$1,388,831
4	Accum Def Income Taxes on Plant [b]	($46,939)
5	Rate Base	**$1,341,891**
6	Return on Rate Base (Pre-Tax %) [c]	8.96%
7	Return on Rate Base (Pre-Tax)	$120,193
8	Depreciation Expense	67,806
9	Annualized Property Tax Expense	12,221
10	Revenue Requirement (Lines 7 - 9)	$200,221

Assumptions:

[a] 13 month average based on project costs and estimated in-service dates

[b] Assumes 10.74 year book life; 5 year MACRS

[c] Weighted-Average Cost of Capital from Schedule A in Case No. 2019-00271, with ROE at 9.8%, grossed up for 21% FIT rate.

Customer Connect estimate

Month	Customer Connect In-service balance	Depreciation Expense	Accumulated Depreciation	ADIT
Mar-20	1,444,642	5,651	5,651	3,912
Apr-20	1,444,642	5,651	11,301	3,912
May-20	1,444,642	5,651	16,952	3,912
Jun-20	1,444,642	5,651	22,602	3,912
Jul-20	1,444,642	5,651	28,253	3,912
Aug-20	1,444,642	5,651	33,903	3,912
Sep-20	1,444,642	5,651	39,554	3,912
Oct-20	1,444,642	5,651	45,204	3,912
Nov-20	1,444,642	5,651	50,855	3,912
Dec-20	1,483,627	5,651	56,505	3,912
Jan-21	1,483,627	5,651	62,156	3,912
Feb-21	1,483,627	5,651	67,806	3,912
Mar-21	1,483,627	11,301	79,108	9,696

13 Month Average:	$1,456,637
Depreciation rate:	9.31%
Annual Depreciation Expense	$135,612.90
1st year is half year	$67,806.45

Customer Connect property tax estimate

Month	In-service balance (hardware only)	Property Tax Expense
Apr-20	886,947	936
May-20	886,947	936
Jun-20	886,947	936
Jul-20	886,947	936
Aug-20	886,947	936
Sep-20	886,947	936
Oct-20	886,947	936
Nov-20	886,947	936
Dec-20	886,947	936
Jan-21	1,185,385	1,264
Feb-21	1,185,385	1,264
Mar-21	1,185,385	1,264

Property Tax Rate - 2020	1.267%
Property Tax Rate - 2021	1.280%
Test Period Expense	$12,221

Note that property tax expense is calculated on prior year tangible plant

Duke Energy Kentucky
Customer Connect Plant In-Service

Line	Description	Test Period												
		Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
1	Placed In Service	1,444,642									38,984			
2	Culmative Plant In Service	1,444,642	1,444,642	1,444,642	1,444,642	1,444,642	1,444,642	1,444,642	1,444,642	1,444,642	1,483,627	1,483,627	1,483,627	1,483,627
3	13 Month Average (Average of Ln 2):	$1,456,637												

Duke Energy Kentucky

Project	Property, Plant and Equipment (Capital)						
	2020	2021	2022	2023	2024	2025	2026
CIS Program	$1,456,637	$0	$0	$0	$0	$0	$0
Cumulative Gross Plant	1,456,637	1,456,637	1,456,637	1,456,637	1,456,637	1,456,637	1,456,637
Depreciation Expense	67,806	$135,613	$135,613	$135,613	$135,613	$135,613	$135,613
Accumulated Depreciation	($67,806)	($203,419)	($339,032)	($474,645)	($610,258)	($745,871)	($881,484)
Accumulated Deferred Income Tax	($46,939)	($116,347)	($146,600)	($153,360)	($160,120)	($149,261)	($120,782)

Book Life	Tax Life
10.74	5.00

	5 Yr MACRS	Cap Additions	Tax Depreciation on 2019 Spend	2020 Spend	2021 Spend	2022 Spend	2023 Spend	Total Tax Depr	Book Depreciation	Gross Plant	Accumulated Depreciation	Deferred Tax	ADIT
2020	20.00%	$1,456,637	$291,327					291,327	$67,806	1,456,637	$67,806	46,939	$46,939
2021	32.00%	-	466,124	$0				466,124	135,613	1,456,637	203,419	69,407	116,347
2022	19.20%	-	279,674	-	$0			279,674	135,613	1,456,637	339,032	30,253	146,600
2023	11.52%	-	167,805	-	-	$0		167,805	135,613	1,456,637	474,645	6,760	153,360
2024	11.52%	-	167,805	-	-	-	$0	167,805	135,613	1,456,637	610,258	6,760	160,120
2025	5.76%	-	83,902	-	-	-	-	83,902	135,613	1,456,637	745,871	(10,859)	149,261
2026		-	-	-	-	-	-	-	135,613	1,456,637	881,484	(28,479)	120,782
	100.0%	$1,456,637	$1,456,637	$0	$0	$0	$0	$1,456,637	$881,484			$120,782	

EXHIBIT ____ (LK-13)

REVISED DIRECT TESTIMONY OF CHRISTA L. GRAFT
LEAD RATES & REGULATORY STRATEGY ANALYST
DUKE ENERGY INDIANA, LLC
BEFORE THE INDIANA UTILITY REGULATORY COMMISSION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Christa L. Graft, and my business address is 1000 East Main Street, Plainfield, Indiana.

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

A. I am employed by Duke Energy Indiana, LLC ("Duke Energy Indiana," "Petitioner," or "Company") as a Lead Rates & Regulatory Strategy Analyst.

Q. PLEASE DESCRIBE YOUR DUTIES AS A LEAD RATES & REGULATORY STRATEGY ANALYST.

A. As a Lead Rates & Regulatory Strategy Analyst, I am responsible for the preparation of financial and accounting data used in Company rate filings.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I graduated from Indiana University in May 1998 with a Bachelor of Science degree in Business with a major in Accounting. I have been employed by the Company since June 1998 and have held various financial and accounting positions supporting the Company and its affiliates. My first position was as an Analyst in the External Reporting department, where my responsibilities included various quarterly and annual Securities and Exchange Commission and Federal Energy Regulatory Commission ("FERC") filings. In 2000, I was promoted to a Senior Analyst position in the Accounting Research with the complete set of base rate and other rider tariffs that are filed with the testimony of Mr. Flick as Petitioner's Exhibit 9-A (RAF) (clean) and 9-B (RAF) (red-lined). As discussed in more detail by Ms. Douglas, a complete set of all revised tariff pages will be filed for Commission approval with the Step 1 Base Rate Compliance filing in mid-2020, reflecting the changes in the then-current rates due to the Commission's findings related to base rates and including the use of the allocation factors approved in this proceeding.

IV. DEFERRAL AND COST RECOVERY REQUESTS

A. Customer Connect

Q. WHAT IS THE COMPANY'S CUSTOMER CONNECT PROJECT?

A. As discussed in the testimony of Duke Energy Indiana witness Ms. Retha I. Hunsicker, the Company is deploying a new customer platform as part of its customer information system consolidation project known as Customer Connect. Customer Connect is a multi-year, multi-jurisdictional project that will allow the Company to deliver a customer experience that will simplify, strengthen and advance its ability to serve customers.

Q. WHAT IS THE PROJECTED COST OF THE CUSTOMER CONNECT PROJECT TO THE COMPANY?

A. As discussed by Ms. Hunsicker, the projected cost of Customer Connect to Duke Energy Indiana is approximately $90-$95 million over the 2016-2023 time period, which is comprised of approximately half capital spend and half O&M and payroll tax spend.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE CAPITAL COSTS FOR THE CUSTOMER CONNECT PROJECT?

A. There are multiple components to the capital portion of the Customer Connect project that are being placed in-service as they are completed and functional. Capital components that are in-service as of the end of the Test Period will be included in the base rates proposed in this proceeding. For capital components that are not in-service as of the end of the Test Period, the Company is proposing to defer depreciation expense and post-in-service carrying costs at the weighted average cost of capital rate as regulatory assets until these capital components are deemed to be used and useful in a future rate case.

Q. HOW DOES THE COMPANY PROPOSE TO RECOVER THE O&M AND PAYROLL TAX COSTS FOR THE CUSTOMER CONNECT PROJECT?

A. The Company is proposing to defer O&M and payroll tax costs incurred from 2018 and forward for the development and implementation of the core billing system, with carrying costs at the weighted average cost of capital rate, as a regulatory asset to be held for recovery in a future rate case. The amount of O&M and payroll tax costs to be deferred, excluding carrying costs, is currently estimated at approximately $42 million. The Company is not proposing any recovery for O&M and payroll tax costs incurred in 2016 and 2017.

Q. IS THE COMPANY'S RATEMAKING PROPOSAL REASONABLE?

A. Yes. The Customer Connect project is a significant investment that will benefit Duke Energy Indiana customers for many years to come, and it is reasonable and prudent to allow the Company to defer the associated costs for future rate case recovery.

EXHIBIT ____ (LK-14)

REQUEST:

Refer to the Direct Testimony of Lesley Quick ("Quick Direct"), pages 8–13.

a. Provide the percentage of total residential customer payments via credit/debit card and electronic check assumed in the test year.

b. Provide the percentage of total customer payments via credit/debit card and electronic check assumed in the test year.

c. Provide the residential uncollectible accounts expense by FERC account incurred in each year 2016–2018, in the base year, and in the test year.

e. Indicate whether the Company reduced the uncollectible accounts expense to reflect the increase in revenues collected via credit card in the test year. If so, indicate where the Company made this adjustment and provide the calculations, including electronic spreadsheets in live format with all formulas intact. If not, explain why the Company did not do so.

f. Indicate whether the Company reduced the discount in proceeds from the sale of the Company's receivables to reflect the increase in revenues collected via credit card in the test year. If so, indicate where the Company made this adjustment and provide the calculations, including electronic spreadsheets in live format with all formulas intact. If not, explain why the Company did not do so.

g. Indicate whether the Company reduced the cost to process cash, checks, money orders, and automated bank drafts (ACH) to reflect the increase in transactions and revenues collected via credit card in the test year. If so, indicate where the Company made this adjustment and provide the calculations, including electronic spreadsheets in live format with all formulas intact. If not, explain why the Company did not do so.

RESPONSE:

a. Duke Energy Kentucky does not have this data broken out for just residential by those categories for the test year.

b. Approximately 19% of customers pay by electronic check and 81% pay by credit/ debit card.

c. Duke Energy Kentucky sells all, at a discount and without recourse, of its retail receivables to CRC, a bankruptcy remote, special purpose entity indirectly owned by Duke Energy. As such, Duke Energy Kentucky does not record uncollectible expense.

d. No part (d).

e. There was no manual adjustment to the uncollectible accounts expense because the impact, if any, is not known at this time.

f. There was no manual adjustment to the uncollectible accounts proceeds because the impact, if any, is not known at this time.

g. There was no manual adjustment because the impact, if any, is not known at this time.

PERSON RESPONSIBLE: Leslie Quick – a. b.
Danielle Weatherston – c.
Sarah E. Lawler – e. thru g.

EXHIBIT ____ (LK-15)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-044

REQUEST:

Provide the amount of Supplemental Executive Retirement Plan ("SERP") costs included in the test year O&M expenses. Provide the amounts broken down between DEK directly incurred costs and costs allocated separately from each other affiliate.

RESPONSE:

See AG-DR-01-044 Attachment.

PERSON RESPONSIBLE: Renee H. Metzler

44. Provide the amount of Supplemental Executive Retirement Plan ("SERP") costs included in the test year O&M expenses. Provide the amounts broken down between DEK directly incurred costs and costs allocated separately from each other affiliate.

Test period: 4/1/20 - 3/31/21

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
DEK BUDGET for NQ Plans - Direct - 2020	-	-	-	705	705	705	705	705	705	705	705	705	6,343
DEK BUDGET for NQ Plans - Alloc - 2020	-	-	-	9,472	9,472	9,472	9,472	9,472	9,472	9,472	9,472	9,472	85,245
DEK BUDGET for NQ Plans - Direct - 2021	701	701	701	-	-	-	-	-	-	-	-	-	2,103
DEK BUDGET for NQ Plans - Alloc - 2021	9,277	9,277	9,277	-	-	-	-	-	-	-	-	-	27,830
TOTAL DEK BUDGET for NQ Plans - Direct (4/1/20 - 3/31/21)													8,446
TOTAL DEK BUDGET for NQ Plans - Alloc (4/1/20 - 3/31/21)													113,075
TOTAL DEK BUDGET for NQ Plans (4/1/20 - 3/31/21)													121,521

Assumptions:

1) Service and Non Service costs are included in the above numbers
2) Source for numbers = Towers Watson five year financial plan report
3) Direct numbers are calculated based on annual budget for DEK Electric
4) Allocated numbers are calculated based on annual budget for DEBs (using DGEX Allocation % to DEK Electric)

EXHIBIT ____ (LK-16)

THIS FILING IS

Item 1: ☐ An Initial (Original) Submission OR ☒ Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2018/Q4

(f) Represents funds received from customers to cover future removal of property, plant and equipment from retired or abandoned sites as property is retired. Included in rate base and recovered over the life of associated assets.

(g) Certain amounts are recovered through rates.

RATE RELATED INFORMATION

The KPSC approves rates for retail electric and natural gas services within the Commonwealth of Kentucky. The FERC approves rates for electric sales to wholesale customers served under cost-based rates, as well as sales of transmission service.

Duke Energy Kentucky Electric Rate Case

On September 1, 2017, Duke Energy Kentucky filed a rate case with the KPSC requesting an increase in electric base rates of approximately $49 million, which represents an approximate 15 percent increase on the average customer bill. Subsequent to the filing, Duke Energy Kentucky adjusted the requested amount to $30.1 million, in part to reflect the benefits of the Tax Act, representing an approximate 9 percent increase on the average customer bill. The rate increase was driven by increased investment in utility plant, increased operations and maintenance expenses and recovery of regulatory assets. The application also includes requests to implement an Environmental Surcharge Mechanism to recover environmental costs not recovered in base rates, to establish a Distribution Capital Investment Rider to recover incremental costs of specific programs, to establish a FERC Transmission Cost Reconciliation Rider to recover escalating transmission costs and to modify existing Profit Sharing Mechanism to increase customers' share of proceeds from the benefits of owning generation and to mitigate shareholder risks associated with that generation. An evidentiary hearing concluded on March 8, 2018, and the KPSC issued an order on April 13, 2018. Major components of the order include approval of an $8 million increase in base rates with a return on equity at 9.725 percent based upon a capital structure of 49 percent equity on a total allocable capitalization of approximately $650 million. The order approved the Environmental Surcharge Mechanism Rider and in June 2018 recovery began of capital-related environmental costs, including costs related to ash and ash disposal, and environmental operation and maintenance expenses formerly recovered in base rates, including expenses for environmental reagents and emission allowances. The incremental revenue from this rider will be approximately $13 million on an annualized basis. The order settles all issues associated with the Tax Act as it relates to the electric business by lowering the income tax component of the revenue requirement and refunding protected EDIT under allowable normalization rules and unprotected EDIT over 10 years. The order denied requests to implement riders for certain transmission costs and distribution capital investments. Duke Energy Kentucky implemented new base rates on May 1, 2018. On May 3, 2018, Duke Energy Kentucky filed an application for rehearing on certain aspects of the order; on May 23, 2018, the KPSC granted a rehearing. On October 2, 2018, the KPSC issued its rehearing order correcting certain findings in its initial order and making additional changes that are immaterial to the company's earnings.

Duke Energy Kentucky Natural Gas Base Rate Case

On August 31, 2018, Duke Energy Kentucky filed an application with the KPSC requesting an increase in natural gas base rates of approximately $11 million, an approximate 11.1 percent average increase across all customer classes. The increase is net of approximately $5 million in annual savings as a result of the Tax Act. The drivers for this case are capital invested since Duke Energy Kentucky's last rate case in 2009. Duke Energy Kentucky is also seeking implementation of a Weather Normalization Adjustment Mechanism, amortization of regulatory assets and to implement the impacts of the Tax Act, prospectively. On January 30, 2019, Duke Energy Kentucky entered into a settlement agreement with the Attorney General of Kentucky, the only intervenor in the case, which if approved would resolve the matter. The settlement provides for an approximate $7 million increase and approval of the proposed Weather Normalization Mechanism. A hearing was held on February 5, 2019. A ruling is expected in late first quarter 2019. Duke Energy Kentucky cannot predict the outcome of this matter.

FERC 494 Refund of Regional Transmission Enhancement Projects

FERC Order No. 494 Settlement Agreement (FERC 494 Settlement Agreement) was entered into by most of the PJM transmission owners, including Duke Energy Kentucky, and the PJM state regulatory commissions approximately two years ago and was planned to be effective on January 1, 2016; however, it was not approved by the FERC until May 31, 2018. The FERC 494 Settlement Agreement was due to the Seventh Circuit Court of Appeals finding that the FERC had failed to adequately justify the costs that the customers in the western part of PJM were being charged for high voltage transmission projects, or Regional Transmission Expansion Plan (RTEP) projects (500 kV and above) built in the east. These costs were being allocated to all PJM customers on a load-ratio share basis but the court determined that these costs were not justifiable to customers in the west, including Duke Energy Kentucky, that did not benefit from the RTEP projects. Costs for the periods 2012 through 2015 are expected to be refunded to Duke Energy Kentucky on a monthly basis through December 2025. The refund amount for similar costs incurred beginning in 2016 through June 30, 2018, prior to the change in cost allocation by PJM was determined in the third quarter of 2018 and these amounts will be refunded over a 12-month period beginning in July 2018. These refunds, totaling approximately $8 million for Duke Energy Kentucky have been recorded to Operation, maintenance and other on the Statements of Operations for the year ended December 31, 2018.

EXHIBIT ____ (LK-17)

REQUEST:

Refer to the following excerpt from DEK's 2018 FERC Form 1 at page 123.11:

FERC 494 Refund of Regional Transmission Enhancement Projects

FERC Order No. 494 Settlement Agreement (FERC 494 Settlement Agreement) was entered into by most of the PJM transmission owners, including Duke Energy Kentucky, and the PJM state regulatory commissions approximately two years ago and was planned to be effective on January 1, 2016; however, it was not approved by the FERC until May 31, 2018. The FERC 494 Settlement Agreement was due to the Seventh Circuit Court of Appeals finding that the FERC had failed to adequately justify the costs that the customers in the western part of PJM were being charged for high voltage transmission projects, or Regional Transmission Expansion Plan (RTEP) projects (500 kV and above) built in the east. These costs were being allocated to all PJM customers on a load-ratio share basis but the court determined that these costs were not justifiable to customers in the west, including Duke Energy Kentucky, that did not benefit from the RTEP projects. Costs for the periods 2012 through 2015 are expected to be refunded to Duke Energy Kentucky on a monthly basis through December 2025. The refund amount for similar costs incurred beginning in 2016 through June 30, 2018, prior to the change in cost allocation by PJM was determined in the third quarter of 2018 and these amounts will be refunded over a 12-month period beginning in July 2018. These refunds, totaling approximately $8 million for Duke Energy

Kentucky have been recorded to Operation, maintenance and other on the Statements of Operations for the year ended December 31, 2018.

a. Provide the amounts of the FERC Order No. 494 refunds recorded by subaccount by month starting in 2018 through the present month and projected through December 2025 associated with RTEP costs for the periods 2012 through 2015.

b. Provide the amounts of the FERC Order No. 494 refunds projected for the test year and included in the instant case filing by subaccount by month associated with RTEP costs for the periods 2012 through 2015. If no refunds were projected for the test year, explain why not since the notation describes refunds through 2025.

c. Provide the amounts of the FERC Order No. 494 refunds recorded by subaccount by month starting in 2018 through the present month and projected through the end of the test year associated with RTEP costs for the periods 2016 through June 30, 2018.

d. Indicate whether or not any FERC Order No. 494 refunds associated with RTEP costs for the periods 2016 through June 30, 2018 are included as reductions to test year costs. If so, indicate the subaccount in which these refunds are reflected and the amount in the test year. If not, explain why not.

e. Explain all reasons why the Company did not seek to return the FERC Order No. 494 refunds amounts associated with RTEP costs to customers as part of the instant case or another filing. If the refunds were flowed through to ratepayers in part or in whole via the fuel adjustment clause or other rider, describe in detail.

RESPONSE:

a. The RTEP costs for the period 2012 through 2015 have not been recovered from customers; so, the refunds are for costs borne exclusively by the shareholders. As such, any refund received should likewise belong to the shareholder. In May 2018, $4.1 million was credited to account 0561800 related to an estimate of the total FERC Order No. 494 refunds for the period 2012 through 2015. As the refunds are received, they will relieve the receivable set-up when the amount was recorded to account 0561800.

b. No refunds are included in the forecasted test year associated with FERC Order No. 494 refunds of RTEP costs incurred for the periods 2012 through 2015. Please see response to (e) below for the explanation why there weren't any projected refunds included in the test year.

c. In August 2018, an additional $3.9 million was credited to 0561800 for an estimate of the total FERC Order No. 494 refunds for the period of January 2016 through June 2018. The RTEP costs for the period January 2016 through April 2018 were not recovered from customers; so, the refunds are for costs borne exclusively by the shareholders for 28 of the 30 months at issue. As the refunds were received, they relieved the receivable set-up when the amount was recorded to account 0561800.

d. No refunds are included in the forecasted test year associated with refunds of RTEP costs incurred for the periods January 1, 2016, through June 30, 2018. Refunds attributable to RTEP costs incurred for January 1, 2016, through April 30, 2018, were borne exclusively by shareholders; consequently, customers are not entitled to refunds of costs that were not being recovered in rates. Please see the response to (e) below for a proposed correction to the Company's test year revenue requirement to address refunds attributable to May and June 2018.

e. From January 1, 2012, through April 30, 2018, the Company has incurred RTEP costs that have not been recovered from customers and will not be recovered from customers. It would be inappropriate and contrary to ratemaking principals to refund customers dollars for expenses incurred by the Company that were never collected from customers. Per response to AG-DR-02-034, RTEP charges were not included in electric base rates until May 1, 2018, the effective date of new base rates approved in Case No. 2017-00321. Therefore, May and June of 2018 are the only months associated with the FERC Order No. 494 refunds that customers were charged RTEP. The refund associated with this period is $260,022. The Company proposes to adjust its revenue requirement calculation to amortize this refund over a period of sixty months. The amortization period aligns with the amortization period for other one-time expenses being amortized such as rate case expense.

PERSON RESPONSIBLE: Danielle L. Weatherston – a., c.
Christopher M. Jacobi – a. thru c.
Sarah E. Lawler – d., e.

EXHIBIT ____ (LK-18)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's Second Set Data Requests
Date Received: November 12, 2019

AG-DR-02-034

REQUEST:

Refer to the response to Staff-DR-02-060 which mentioned the FERC Order No. 494 refunds "for RTEP charges incurred by the Company in prior periods that were never charged to customers in base rates or any riders."

a. Explain this statement. As part of the response, provide the amounts of DEK RTEP charges that were charged to customers on a monthly basis through the most recent month with available data.

b. Identify the month when new rates went into effect related to Case No. 2017-00321.

c. Prior to the change in base rates associated with Case No. 2017-00321, identify when rates were last updated and cite the related case number.

d. Provide the amount of transmission expenses in Accounts 560-574 that were included in rates, base rates and other, for each of the years 2013 through 2019. If amounts changed during any year, such as 2018, notate amounts before and after the change.

e. Provide the authorized earned rate of return for DEK for each of the years 2013 through 2018 and the actual earned rate of return experienced in each of those same years.

RESPONSE:

a. RTEP charges were not included in the Company's test year revenue requirement in Case No. 2006-00172; so, from the first day Duke Energy Kentucky became a member of PJM through the date when new rates were implemented in Case No. 2017-00321, recovery from customers for RTEP costs was $0. The amount included in the approved revenue requirement for the forecasted test year used in Case No. 2017-00321 was $3,621,173 on an annual basis. Assuming the costs are recovered evenly throughout the year, the recovery for each month is shown in the table below.

RTEP Recovered from Retail Customers								
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Jan	$0	$0	$0	$0	$0	$0	$0	$301,764
Feb	0	0	0	0	0	0	0	301,764
Mar	0	0	0	0	0	0	0	301,764
Apr	0	0	0	0	0	0	0	301,764
May	0	0	0	0	0	0	$301,764	301,764
Jun	0	0	0	0	0	0	301,764	301,764
Jul	0	0	0	0	0	0	301,764	301,764
Aug	0	0	0	0	0	0	301,764	301,764
Sep	0	0	0	0	0	0	301,764	301,764
Oct	0	0	0	0	0	0	301,764	301,764
Nov	0	0	0	0	0	0	301,764	301,764
Dec	0	0	0	0	0	0	301,764	301,764

b. May 1, 2018.

c. January 2, 2007, pursuant to the Commission's order in Case No. 2006-00172.

d. The base rates approved in Case No. 2006-00172 included recovery of $16,939,554 in transmission costs (Accounts 560-574). This is the annualized amount of recovery from 2007 through April 2018.

The base rates approved in Case No. 2017-00321 included an annualized level of $19,523,753. This is the annualized amount that will be recovered in base rates until the Commission approves new base rates in this application.

e. The authorized rate of return for 2013 through April 30, 2018 is 8.358% per the order in Case No. 2006-00172 and 6.830% for May 1, 2018 to current per the order in Case No. 2017-00321. See response to AG-DR-02-052 for the actual earned rate of returns.

PERSON RESPONSIBLE: William Don Wathen Jr. – a. thru e.
Danielle L. Weatherston – e.

EXHIBIT ____ (LK-19)

THIS FILING IS

Item 1: [X] An Initial (Original) Submission OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2013/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	322,726	305,660
63	(547) Fuel	918,422	1,202,379
64	(548) Generation Expenses	246,770	294,809
65	(549) Miscellaneous Other Power Generation Expenses	646,794	703,096
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,134,712	2,505,944
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	87,668	37,084
70	(552) Maintenance of Structures	714,371	576,342
71	(553) Maintenance of Generating and Electric Plant	276,068	3,146,594
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	118,299	177,492
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,196,406	3,937,512
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	3,331,118	6,443,456
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	45,990,717	53,912,270
77	(556) System Control and Load Dispatching		
78	(557) Other Expenses	4,971,062	4,009,798
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	50,961,779	57,922,068
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	188,292,296	187,042,138
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	18,154	19,822
84			
85	(561.1) Load Dispatch-Reliability	79,077	82,314
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	106,082	124,689
87	(561.3) Load Dispatch-Transmission Service and Scheduling	14,728	17,333
88	(561.4) Scheduling, System Control and Dispatch Services	117,701	137,114
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		-26
93	(562) Station Expenses	119,495	99,625
94	(563) Overhead Lines Expenses	44,712	40,881
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	8,944,811	11,169,053
97	(566) Miscellaneous Transmission Expenses	130,672	201,817
98	(567) Rents		701,774
99	TOTAL Operation (Enter Total of lines 83 thru 98)	9,575,432	12,594,396
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	11	
102	(569) Maintenance of Structures	11,359	9,366
103	(569.1) Maintenance of Computer Hardware	16,670	15,655
104	(569.2) Maintenance of Computer Software	71,029	141,396
105	(569.3) Maintenance of Communication Equipment	1,386	4,460
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	304,018	390,270
108	(571) Maintenance of Overhead Lines	225,835	295,028
109	(572) Maintenance of Underground Lines	24,026	25,860
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	654,334	882,035
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	10,229,766	13,476,431

THIS FILING IS

Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
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Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2014/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2015	End of 2014/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	338,833	322,726
63	(547) Fuel	3,634,500	918,422
64	(548) Generation Expenses	202,828	246,770
65	(549) Miscellaneous Other Power Generation Expenses	1,173,830	646,794
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,349,991	2,134,712
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	49,536	87,668
70	(552) Maintenance of Structures	502,459	714,371
71	(553) Maintenance of Generating and Electric Plant	266,446	276,068
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	182,642	118,299
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,001,083	1,196,406
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,351,074	3,331,118
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	94,919,008	45,990,717
77	(556) System Control and Load Dispatching	510	
78	(557) Other Expenses	6,755,666	4,971,062
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	101,675,184	50,961,779
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	227,245,343	188,292,296
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,225	18,154
84			
85	(561.1) Load Dispatch-Reliability	86,039	79,077
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	385,000	106,082
87	(561.3) Load Dispatch-Transmission Service and Scheduling	52,420	14,728
88	(561.4) Scheduling, System Control and Dispatch Services		117,701
89	(561.5) Reliability, Planning and Standards Development	5,516	
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	98,548	119,495
94	(563) Overhead Lines Expenses	83,162	44,712
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	11,958,297	8,944,811
97	(566) Miscellaneous Transmission Expenses	286,930	130,672
98	(567) Rents	935	
99	TOTAL Operation (Enter Total of lines 83 thru 98)	12,959,072	9,575,432
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	11	11
102	(569) Maintenance of Structures	7,273	11,359
103	(569.1) Maintenance of Computer Hardware	19,511	16,670
104	(569.2) Maintenance of Computer Software	151,035	71,029
105	(569.3) Maintenance of Communication Equipment		1,386
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	315,030	304,018
108	(571) Maintenance of Overhead Lines	361,344	225,835
109	(572) Maintenance of Underground Lines	29,132	24,026
110	(573) Maintenance of Miscellaneous Transmission Plant	5	
111	TOTAL Maintenance (Total of lines 101 thru 110)	883,341	654,334
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	13,842,413	10,229,766

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2016/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/13/2017	End of 2016/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	387,652	381,215
63	(547) Fuel	2,274,241	5,426,433
64	(548) Generation Expenses	272,293	287,728
65	(549) Miscellaneous Other Power Generation Expenses	1,036,079	1,134,516
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,970,265	7,229,892
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	43,717	14,590
70	(552) Maintenance of Structures	458,636	348,973
71	(553) Maintenance of Generating and Electric Plant	2,545,942	540,800
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	188,372	177,438
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,236,667	1,081,801
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,206,932	8,311,693
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	41,650,445	32,566,220
77	(556) System Control and Load Dispatching	1,080	868
78	(557) Other Expenses	13,422,745	5,932,609
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	55,074,270	38,499,697
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	186,570,859	195,643,840
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,132	7,699
84			
85	(561.1) Load Dispatch-Reliability	104,843	101,477
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	490,530	405,611
87	(561.3) Load Dispatch-Transmission Service and Scheduling	68,624	55,813
88	(561.4) Scheduling, System Control and Dispatch Services	1,460,340	
89	(561.5) Reliability, Planning and Standards Development	470	902
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	107,358	116,017
94	(563) Overhead Lines Expenses	16,744	103,310
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	15,553,606	14,117,924
97	(566) Miscellaneous Transmission Expenses	629,025	409,751
98	(567) Rents	1,668	618
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,436,340	15,319,122
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	39,988	21,868
103	(569.1) Maintenance of Computer Hardware	2,499	1,182
104	(569.2) Maintenance of Computer Software	199,640	262,370
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	329,419	279,482
108	(571) Maintenance of Overhead Lines	409,659	299,887
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	981,205	864,789
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	19,417,545	16,183,911

THIS FILING IS	
Item 1: ☐ An Initial (Original) Submission	OR ☒ Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
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FERC FINANCIAL REPORT
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Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Kentucky, Inc.	End of 2018/Q4

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Kentucky, Inc.	(1) [ ] An Original (2) [X] A Resubmission	04/26/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	392,525	409,170
63	(547) Fuel	8,541,559	1,920,479
64	(548) Generation Expenses	342,235	334,915
65	(549) Miscellaneous Other Power Generation Expenses	948,145	965,092
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	10,224,464	3,629,656
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	206,662	84,829
70	(552) Maintenance of Structures	392,714	280,302
71	(553) Maintenance of Generating and Electric Plant	247,356	2,387,546
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	326,663	296,614
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,173,395	3,049,291
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	11,397,859	6,678,947
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	75,625,084	31,557,546
77	(556) System Control and Load Dispatching	1,460	1,246
78	(557) Other Expenses	2,538,182	6,225,805
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	78,164,726	37,784,597
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	199,379,255	171,676,208
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,518	2,789
84			
85	(561.1) Load Dispatch-Reliability	93,821	94,788
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	435,265	435,117
87	(561.3) Load Dispatch-Transmission Service and Scheduling	59,242	59,082
88	(561.4) Scheduling, System Control and Dispatch Services	3,046,615	1,877,059
89	(561.5) Reliability, Planning and Standards Development		1,424
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	-6,392,346	666,832
93	(562) Station Expenses	148,685	111,250
94	(563) Overhead Lines Expenses	33,532	46,121
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	13,909,634	12,797,078
97	(566) Miscellaneous Transmission Expenses	486,517	481,220
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	11,823,483	16,572,760
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	29,250	8,929
103	(569.1) Maintenance of Computer Hardware	1,011	615
104	(569.2) Maintenance of Computer Software	134,506	97,287
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	255,031	335,680
108	(571) Maintenance of Overhead Lines	428,751	230,761
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,108	
111	TOTAL Maintenance (Total of lines 101 thru 110)	850,657	673,272
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	12,674,140	17,246,032

EXHIBIT ____ (LK-20)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-050

REQUEST:

Refer to the DEBS 2018 FERC Form 60 at pages 201, 301, and 302.

a. Refer to the amount of net income after taxes reflected on page 302 at line 62 and the amount of income taxes on page 302 at lines 42-44. Explain how the service company reflected net income of approximately $36.105 million after net income tax expense of approximately $15.407 million in 2018 as opposed to net income and income taxes at around zero if all costs were charged to affiliates at cost.

b. Refer to page 201 at lines 14 and 15. The balance of Unappropriated Retained Earnings at the end of 2018 was approximately $508.533 million and dividends paid during 2018 were $0. Confirm that the amount of Unappropriated Retained Earnings represents profits retained at DEBS, after annual dividends to stockholders, and that those profits represent billings to affiliates in excess of actual costs on a cumulative basis.

c. Are any costs charged to affiliates, such as DEK, based on an equity return on investment component as opposed to just the return of component and interest charges? If so, explain and describe the basis for the equity return added to costs charged to affiliates as well as the actual return on equity percentage added during 2018 and the projected return on equity percentage for the test year.

d. Provide a schedule showing the monthly forecasted net income for DEBS, before and after income taxes, for each month during 2020 and the first three months of 2021.

e. Provide a schedule showing the monthly forecasted recovery of equity return for DEBS, including income taxes, charged to DEK, including charges directly to DEK from DEBS and all charges from other affiliates that include charges from DEBS. Provide all calculations, including electronic spreadsheets in live format with all formulas intact.

RESPONSE:

a. The Service Company charges a return for the use of DEBS assets to the jurisdictions. This represents a cost of capital for assets on the Service Company that are used in the operations of Duke Energy and its subsidiary companies. For 2018, the return on DEBS assets was $51.3 million, income tax expense was $15.4 million, resulting in net income of approximately $35.9 million.

b. The amount of Unappropriated Retained Earnings does represent billings in excess of costs recorded on DEBS ledger on a cumulative basis. The nature of these billings in excess of costs can be categorized into two categories. Prior to the Duke Cinergy merger, which brought Kentucky under Duke Energy Corporation, the legacy Duke Corporation utilized a tax strategy in which the Service Company charged a management fee for services provided. The cost to the utilities, primarily Duke Energy Carolinas, was recorded to a below the line non-utility account. The reorganization associated with the Duke Cinergy merger negated this strategy going forward. The second category is the return on DEBS assets. The Service Company to Utility Service Agreement states that the company shall cover all costs of doing business. Cost as defined in the agreement means "fully embedded costs, namely, the sum of (1) direct costs, (2) indirect costs and (3) **costs of capital**." The return on DEBS assets is a charge to recover the cost of capital to the utilities for the use of these assets.

c. A return on DEBS assets is recorded based on a monthly calculation of DEBS assets. These assets include PP&E, prepaid pension assets and inventory. The PP&E is determined based on NET PP&E less CWIP less associated deferred taxes. Prepaid pension assets are determined by taking the prepaid qualified pension, less the non-qualified pension and OPEB liabilities and decreasing by a deferred tax amount. The inventory amount is the amount reflected on the inventory balance sheet for DEBS. The total allocated amount of assets assigned to the Regulated Utility is multiplied by a revenue requirement percentage to achieve the allowed rate of return in the jurisdiction. The amount allocated to the utility is based on a 3-factor allocation for PP&E and inventory assets. The pension assets are allocated based on DEBS labor usage. This process is applicable to 2018, 2019 and for the projected test year. The revenue requirement percentage used in Kentucky are based on the 2017 Kentucky Electric rate case for all forecasted periods. See AG-DR-01-050(c) Attachment.

d. See table below:

Period	Before taxes ($000)	After taxes ($000)
Jan-20	4,440	2,894
Feb-20	4,440	2,894
Mar-20	4,440	2,894
Apr-20	4,440	2,894
May-20	4,440	2,894
Jun-20	4,440	2,894
Jul-20	4,440	2,894
Aug-20	4,440	2,894
Sep-20	4,440	2,894
Oct-20	4,440	2,894
Nov-20	4,440	2,894
Dec-20	4,440	2,894
Jan-21	4,481	2,926
Feb-21	4,481	2,926
Mar-21	4,481	2,926

e. Please see AG-DR-01-050(e) Attachment. This file includes multiple worksheets. The first worksheet "DEK Return" shows the monthly values for the forecasted test period for each of the components of the return as well as the total and tax effects. The following 3 worksheets for both 2020 and 2021 are the worksheets used to calculate the monthly values. Each worksheet shows the detailed calculations for the Duke Energy Kentucky electric component of the DEBS return that are linked to the "DEK Return" worksheet.

PERSON RESPONSIBLE: Jeff Setser (a,b,c,e)
Christopher Jacobi (d)

Duke Energy Kentucky, Inc.
Electric Case No. 2017-00321 10/2/2018

Capital Structure (b)						
Long Term Debt	268,420,548	40.977%	4.243%	1.739%	1.000000000	1.74%
Short Term Debt	64,011,655	9.772%	3.083%	0.301%	1.000000000	0.30%
Total Debt	332,432,203	50.749%		2.040%		
Preferred Stock		0.00%	0.00%	0.000%	1.340986600	0.00%
Common Equity	322,619,530	49.251%	9.725%	4.790%	1.340986600	6.42%
Total Jurisdictional Capit	655,051,733	100.00%		6.830%		8.460%
Rate Base	741,429,309					
Operating Income	44,740,032			6.034%		

Test Period PPE Return			Test Period PEN Return			Test Period INV Return			Total Return			After Tax Return				
4	2020	28,588	4	2020	32,046	4	2020	1,767	4	2020	62,400	4	2020	62,400	34.8%	40,672
5	2020	28,588	5	2020	32,046	5	2020	1,767	5	2020	62,400	5	2020	62,400	34.8%	40,672
6	2020	28,588	6	2020	32,046	6	2020	1,767	6	2020	62,400	6	2020	62,400	34.8%	40,672
7	2020	28,588	7	2020	32,046	7	2020	1,767	7	2020	62,400	7	2020	62,400	34.8%	40,672
8	2020	28,588	8	2020	32,046	8	2020	1,767	8	2020	62,400	8	2020	62,400	34.8%	40,672
9	2020	28,588	9	2020	32,046	9	2020	1,767	9	2020	62,400	9	2020	62,400	34.8%	40,672
10	2020	28,588	10	2020	32,046	10	2020	1,767	10	2020	62,400	10	2020	62,400	34.8%	40,672
11	2020	28,588	11	2020	32,046	11	2020	1,767	11	2020	62,400	11	2020	62,400	34.8%	40,672
12	2020	28,588	12	2020	32,046	12	2020	1,767	12	2020	62,400	12	2020	62,400	34.8%	40,672
1	2021	28,874	1	2021	32,366	1	2021	1,784	1	2021	63,024	1	2021	63,024	34.7%	41,152
2	2021	28,874	2	2021	32,366	2	2021	1,784	2	2021	63,024	2	2021	63,024	34.7%	41,152
3	2021	28,874	3	2021	32,366	3	2021	1,784	3	2021	63,024	3	2021	63,024	34.7%	41,152
		343,910			385,512			21,252			750,674			750,674		489,507

SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function	Allocation Method	Operating Unit	Alloc Pool	Co	DPC 20056 Duke Power Carolinas	DEP 50991 DE Progress	DEF 50992 Progress Florida	DEP	DEO	DEO	DEO	DEK	DEK	DEK	DEI 25060	Comm Pwr	Comm	Comm Trans	Gas Oper	Piedmont 47151 Piedmont Gas Del	Other	Other	Other	
Facilities Rate of Return Allocation	Allocates the Service Company's portion of	Three Factor Formula	DURR	Facilities ROR Svc		35.41%	23.35%	15.93%	0.04%	3.24%	1.59%	4.87%	1.02%	0.35%	1.37%	10.53%	2.99%	2.99%	0.02%	0.02%	5.47%	0.02%	0.04%	0.06%	100.00%

Account #	Res Type	Resp Center	Revenue Requirement (provided by each	DPC	DEP	DEF	DEP	DEO	DEO	DEO	DEK	DEK	DEK	DEI	Comm Pwr	Comm	Comm Trans	Gas Oper	Piedmont	Other	Other	Other	
											8.46%												
				12	12	12	12	12	12		12	12		12	12		12	12	12	12	12		
				0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.71%	0.00%		0.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%		
0931806 for expense	78000	8000 for expense																					
0456948 for income	78000	9957 for income		GO22	PCGS	PFGS	GO27	GO24	GO25		GO26	GO29		GO31	GO32		SG38	SG39	SG37	GO21	GO34		
		2020 PPE value:	397,548,155	1,120,309	670,679	404,253	1,214	99,180	48,250		28,566	10,728		270,589	34,596		633	533	164,181	633	1,266		2,318

2020 Budget	34,982
2020 Inventory	3,182
2020 Pension	12,881
2020 Return on Assets	48,864

SERVICE COMPANY COST ALLOCATION DETAILS
COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function	Allocation Method	Operating Unit	Alloc Pool
Facilities Rate of Return Allocation	Allocates the Service Company's portion of...	*Three Factor Formula*	DUKR	Facilities ROR Gvrnce

DPC 20056 Duke Power Governance	DEP 50991 DE Progress	DFF 50992 Progress Florida	DEO [illegible]	DED [illegible]	DED [illegible]	DEO	GEK [illegible]	DEK [illegible]	DEK	DEI 75950	Comm Pwr [illegible]	Comm	Comm Trans [illegible]	Gas Oper [illegible]	Peidmont 47151 Piedmont gas Ord	Other [illegible]	Other [illegible]	Other	[illegible]
35.41%	23.35%	15.93%	0.04%	3.24%	1.59%	4.87%	1.02%	0.35%	1.37%	10.51%	2.99%	2.99%	0.02%	0.02%	5.47%	0.02%	0.04%	0.06%	100.00%

Account #	Res Type	Resp Center	Revenue Requirement (provided by each	DPC	DEP	DFF	DEO	DED	DED	DEO	GEK	DEK	DEK	DEI	Comm Pwr	Comm	Comm Trans	Gas Oper	Piedmont	Other	Other	Other	Total
											6.48%												
				12	12	12	12	12	12		12	12		12	12		12	12	12	12	12		
				0.80%	0.72%	0.64%	0.76%	0.77%	0.76%		0.71%	0.77%		0.86%	0.80%		0.80%	0.80%	0.76%	0.80%	0.80%		
0931008 for expense	78000	8000 for expense																					
0456949 for income	78000	9857 for income		GO22	PCGS	PFGS	GO27	GO24	GO25		GO28	GO29		GO31	GO32		SG33	SG39	SG37	GO21	GO34		
		2020 Inventory value:	24,666,904	69,231	41,445	24,961	75	8,129	2,982		1,767	663		18,740	5,848		39	39	10,146	39	78		188,199
																				2020 Budget			2,162,385.66

SERVICE COMPANY COST ALLOCATION DETAILS
-COST ALLOCATIONS IN SERVICE AGREEMENTS

Function	Function	Allocation Method	Operating Unit	Alloc Pool	St Cd	DPC 20056 Duke Power Goverence	DEP 50991 DE Progress	PEF 50992 Progress Florida	DEO	DEO	DEO	DEK	DEK	DEK	DEI 75950	Comm Pwr	Piedmont	Other	Other	Total
Labor Allocation	Allocates the Service Company's services	*Labor Allocation*				29.50%	18.42%	11.95%	10.94%	4.13%	15.07%	3.11%	1.04%	4.15%	17.44%	1.60%	1.54%	0.32%	1.86%	100.00%
Account #	Res Type	Resp Center		Revenue Requirement (provided by each																
												8.46%								
						12	12	12	12	12		12	12		12	12	12	12		
						0.00%	0.00%	0.00%	0.00%	0.00%		0.71%	0.00%		0.00%	0.00%	0.00%	0.00%		
0931008 for expense	78000	8000 for expense																		
0456949 for income	78000	9957 for income				GO22	PCGS	PFGS	GO24	GO25		GO28	GO29		GO31	GO32	SG37	GO21		
		2020 Pension value:		**146,158,160**		343,113	194,566	111,491	123,121	46,077		32,046	11,717		165,260	18,611	16,994	3,764		**1,066,769**
																	2020 Budget			**12,801,104.02**

REQUEST:

Refer to the Company's CAM at page 13 that includes the following statement:

> By the terms of the Service Company Utility Service Agreement, compensation for any service rendered by the Service Company to its utility affiliates is the fully embedded cost thereof (i.e., the sum of: (i) direct costs; (ii) indirect costs; and (iii) costs of capital), except to the extent otherwise required by Section 482 of the Internal Revenue Code.

a. Describe how the "(iii) costs of capital" is determined by DEBS each period and provide that determination for each month applicable to 2018, 2019, and projected for the test year.

b. Describe the source of the return on equity percentage component utilized by DEBS for the "(iii) costs of capital" for each month applicable to 2018, 2019, and projected for the test year and cite all authorities, if any.

c. Indicate whether the "(iii) costs of capital" includes a gross up for income taxes.

RESPONSE:

a. The return on DEBS assets is based on a monthly calculation of DEBS assets. These assets include PP&E, prepaid pension assets and inventory. The PP&E is determined based on NET PP&E less CWIP less associated deferred taxes. Prepaid pension assets are determined by taking the prepaid qualified pension, less the non-qualified pension and OPEB liabilities and decreasing by a deferred tax amount. The inventory amount is the amount reflected on the inventory balance sheet for DEBS. The total allocated amount of assets assigned to the Regulated Utility is multiplied by a revenue requirement percentage to achieve the allowed rate of return in the jurisdiction. The amount allocated to the utility is based on a 3-factor allocation for PP&E and inventory assets. The pension assets are allocated based on DEBS labor usage. This process is applicable to 2018, 2019 and for the projected test year.

b. The source of the return on DEBS assets as it relates to the projected years in Kentucky is the revenue requirement based on the 2017 Kentucky Electric rate case. This is applicable for all actual and forecasted periods. See AG-DR-01-050(c) Attachment used in response to AG-DR-01-050(c).

c. Yes, the cost of capital is grossed up for income taxes.

PERSON RESPONSIBLE: Jeffrey R. Setser

EXHIBIT ____ (LK-21)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's Second Set Data Requests
Date Received: November 12, 2019

AG-DR-02-045

REQUEST:

Refer to the Direct Testimony of Mr. Setser ("Setser Direct"), at page 16, wherein he states, "Cost of capital represents financing costs, including, but not limited to, interest on debt and a fair return on equity to shareholders." Identify the source of this definition of cost of capital and provide a copy of the source document.

RESPONSE:

When analysts and investors discuss the cost of capital, they typically mean the weighted average of a firm's cost of debt and cost of equity blended together, which is used to finance the business.

The return on DEBS assets represents a proxy for recovering "cost of capital" (as referenced in the service agreements). Our interpretation of the cost of capital is the current allowed rate of return for the jurisdiction as if the assets were sitting on the jurisdiction's books. Any metrics involving DEBS are not applicable because they are not included in DEK's revenue requirement.

PERSON RESPONSIBLE: Jeff Setser

EXHIBIT ____ (LK-22)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-002

REQUEST:

Provide a trial balance for Duke Energy Business Services LLC ("DEBS") at December 31, 2016, December 31, 2017, December 31, 2018, and the most recent month for which the accounting books have been closed in 2019. In addition, provide a chart of accounts and subaccounts and the related descriptions that matches the accounts used in the trial balance.

RESPONSE:

Please see AG-DR-01-002 Attachment.

PERSON RESPONSIBLE: Danielle Weatherston

	Actuals 2016 Dec - December YTD - Year-to-Date 20013_LP.20013 - Duke Energy Business Services	Actuals 2017 Dec - December YTD - Year-to-Date 20013_LP.20013 - Duke Energy Business Services	Actuals 2018 Dec - December YTD - Year-to-Date 20013_LP.20013 - Duke Energy Business Services
0186480 - 0186480 - Misc Debits To Be Cleared	127,009.07	100,863.53	184,681.52
0186029 - 0186029 - Misc Def Debit MISO Activity	(0.18)	(0.18)	(0.18)
0186802 - 0186802 - Accr Pen FAS158 - Qual	49,270,755.52	47,229,260.52	35,182,580.52
0186889 - 0186889- Asset Recovery Deferred	244,556.88	644,549.57	820,811.17
0186984 - 0186984 - Other Long-Term Assets	4,665,000.00	4,665,000.00	4,665,000.00
0186104 - 0186104 - Deferred Asset-Exit Costs	10,125,249.19	7,991,593.27	5,857,937.35
0186171 - 0186171 -Reg Asset FAS 158 OCI NQ	11,305,989.00	11,689,739.00	9,644,051.00
0186295 - 0186295 - Deferred Storm Expenses	-	-	-
0186039 - 0186039 - East Bend CO2 Capture System	-	-	6,227.46
0186882 - 0186882 - Straight Line Lease Defer DR	-	-	-
0190001 - 0190001 - Adit: Prepaid: Federal Taxes	(225,116,810.50)	(196,358,444.87)	(126,274,519.77)
0190002 - 0190002 - Adit: Prepaid: State Taxes	(17,836,715.72)	(15,957,657.48)	(17,019,429.10)
0190051 - 0190051 - Accum Deferred FIT-OCI	(7,014,511.14)	(7,009,826.14)	(4,205,894.94)
0190052 - 0190052 - Accum Deferred SIT-OCI	(552,879.38)	(566,265.38)	(566,265.36)
0283020 - 0283020 - Valuation Allowance	(980,963.00)	(980,963.00)	(980,963.00)
0151150 - 0151150 - Jet Fuel	85,733.79	108,754.42	96,157.32
0201000 - 0201000 - Common Stock Issued	3.50	3.50	3.50
0211003 - 0211003 - Misc Paid in Capital	242,099,083.19	218,349,421.89	214,839,126.33
0208000 - 0208000 - Donations From Stockholder	47,200,000.00	47,200,000.00	47,200,000.00
0208010 - 0208010 - Donat Recvd From Stkhld Tax	(669,224.00)	(669,224.00)	(669,224.00)
0211004 - 0211004 - Misc Paid In Capital Purch Acctg	(180,602,490.08)	(180,602,490.08)	(180,602,490.08)
0211005 - 0211005 - Misc Paid In Capital Premerger Equity	(48,887,321.38)	(48,887,321.38)	(48,887,321.38)
0216000 - 0216000 - Unapprop Retained Earnings	(44,321,728.29)	(44,321,728.29)	(44,321,728.29)
F_RE_CHANGE - Current Month Net Income	26,921,299.22	28,827,848.50	36,104,623.44
0439300 - 0439300 - ADJUST TO R/E	-	-	-
0216100 - 0216100 - Unappr Undistr Subsid Earnings	439,329,489.67	466,196,790.43	516,749,656.62
0219020 - 0219020 - FAS 106 actuarial gain or loss	(0.00)	(0.00)	(0.00)
0219035 - 0219035 - OCI-Actuarial GL Qual	(1,579,538.97)	(1,579,538.97)	0.03
0219036 - 0219036 - OCI-Actuarial GL Qual Fed Tx	6,939,730.12	6,935,095.12	6,935,095.06
0219037 - 0219037 - OCI-Actuarial GL Qual St Tx	546,983.06	560,227.06	560,227.05
0219038 - 0219038 - OCI-Actuarial GL NQ	(507,764.07)	(507,764.07)	(507,764.07)
0219039 - 0219039 - OCI-Actuarial GL NQ Fed Tx	754,360.11	753,855.11	753,855.07
0219040 - 0219040 - OCI Actuarial GL NQ St Tx	59,459.11	60,899.11	60,899.11
0219041 - 0219041 - FAS 106 Actuarial GL Fed Tx	(679,580.09)	(679,126.09)	(679,126.19)
0219042 - 0219042 - FAS 106 Actuarial GL St Tx	(53,562.81)	(54,859.81)	(54,859.82)
0227103 - 0227103 - LT Cap Lease Oblig - Tax Oper	139,469,400.91	139,710,693.07	139,812,217.75
0227175 - 0227175 - LT Operating Lease Obligation	-	-	-
0227185 - 0227185 - LT Oper Lse Obligation Red Hat	-	-	-

	Actuals 2016 Dec - December YTD - Year-to-Date 20013_LP.20013 - Duke Energy Business Services	Actuals 2017 Dec - December YTD - Year-to-Date 20013_LP.20013 - Duke Energy Business Services	Actuals 2018 Dec - December YTD - Year-to-Date 20013_LP.20013 - Duke Energy Business Services
0253690 - 0253690 - Pension Deferred Credits	(0.00)	(0.00)	(0.00)
0253035 - 0253035 - Misc Def Cr - Genl Acctg	404,440.31	386,008.22	235,856.91
0253082 - 0253082 - OTH DEFER CR MISCELLANEOUS	3,294,721.51	3,126,733.19	2,929,555.96
0254689 - 0254689 - Reg Liability - OPEB	25,646,598.67	24,394,654.67	27,271,749.67
0282100 - 0282100 - Adit: PpandE: Federal Taxes	99,484,920.16	98,691,167.04	61,351,129.69
0282101 - 0282101 - Adit: PpandE: State Taxes	8,411,052.41	8,956,582.60	9,244,221.28
0283100 - 0283100 - Adit: Other: Federal Taxes	160,951,049.74	159,574,338.76	88,254,445.31
0283101 - 0283101 - Adit: Other: State Taxes	12,723,495.97	12,929,096.55	11,946,320.60
0207008 - 0207008 - Additional Paid In Capital	(2,437,390.76)	(2,437,390.76)	(2,437,390.76)
0219101 - 0219101 - OCI - FAS 87 actuarial gain or loss	(18,795,247.75)	(18,795,247.75)	(20,374,786.75)
0219103 - 0219103 - OCI - NQ 87 actuarial gain or loss	(1,707,006.75)	(1,707,006.75)	(1,707,006.75)
0219106 - 0219106 - OCI - FAS 106 actuarial gain or loss	1,995,221.50	1,995,221.50	1,995,221.50
0224696 - 0224696 - Other Longterm Liab	618,768.06	228,768.06	228,768.06
0232260 - 0232260 - Deposit Account	773,938.00	698,010.00	679,629.00
0454400 - 0454400 - Other Electric Rents	67,178.57	71,130.38	73,771.78
0456100 - 0456100 - Profit Or Loss on Sale of M&S	-	(49.52)	(22,181.86)
0456949 - 0456949 - Other Revenue Affiliate	48,110,962.00	45,533,007.56	51,511,543.38
0920000 - 0920000 - A and G Salaries	447,307,044.97	357,957,570.96	454,247,873.66
0921100 - 0921100 - Employee Expenses	18,735,474.06	18,454,762.77	21,771,950.84
0921200 - 0921200 - Office Expenses	49,980,719.50	53,674,509.74	54,680,594.49
0921300 - 0921300 - Telephone and Telegraph Exp	27,227.79	21,973.78	17,604.33
0921400 - 0921400 - Computer Services Expenses	42,631,596.76	42,183,224.98	41,319,310.29
0921540 - 0921540 - Computer Rent (Go Only)	33,268,063.32	33,940,267.38	45,304,721.28
0921600 - 0921600 - Other	(18,843.66)	51,461.51	73,452.53
0921980 - 0921980 - Office Supplies and Expenses	195,366,573.87	436,268,858.69	396,329,193.03
0922000 - 0922000 - Admin Exp Transfer	195,560.98	119,704.66	83,443.19
0923000 - 0923000 - Outside Services Employed	168,561,999.90	197,893,334.93	189,988,702.40
0923980 - 0923980 - Outside Services Employee and	1,807,330.71	2,437,322.68	3,422,593.58
0924000 - 0924000 - Property Insurance	253,879.85	140,967.49	143,100.69
0924050 - 0924050 - Intercompany Property Insurance Exp	447,000.00	469,700.04	273,600.00
0924980 - 0924980 - Property Insurance For Corp.	16,089,696.00	15,790,115.04	15,050,382.96
0925200 - 0925200 - Injuries and Damages - Other	953,834.89	689,695.11	710,827.98
0925980 - 0925980 - Injuries and Damages For Corp.	1,218,000.00	1,227,600.00	1,243,000.08
0926000 - 0926000 - Employee Benefits	183,084,058.16	179,012,201.02	216,003,638.20
0926420 - 0926420 - Employees' Tuition Refund	-	3,126.04	2,280.71
0926600 - 0926600 - Employee Benefits - Transferred	589,384,645.29	622,239,092.17	581,693,987.12
0930200 - 0930200 - Misc General Expenses	(164,451,407.46)	(151,869,347.80)	(162,440,022.57)
0930210 - 0930210 - Industry Association Dues	3,192,258.38	3,185,969.88	3,165,248.00

EXHIBIT ____ (LK-23)

AG-DR-01-019

REQUEST:

Describe how DEBS treated the EDIT resulting from the lower federal income tax rate due to the TCJA. Provide the DEBS accounting entries.

RESPONSE:

DEBS remeasured its ADIT based on the new federal corporate income tax rate of 21% and removed the excess ADIT through the income statement.

BU 20011: Duke Energy Corporate Services, Inc.
BU 20013: Duke Energy Business Services, LLC

BU	Account	Amount
20011	0282100	(1,400,278)
20011	0410240	1,400,835
20011	0411240	(557)
20013	0190001	(78,967,868)
20013	0282100	39,476,466
20013	0283100	64,020,350
20013	0410240	157,689,441
20013	0411240	(182,218,390)
20013	0190051	(2,803,931)
20013	0410240	2,803,931

PERSON RESPONSIBLE: John Panizza

EXHIBIT ____ (LK-24)

AG-DR-01-018

REQUEST:

Provide a schedule showing the EDIT by temporary difference for DEBS (total DEBS and allocation to DEK-Electric Division) due to the remeasurement of ADIT resulting from the lower federal income tax rate due to the TCJA. If there was no allocation to DEK, then provide the DEBS allocation factor used to allocate/charge depreciation expense on DEBS assets to DEK-Electric Division.

RESPONSE:

There was not an allocation of DEBS EDIT to DEK – Electric Division. The DEBS allocation factor used to allocate/charge depreciation expense on DEBS' asset to DEK-Electric Division is 0.74%.

PERSON RESPONSIBLE: John Panizza

EXHIBIT ____ (LK-25)

AG-DR-01-033

REQUEST:

Provide a schedule and electronic spreadsheet in live format with all formulas intact showing the additional depreciation expense in the test year for each account and in total due to the proposed change in depreciation rates. In addition, on this same schedule, provide the related increase in accumulated depreciation and reduction in ADIT.

RESPONSE:

Please see AG-DR-01-033 Attachment.

PERSON RESPONSIBLE: Christopher Jacobi, as to adt'l depreciation expense
John Panizza, as to ADIT impact
Melissa Abernathy, as to depreciation rates

DEPRECIATION AND AMORTIZATION ACCRUAL RATES AND
JURISDICTIONAL ACCUMULATED BALANCES BY ACCOUNTS,
FUNCTIONAL CLASS OR MAJOR PROPERTY GROUP
THIRTEEN MONTH AVERAGE AS OF MARCH 31, 2021

STEAM PRODUCTION PLANT

WORK PAPER REFERENCE NOS.: SCHEDULE B-3.2

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	Current Accrual Rate (H)	Calculated Depr/Amort Expense (I=DxH)	Difference Actual vs Proposed (J=G-I)	Effective Tax Rate (K)	ADIT Impact (L=J*K)
				$	$		$		$			
1	310	3100	Land and Land Rights	7,077,698	91,195	0.00%	0	0.00%	0	0	24.925%	0
2	311	3110	Structures & Improvements	79,405,814	38,017,956	3.63%	2,882,431	2.47%	1,961,324	921,107	24.925%	229,588
3	312	3120	Boiler Plant Equipment	490,994,318	280,138,134	2.89%	14,189,736	2.24%	10,998,273	3,191,463	24.925%	795,472
4	312	3123	Boiler Plant Equip - SCR Catalyst	7,579,713	5,905,617	0.60%	45,478	4.56%	345,635	(300,157)	24.925%	(74,814)
5	314	3140	Turbogenerator Equipment	104,333,182	57,698,417	2.82%	2,942,198	2.36%	2,462,263	479,933	24.925%	119,623
6	315	3150	Accessory Electric Equipment	49,163,779	32,433,295	2.15%	1,057,451	2.24%	1,101,717	(44,266)	24.925%	(11,033)
7	316	3160	Miscellaneous Powerplant Equipment	21,421,006	10,749,774	3.37%	721,888	3.17%	679,046	42,842	24.925%	10,678
8	317	3170	AROs	0	0	Various		Various		0	24.925%	0
9			Case 2015-120 Acq of DPL Share of East Bend	10,321,540	0	-	490,618	-	490,618	0	24.925%	0
10			Completed Construction Not Classified	65,023,502	2,086,782	2.95%	1,918,193	2.33%	1,515,048	403,145	24.925%	100,484
11		108	Retirement Work in Progress	0	(25,960,866)		0		0	0	24.925%	0
12			Total Steam Production Plant	835,340,554	401,160,304		24,247,991		19,553,924	4,694,067		1,169,996

(1) Plant Investment Includes Completed Construction Not Classified (Account 106).

OTHER PRODUCTION PLANT

WORK PAPER REFERENCE NOS.: SCHEDULE B-3.2

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	Current Accrual Rate (H)	Calculated Depr/Amort Expense (I=DxH)	Difference Actual vs Proposed (J=G-I)	Effective Tax Rate (K)	ADIT Impact (L=J*K)
				$	$		$					
1	340	3400	Land and Land Rights	3,035,569	0	0.00%	0	0.00%	0	0	24.925%	0
2	340	3401	Rights of Way	651,684	362,052	3.21%	20,919	3.77%	24,568	(3,649)	24.925%	(910)
3	341	3410	Structures & Improvements	36,434,298	26,827,441	2.69%	980,083	2.52%	918,144	61,939	24.925%	15,438
4	342	3420	Fuel Holders, Producers, Accessories	61,957,346	10,614,748	2.39%	1,480,781	2.13%	1,319,691	161,090	24.925%	40,152
5	343	3430	Prime Movers	1,478,010	64,275	3.94%	58,234	3.36%	49,661	8,573	24.925%	2,137
6	344	3440	Generators	212,680,828	129,112,533	3.94%	8,379,625	3.36%	7,146,076	1,233,549	24.925%	307,462
7	344	3446	Solar Generators - Crittenden	4,168,276	524,319	4.85%	202,161	4.72%	196,743	5,418	24.925%	1,350
8	344	3446	Solar Generators - Walton	5,747,433	727,532	4.85%	278,751	4.72%	271,279	7,472	24.925%	1,862
9	345	3450	Accessory Electric Equipment	21,458,194	12,717,821	4.18%	896,953	3.82%	819,703	77,250	24.925%	19,255
10	345	3456	Solar Accessory Electric Equipment - Crittenden	425,603	49,965	5.62%	23,919	4.44%	18,897	5,022	24.925%	1,252
11	345	3456	Solar Accessory Electric Equipment - Walton	631,334	74,856	5.61%	35,418	4.44%	28,031	7,387	24.925%	1,841
12	346	3460	Miscellaneous Plant Equipment	4,823,553	3,154,798	3.73%	179,919	3.71%	178,954	965	24.925%	241
13			Completed Construction Not Classified	19,959,856	2,700,831	3.76%	750,491	3.23%	644,703	105,788	24.925%	26,368
14		108	Retirement Work In Progress	0	(2,709,383)							
15			Total Other Production Plant	373,451,984	184,221,788		13,287,254		11,616,450	1,670,804		416,448

(1) Plant Investment Includes Completed Construction Not Classified (Account 106).

TRANSMISSION PLANT

WORK PAPER REFERENCE NOS.: SCHEDULE B-3.2

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average: Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average: Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	Current Accrual Rate (H)	Calculated Depr/Amort Expense (I=DxH)	Difference Actual vs Proposed (J=G-I)	Effective Tax Rate (K)	ADIT Impact (L=J*K)
				$	$		$					
1	350	3500	Land	308,628	0	0.00%	0	0.00%	0	0	24.925%	0
2	350	3501	Rights of Way	1,029,093	695,812	0.99%	10,188	1.27%	13,069	(2,881)	24.925%	(718)
3	352	3520	Structures & Improvements	1,480,413	315,945	2.00%	29,608	1.96%	29,016	592	24.925%	148
4	353	3530	Station Equipment	18,106,965	5,146,842	2.22%	401,975	2.16%	391,111	10,864	24.925%	2,708
5	353	3531	Station Equipment - Step Up	9,446,665	4,490,892	2.05%	193,657	2.05%	193,657	0	24.925%	0
6	353	3532	Station Equipment - Major	5,826,370	2,146,937	1.50%	87,396	1.73%	100,796	(13,400)	24.925%	(3,340)
7	353	3534	Station Equipment - Step Up Equipment	7,057,290	1,664,980	3.31%	233,596	4.13%	291,466	(57,870)	24.925%	(14,424)
8	355	3550	Poles & Fixtures	11,047,254	3,937,714	1.76%	194,432	1.76%	194,432	0	24.925%	0
9	356	3560	Overhead Conductors & Devices	6,214,443	3,888,799	1.26%	78,302	1.91%	118,696	(40,394)	24.925%	(10,068)
10	356	3561	Overhead Conductors - Clear R/W	744,846	35,380	1.69%	12,588	1.74%	12,960	(372)	24.925%	(93)
11			Completed Construction Not Classified	11,109,715	197,982	2.05%	227,749	2.24%	248,858	(21,109)	24.925%	(5,261)
12		108	Retirement Work In Progress	0	(2,582,258)		0	0.00%	0	0	24.925%	0
13			Total Transmission Plant	72,371,702	19,959,025		1,469,491		1,594,061	(124,570)		(31,049)

(1) Plant Investment includes Completed Construction Not Classified (Account 106).

DISTRIBUTION PLANT

WORK PAPER REFERENCE NOS.: SCHEDULE B-3.2

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average Plant Investment (1) (D)	Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	Current Accrual Rate (H)	Calculated Depr/Amort Expense (I=DxH)	Difference Actual vs Proposed (J=G-I)	Effective Tax Rate (K)	ADIT Impact (L=J*K)
				$	$		$					
1	360	3600	Land and Land Rights	7,236,361	0	0.00%	0	0.00%	0	0	24.925%	0
2	360	3601	Rights of Way	4,483,802	3,125,286	0.81%	36,319	1.03%	46,183	(9,864)	24.925%	(2,459)
3	361	3610	Structures & Improvements	1,393,417	61,929	2.08%	28,983	2 26%	31,491	(2,508)	24.925%	(625)
4	362	3620	Station Equipment	43,986,026	5,055,285	3.10%	1,363,567	2.35%	1,033,672	329,895	24.925%	82,226
5	362	3622	Station Equipment - Major	31,367,795	10,241,335	1.42%	445,423	1.59%	498,748	(53,325)	24.925%	(13,291)
6	363	3630	Storage Battery Equipment	2,508,971	0	6.78%	170,108	6.78%	170,108	0	24.925%	0
7	364	3640	Poles, Towers & Fixtures	64,155,514	29,353,871	2.04%	1,308,772	2.09%	1,340,850	(32,078)	24.925%	(7,995)
8	365	3650	Overhead Conductors & Devices	123,949,869	38,121,959	2.42%	2,999,587	2.14%	2,652,527	347,060	24.925%	86,505
9	365	3651	Overhead Conductors - Clear R/W	5,134,079	369,333	1.64%	84,199	1.65%	84,712	(513)	24.925%	(128)
10	366	3660	Underground Conduit	25,165,008	7,526,661	1.60%	402,640	1.80%	452,970	(50,330)	24.925%	(12,545)
11	367	3670	Underground Conductors & Devices	63,480,020	18,694,106	2.55%	1,618,741	2.07%	1,314,036	304,705	24.925%	75,948
12	368	3680	Line Transformers	62,153,454	26,690,275	1.90%	1,180,916	1.68%	1,044,178	136,738	24.925%	34,082
13	368	3682	Customers Transformer Installation	273,661	279,620	0.49%	1,341	0.31%	848	493	24.925%	123
14	369	3691	Services - Underground	2,458,590	647,159	1.70%	41,796	1.87%	45,976	(4,180)	24.925%	(1,042)
15	369	3692	Services - Overhead	18,767,918	11,012,232	1.52%	285,272	1.21%	227,092	58,180	24.925%	14,501
16	370	3700	Meters	2,752,936	1,253,617	3.46%	95,252	6.32%	173,986	(78,734)	24.925%	(19,624)
17	370	3702	AMI Meters	19,820,983	3.712,188	6.86%	1,359,719	6.85%	1,357,737	1,982	24.925%	494
18	371	3711, 3712	Company Owned Outdoor Lighting	(132,525)	(569,147)	17.90%	(23,722)	5.26%	(6,971)	(16,751)	24.925%	(4,175)
19	372	3720	Leased Property on Customers	9,647	9,647	N/A (2)	N/A (2)	NA (2)	N/A (2)	N/A	24.925%	N/A
20	373	3731	Street Lighting - Overhead	2,363,379	2,032,447	1.16%	27,415	0.73%	17,253	10,162	24.925%	2,533
21	373	3732	Street Lighting - Boulevard	3,355,356	2.600,547	1.21%	40,600	1.18%	39,593	1,007	24.925%	251
22	373	3733	Street Lighting - Cust, Private Outdoor Lighting	0	0	2.56%	0	2.67%	0	0	24.925%	0
23	373	3734	Light Choice OLE	0	0	2.56%	0	2.67%	0	0	24.925%	0
24			Completed Construction Not Classified	94,687,831	1,525,727	2.43%	2,300,914	2.11%	1,997,913	303,001	24.925%	75,523
25		108	Retirement Work In Progress	0	(17,119,217)		0	0.00%	0	0	24.925%	0
											24.925%	
26			Total Distribution Plant	579,372,092	144,824,660		13,767,842		12,522,902	1,244,940		310,301

(1) Plant Investment includes Completed Construction Not Classified (Account 106).
(2) This account is fully depreciated.

GENERAL PLANT

WORK PAPER REFERENCE NOS.: SCHEDULE B-3.2

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average: Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average: Accumulated Balance (E)	Proposed Accrual Rate (F)	Calculated Depr/Amort Expense (G=DxF)	Current Accrual Rate (H)	Calculated Depr/Amort Expense (I=DxH)	Difference Actual vs Proposed (J=G-I)	Effective Tax Rate (K)	ADIT Impact (L=J*K)
				$	$		$					
1	303	3030	Miscellaneous Intangible Plant	21,563,744	12,133,239	Various	2,224,721	Various	2,224,721	0	24.925%	0
2	390	3900	Structures & Improvements	144,984	59,062	2.82%	4,089	3.40%	4,929	(840)	24.925%	(209)
3	391	3910	Office Furniture & Equipment	25,630	20,710	5.00%	1,282	5.00%	1,282	0	24.925%	0
4	391	3910-URR	Office Furniture & Equipment		8,721	NA	(2) (1,744) (2)	NA	(2) (251) (2)	(1,493)	24.925%	(372)
5	391	3911	Electronic Data Proc Equip	2,370,456	1,331,560	20.00%	474,091	20.00%	474,091	0	24.925%	0
6	391	3911-URR	Electronic Data Proc Equip		81,900	NA	(2) (16,380) (2)	NA	(2) (48,400) (2)	32,020	24.925%	7,981
7	392	3920	Transportation Equipment	647,346	48,163	8.54%	Transp Expense	8.56%	Transp Expense	Transp Expense	24.925%	Transp Expense
8	392	3921	Trailers	254,440	156,493	3.57%	Transp Expense	3.84%	Transp Expense	Transp Expense	24.925%	Transp Expense
9	394	3940	Tools, Shop & Garage Equipment	2,573,399	805,637	4.00%	102,936	4.00%	102,936	0	24.925%	0
10	394	3940-URR	Tools, Shop & Garage Equipment		(40,000)	NA	(2) 8,000 (2)	NA	(2) 8,600 (2)	(600)	24.925%	(150)
11	396	3960	Power Operated Equipment	11,770	7,029	6.00%	Transp Expense	6.74%	Transp Expense	Transp Expense	24.925%	Transp Expense
12	397	3970	Communication Equipment	4,329,278	1,992,633	6.67%	288,763	6.67%	288,763	0	24.925%	0
13	397-URR	3970	Communication Equipment		28,711	NA	(2) (5,942) (2)	NA	(2) (15,000) (2)	9,058	24.925%	2,258
14			Completed Construction Not Classified	24,799,586	1,622,460	9.31%	2,308,841	9.90%	2,455,159	(146,318)	24.925%	(36,470)
15		108	Retirement Work In Progress	0	21,532							
16			Total General Plant	56,720,633	18,278,850		5,388,657		5,496,830	(108,173)		(26,962)
17			Total Electric Plant	1,917,256,965	768,444,827		58,161,235		50,784,167	7,377,068		1,838,734

(1) Plant Investment includes Completed Construction Not Classified (Account 106).
(2) 5 year life for Unrecovered Reserve for Amortization

COMMON PLANT

WORK PAPER REFERENCE NOS.: SCHEDULE B-3.2

Line No. (A)	FERC Acct. No. (B-1)	Company Acct. No. (B-2)	Account Title or Major Property Grouping (C)	Adjusted Jurisdiction 13-Month Average: Plant Investment (1) (D)	Adjusted Jurisdiction 13-Month Average: Accumulated Balance (E)	Proposed Accrual Rate (F)		Calculated Depr/Amort Expense (G=DxF)	Current Accrual Rate (H)		Calculated Depr/Amort Expense (I=DxH)	Difference Actual vs Proposed (J=G-I)	Effective Tax Rate (K)	ADIT Impact (L=J*K)
				$	$			$						
1		1030	Miscellaneous Intangible Plant	22,332,073	22,332,073	Various	(4)	0 (4)	Various	(4)	0	0	24.925%	0
2		1890	Land and Land Rights	1,041,678	0	0.00%		0	0.00%		0	0	24.925%	0
3		1900	Structures & Improvements	11,594,044	1,708,855	1.59%	(2)	184,345 (2)	1.26%	(2)	146,085 (2)	38,260	24.925%	9,536
4		1910	Office Furniture & Equipment	397,455	195,441	5.00%		19,873	5.00%		19,873	0	24.925%	0
5		1910-URR	Office Furniture & Equipment		61,000	NA	(3)	(12,200) (3)	NA	(3)	(110) (3)	(12,090)	24.925%	(3,013)
6		1911	Office Furniture & Equipment - EDP Equipment	40,535	(333,849)	20.00%		8,107	20.00%		8,107	0	24.925%	0
7		1911-URR	Office Furniture & Equipment - EDP Equipment		(31,041)	NA	(3)	6,208 (3)	NA	(3)	11,520 (3)	(5,312)	24.925%	(1,324)
8		1940	Tools, Shop & Garage Equipment	105,587	49,340	4.00%		4,223	4.00%		4,223	0	24.925%	0
9		1940-URR	Tools, Shop & Garage Equipment		22,400	NA	(3)	(4,480) (3)	NA	(3)	(3,600) (3)	(880)	24.925%	(219)
10		1970	Communication Equipment	8,088,865	6,060,116	6.67%		539,527	6.67%		539,527	0	24.925%	0
11		1970-URR	Communication Equipment		3,497,100	NA	(3)	(699,420) (3)	NA	(3)	(753,200) (3)	53,780	24.925%	13,405
12		1980	Miscellaneous Equipment	41,504	26,441	6.67%		2,768	6.67%		2,768	0	24.925%	0
13		1980-URR	Miscellaneous Equipment		(3,750)	NA	(3)	750 (3)	NA	(3)	860 (3)	(110)	24.925%	(27)
14		1990	ARO - Common Plant		0	Various			0.00%		0	0	24.925%	0
15			Completed Construction Not Classified		0	3.30%		0	4.13%		0	0	24.925%	0
16		108	Retirement Work In Progress		(8,800)									
17			Total Common Plant	43,641,741	33,575,326			49,701			(23,947)	73,648		18,357
			Common Plant Allocated to Electric											
18		73.56%	Original Cost	32,102,866										
19		73.56%	Reserve		24,698,010									
20		73.56%	Annual Provision					36,560			(17,615)	54,175		
21			Total Electric Plant Including Allocated Common	1,949,359,831	793,142,837			58,197,795			50,766,552	7,431,243		1,838,734

(1) Plant Investment includes Completed Construction Not Classified (Account 106).
(2) Composite of four groups in Structures & Improvements account.
(3) 5 year life for Unrecovered Reserve for Amortization
(4) Fully Amortized

EXHIBIT ____ (LK-26)

Duke Energy Kentucky
Case No. 2019-00271
Attorney General's First Set Data Requests
Date Received: October 14, 2019

AG-DR-01-023

REQUEST:

Provide an electronic copy, with all formulas intact, of all schedules and supporting workpapers used in the depreciation study presented in the Direct Testimony of John J. Spanos ("Spanos Direct") including but not limited to Attachment JJS-1, Table 1 at pages VI-4 through VI-6 and pages VIII-2 through VIII-4.

RESPONSE:

Attached are electronic versions of the workpapers, including data files and schedules, used for the depreciation study.

AG-DR-01-023 Attachment 1 - Service Life Data.xlsx
AG-DR-01-023 Attachment 2 - Net Salvage Data.xlsx
AG-DR-01-023 Attachment 3 - Table1.xlsx
AG-DR-01-023 Attachment 4 - Life Analysis.docx
AG-DR-01-023 Attachment 5 - Net Salvage Analysis.docx
AG-DR-01-023 Attachment 6 - Terminal Net Salvage.xlsx
AG-DR-01-023 Attachment 7 - Depreciation Calculations.docx

PERSON RESPONSIBLE: John J. Spanos

DUKE ENERGY KENTUCKY

TABLE 1. CALCULATION OF TERMINAL AND INTERIM RETIREMENTS AS A PERCENT OF TOTAL RETIREMENT!

LOCATION	PROJECTED RETIREMENTS TERMINAL	INTERIM	TOTAL OF ALL RETIREMENTS	TERMINAL RETIREMENT %	INTERIM RETIREMENT %
(1)	(2)	(3)	(4)=(2)+(3)	(5)=(2)/(4)	(6)=(3)/(4)
STEAM PRODUCTION					
EAST BEND	(586,841,127)	(224,028,578)	(810,869,705)	72.37	27.63
OTHER PRODUCTION					
WOODSDALE	(241,286,089)	(54,316,593)	(295,602,682)	81.63	18.37

DUKE ENERGY KENTUCKY

TABLE 2. CALCULATION OF WEIGHTED NET SALVAGE PERCENT

	TERMINAL RETIREMENTS		INTERIM RETIREMENTS		
LOCATION	RETIREMENTS (%)	NET SALVAGE (%)	RETIREMENTS (%)	NET SALVAGE (%)	WEIGHTED AVERAGE NET SALVAGE %
(1)	(2)	(3)	(4)	(5)	(6)=(2)*(3)+(4)*(5)
STEAM PRODUCTION					
EAST BEND	72.37	(13)	27.63	(20)	(15)
OTHER PRODUCTION					
WOODSDALE	81.63	(4)	18.37	(6)	(5)

DUKE ENERGY KENTUCKY

TABLE 3. CALCULATION OF TERMINAL NET SALVAGE PERCENT

UNIT	ESTIMATED RETIREMENT YEAR	MW	TOTAL DECOMMISSIONING COSTS (CURRENT $)	TOTAL DECOMMISSIONING COSTS (FUTURE $)	ESTIMATED TERMINAL RETIREMENTS	TERMINAL NET SALVAGE (%)
(1)	(2)	(3)	(4)	(5)	(6)	(7)=(5)/(6)
STEAM PRODUCTION						
EAST BEND	2041	772	34,334,000	60,586,143	(586,841,127)	(13)
MIAMI FORT UNIT 6				12,996,986		
OTHER PRODUCTION						
WOODSDALE	2032	564	6,267,000	8,855,107	(241,286,089)	(4)

EXHIBIT ____ (LK-27)

Duke Energy Kentucky
Case No. 2019-00271
Staff's Second Set Data Requests
Date Received: October 11, 2019

STAFF-DR-02-146

REQUEST:

Refer to the Spanos Testimony, page 11, lines 22-23. Provide a copy of the Burns and McDonnell decommissioning studies for the East Bend Generating Station and the Woodsdale Generating Station.

RESPONSE:

Please see STAFF-DR-02-146 for the Burns and McDonnell decommissioning study, which is the same study provided in the last rate case.

PERSON RESPONSIBLE: John J. Spanos

BURNS McDONNELL

Decommissioning Cost Estimate Study

DUKE ENERGY.

Duke Energy Kentucky

Decommissioning Cost Estimate Study
Project No. 95525

3/22/2017

Decommissioning Cost Estimate Study

prepared for

Duke Energy Kentucky
Decommissioning Cost Estimate Study
Union, Kentucky

Project No. 95525

3/22/2017

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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EXECUTIVE SUMMARY

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LIST OF ABBREVIATIONS

Abbreviation	**Term/Phrase/Name**
Burns & McDonnell	Burns & McDonnell Engineering Company, Inc.
BOP	Balance of Plant Facilities
C&D	Construction and Demolition
CT	Combustion Turbine
DEK	Duke Energy Kentucky
OSHA	Occupational Safety and Health Administration
PCBs	Polychlorinated Biphenyls
Plants	Power Generation Assets
RS Means	Construction Cost Estimating Data
STG	Steam Turbine Generator
Study	Decommissioning Cost Study

1.0 EXECUTIVE SUMMARY

1.1 Introduction

Burns & McDonnell Engineering Company, Inc. ("Burns & McDonnell") of Kansas City, Missouri, was retained by Duke Energy Kentucky ("DEK") to conduct a Decommissioning Cost Study ("Study") for power generation assets ("Plants") in Kentucky and Ohio. The assets include natural gas and coal-fired 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 Burns & McDonnell using information provided by DEK and in-house data available to Burns & McDonnell.

1.2 Results

Burns & McDonnell has prepared cost estimates in 2016 dollars for the decommissioning of the Plants. These cost estimates are summarized in Table 1-1. 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 steel.

Table 1-1: Decommissioning Cost Estimate Summary (2016$)

Plant	Decommissioning Costs	Credits	Net Project Cost
Woodsdale Station	$ 10,067,000	$ (3,800,000)	$ 6,267,000
Miami Fort Station Unit 6 – Retire in Place [1]	$ 13,046,000	$ (257,000)	$ 12,789,000
Miami Fort Station Unit 6– Full Demolition [2]	$ 5,754,000	$ (1,903,000)	$ 3,851,000
East Bend Station	$ 42,321,000	$ (7,987,000)	$ 34,334,000

Notes:
[1]: Retire in Place costs are assumed to be incurred in the near term to reduce environmental liabilities and risks associated with a non-operating unit.
[2]: The Full Demotion costs are in addition to the Retire in Place costs and are assumed to take place after the retirement of all of the currently operating units owned by Dynegy.

The total net project costs presented above include the costs to return the sites to an industrial condition suitable for reuse for development of an industrial facility. Included are the costs to dismantle the power generating equipment owned by DEK as well as the costs to dismantle the DEK-owned balance of plant facilities ("BOP") and environmental site restoration activities.

DEK does not own all assets at Miami Fort Station and only those assets associated with Unit 6 are considered in this Study.

1.3 Statement of Limitations

In preparation of this decommissioning study, Burns & McDonnell has relied upon information provided by DEK. Burns & McDonnell acknowledges that it has requested the information from DEK that it deemed necessary to complete this study. While Burns & McDonnell has no reason to believe that the information provided, and upon which Burns & McDonnell has relied, is inaccurate or incomplete in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness.

Burns & McDonnell's estimates and projections of decommissioning costs are based on Burns & McDonnell's experience, qualifications and judgment. Since Burns & McDonnell has no control over weather, cost and availability of labor, material and equipment, labor productivity, construction contractors' procedures and methods, and other factors, Burns & McDonnell does not guarantee the accuracy of its estimates and projections.

Burns & McDonnell's estimates do not include allowances for unforeseen environmental liabilities associated with unexpected environmental contamination due to events not considered part of normal operations, such as fuel tank ruptures, oil spills, etc. Estimates also do not include allowances for environmental remediation associated with changes in classification of hazardous materials.

2.0 INTRODUCTION

2.1 Background

Burns & McDonnell was retained by DEK to conduct a study for Plants in Kentucky and Ohio to estimate the decommissioning costs. The assets include natural gas and coal-fired generating facilities. Individuals from Burns & McDonnell visited each of the Plants covered by the Study in January of 2017. 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.

Burns & McDonnell has prepared decommissioning studies for over 100 facilities on various types of fossil fuel and renewables power plants using a proven approach to developing these estimates. In addition to preparing decommissioning estimates, Burns & McDonnell has supported demolition projects as the owner's engineer, to evaluate demolition bids and oversee demolition activities. This has provided Burns & McDonnell with insight into the range of competitive demolition bids, which also assists in confirming the reasonableness of the decommissioning estimates developed by Burns & McDonnell.

2.2 Study Methodology

The site decommissioning costs were developed using information provided by DEK and in-house data Burns & McDonnell has collected from previous project experience. Burns & McDonnell estimated quantities for equipment based on a visual inspection of the facilities, review of engineering drawings, Burns & McDonnell's in-house database of plant equipment quantities, and Burns & McDonnell'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. 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 for each site.

The decommissioning costs include the cost to return the site to an industrial condition, suitable for reuse for development of an industrial facility, commonly referred to as a brownfield site. Included are the costs to decommission all of the assets owned by DEK at the site, including power generating equipment and BOP facilities.

2.3 Site Visits

Representatives from Burns & McDonnell and DEK visited the sites. The site visits consisted of a tour of each facility with plant personnel to review the equipment installed at each site. Tours were conducted by plant personnel.

Mr. John Edelen, from Duke Energy Kentucky, served as the DEK representative throughout the site visits, along with plant personnel at each of the sites.

The following Burns & McDonnell representatives comprised the site visit team:

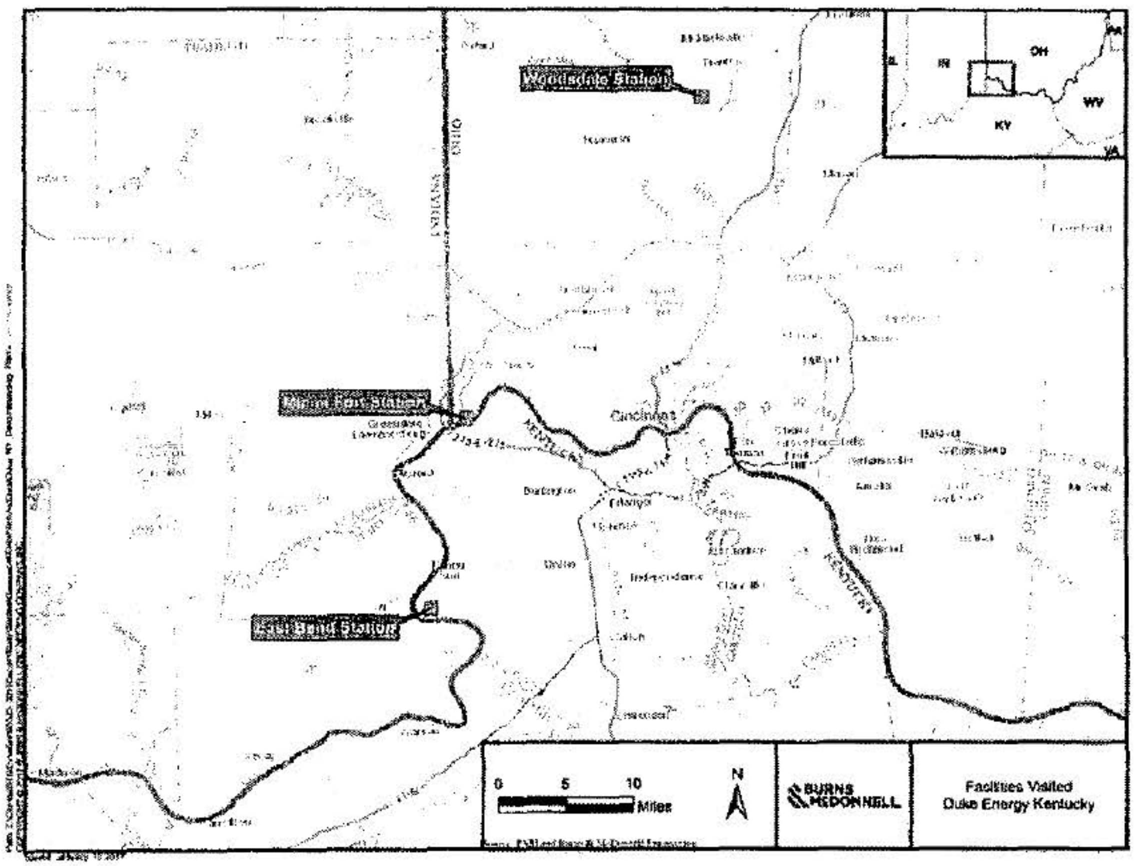
- Mr. Jeff Kopp, Project Manager
- Mr. Thom Bristow, Project Engineer
- Ms. Sara Ruckman, Lead Consultant

The site visits were performed on the following dates.

Table 2-1: Site Visit Dates

Plant	Site Visit Date
Woodsdale	December 12, 2016
Miami Fort	December 13, 2016
East Bend	December 13, 2016

Figure 2-1: DEK Facilities Visited



3.0 PLANT DESCRIPTIONS

The following sections provide site descriptions for each of the power 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 combustion turbines 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.

3.2 Coal Generation

3.2.1 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 & 2 retired in 1971 and were replaced by Unit 8. Units 3 & 4 retired in 1981, and Unit 5 retired on December 31, 2007. Only two units remain in operation (Units 7 & 8). Units 6, owned by DEK, has a nameplate capacity of 163 MW.

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.

3.2.2 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 and the concrete for a control center building were built for Unit 1. These assets were left on site and have not been removed.

4.0 DECOMMISSIONING COSTS

Burns & McDonnell 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 sufficient scrap value to a scrap contractor to offset a portion of the site decommissioning costs. However, DEK will incur costs of decommissioning of the Plants and restoration of the site to the extent that those costs exceed the scrap value of equipment and bulk steel.

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 dismantle all of the assets owned by DEK at the sites, including power generating equipment and BOP facilities, as well as environmental site restoration activities.

For purposes of this Study, Burns & McDonnell has assumed that each site will be decommissioned as a single project allowing the most cost effective demolition methods to be utilized. However, due to the current operation of Unit 7 and Unit 8 owned by Dynegy at Miami Fort, two (2) decommissioning cost estimates have been developed for that facility. The first summary provides cost estimates to retire in place the equipment and facilities for Unit 6. This includes performing tasks to reduce environmental and safety risks until full demolition occurs in the future. The retire in place cost summary also includes the removal of both Unit 6 precipitators to mitigate safety risks and to eliminate the need for maintenance of the retired assets in the future. The second cost estimate summary for Miami Fort included the costs associated with decommissioning and demolishing the entire plant as a single project. In this cost estimate, DEK is only responsible for costs associated with the Unit 6 assets that they own. Duke will be responsible for both the retire in place costs and full demolition of Unit 6, but the costs will be incurred at different times.

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 Burns & McDonnell. It will be the contractor's responsibility to determine means and methods that result in safely decommissioning 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 vandalism, to increase cash flow, and for separation of recyclable materials, in order 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, combustion turbines ("CT"), steam turbine generators ("STG"), 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 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 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.

For the retire in place estimate, the Miami Fort Unit 6 precipitators would likely be demolished utilizing a crane for removal from the top of the building, then cutting them into manageable sized pieces on the ground, since it cannot be felled, due to the continued operation of the remaining units.

4.1 General Assumptions for All Sites

The following assumptions were made as the basis of all of the cost estimates.

1. All cost estimates are in current 2016 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 with the exception of the retire in place cost estimate.
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. Any costs necessary to support on-going operations of adjacent or newly proposed units will be allocated to the operating costs of the units not being decommissioned.
14. 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.
15. Any residual oil or sludge in tanks and pipes will be cleaned up by DEK prior to demolition.

16. 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.
17. All scrap materials include a deduction for transportation and are based on pricing at the Cincinnati hub and, with the exception of stainless steel, which is based on the Cleveland hub.
18. All scrap will be transported by truck rather than by train due to the high costs associated with shipping by train for this short of a distance.
19. It is assumed that sufficient area to receive, assemble and temporarily store equipment and materials is available.
20. Step-up transformers, auxiliary transformers, and spare transformers are included for demolition and scrap in all estimates.
21. 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.
22. 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.
23. 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.
24. 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.
25. All pipe supports, and pipe racks will be demolished and scrapped.
26. Three feet of soil beneath the fuel oil tanks is to be removed and replaced with clean fill.
27. 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.
28. All portable tanks will be removed from the site and scrapped, including any propane tanks, oil storage tanks, and waste oil tanks.
29. All production wells will be closed as per state regulations. Production wells will be filled with grout to approximately five feet below surface grade. The top five feet will be overdrilled and filled with soil backfill to grade on top of the grout. Monitoring wells will remain intact.

30. 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.
31. Any observable surface spill will be cleaned up.
32. All trash, debris, and miscellaneous waste will be removed and disposed of properly.
33. 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.
34. Underground piping will be capped and abandoned in place. Circulating water tunnels will be filled with flowable fill.
35. 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.
36. Handling and disposal of hazardous material will be performed in compliance with the approved methods of DEK's Environmental Services Department.
37. Ash ponds and landfills are excluded from the scope of this Study.
38. Storm water ponds will be drained and the area graded out to allow for natural drainage.
39. Site areas will be graded to achieve suitable site drainage to natural drainage patterns, but grading will be minimized to the extent possible.
40. 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.
41. 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.
42. Valuation and sale of land and all replacement generation costs are excluded from this scope.
43. Spare parts inventories were not provided to Burns & McDonnell for review. Burns & McDonnell assumes that to the extent possible spare parts will be sold prior to decommissioning and remaining spare parts will be scrapped by the demolition contractor.
44. Rolling stock, including rail cars, dozers, plant vehicles, etc. is assumed to be removed by DEK prior to decommissioning.

45. 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.
46. A 20 percent contingency was included on the direct costs in the estimates prepared as part of this Study to cover unknowns.
47. 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 5 percent was included in the estimates to cover such costs.
48. Market conditions may result in cost variations at the time of contract execution.

4.2 Site Specific Decommissioning Assumptions

The following assumptions were made specific to each plant cost estimate.

4.2.1 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. Scrap values, net of transportation costs, used in the Study are as follows:
   a. Steel $174.62/ton
   b. Copper $1.74/lb
   c. Aluminum $0.42/lb
   d. Brass $1.31/lb

4.2.2 Miami Fort – Retirement in Place

5. Due to continued operation of Unit 7, and Unit 8 owned by Dynegy, and for purposes of maintaining structural integrity of plant facilities, assets owned by DEK will not be removed from the plant under the retirement in place scenario unless they pose a safety risk.
6. Both precipitators, old and new, and induced draft fans associated with Unit 6 will be removed. The old precipitator is currently seen as a safety hazard if it were to be retired in place, due to its vintage, and the new precipitator would require routine maintenance if retired in place and, therefore, it is assumed that they both will be removed.
7. Asbestos abatement of all DEK owned assets will precede any other work.
8. Materials from the demolition of Unit 6 precipitators will be scrapped and moved off-site.
9. Oil-filled transformers will be drained and the oil disposed of properly.
10. The chimney will be capped.

11. Fuel oil tanks in underground vault will be cleaned, flushed, and abandoned in place.

4.2.3 Miami Fort – Full Demolition

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. The full demolition costs are in addition to the Retire in Place costs that will be incurred.
2. The full demolition costs include only the assets owned by DEK. These assets include Unit 6 boiler and steam turbine, three conveyors (#11, #12, and conveyer G), Unit 5 coal crusher, Unit 5 vacuum pump, and the exhaust stack. The building housing the four steam turbines is assumed to be 25 percent owned by DEK and, therefore, 25 percent of the demolition costs will be paid for by DEK.
3. The chimney is assumed to be imploded upon the retirement of all of the currently operating units owned by Dynegy due to the cost to remove the stacks mechanically with adjacent units in operation being approximately ten times that of implosion.
4. It is assumed that no material was removed from the site during construction; therefore, borrow material is available on-site to be used to backfill the basement.
5. Due to the vintage of the plant, lead based paint is assumed to be present.
6. Mooring cells and barge unloading facilities are not included in the scope of this Study.
7. Scrap values, net of transportation costs, used in the Study are as follows:
    a. Steel $180.68/ton
    b. Copper $1.74/lb
    c. Aluminum $0.42/lb
    d. Brass $1.34/lb
    e. Stainless steel $0.66/lb

4.2.4 East Bend

1. Due to the vintage of the plant it is assumed no asbestos or lead paint is 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. 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 available on-site to be used to backfill the basement.
6. Scrap values, net of transportation costs, used in the Study are as follows:
    a. Steel $176.3/ton

b. Copper $1.74/lb

c. Aluminum $0.42/lb

d. Brass $1.33/lb

e. Stainless steel $0.65/lb

4.3 Results

Table 4-1 presents a summary of the decommissioning cost for each Plant. This summary provides a breakout of the major decommissioning activities and the scrap value for the Plant.

Table 4-1: Decommissioning Cost Estimate Summary (2016$)

Plant	Decommissioning Costs	Credits	Net Project Cost
Woodsdale Station	$ 10,067,000	$ (3,800,000)	$ 6,267,000
Miami Fort Station Unit 6 – Retire in Place [1]	$ 13,046,000	$ (257,000)	$ 12,789,000
Miami Fort Station Unit 6– Full Demolition [2]	$ 5,754,000	$ (1,903,000)	$ 3,851,000
East Bend Station	$ 42,321,000	$ (7,987,000)	$ 34,334,000

Notes:
[1]: Retire in Place costs are assumed to be incurred in the near term to reduce environmental liabilities and risks associated with a non-operating unit.
[2]: The Full Demotion costs are in addition to the Retire in Place costs and are assumed to take place after the retirement of all of the currently operating units owned by Dynegy.

APPENDIX A - PLANT AERIALS

Figure 1: Woodsdale Station

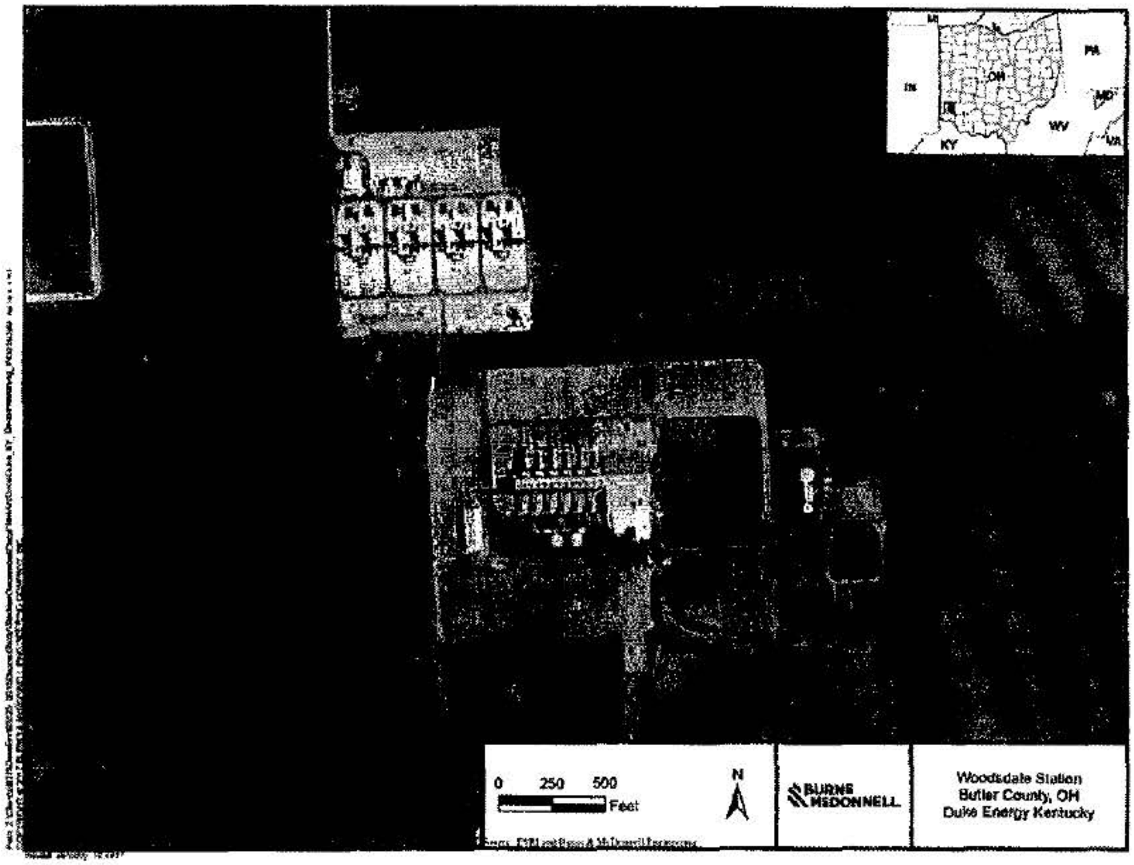


Figure 2: Miami Fort Station

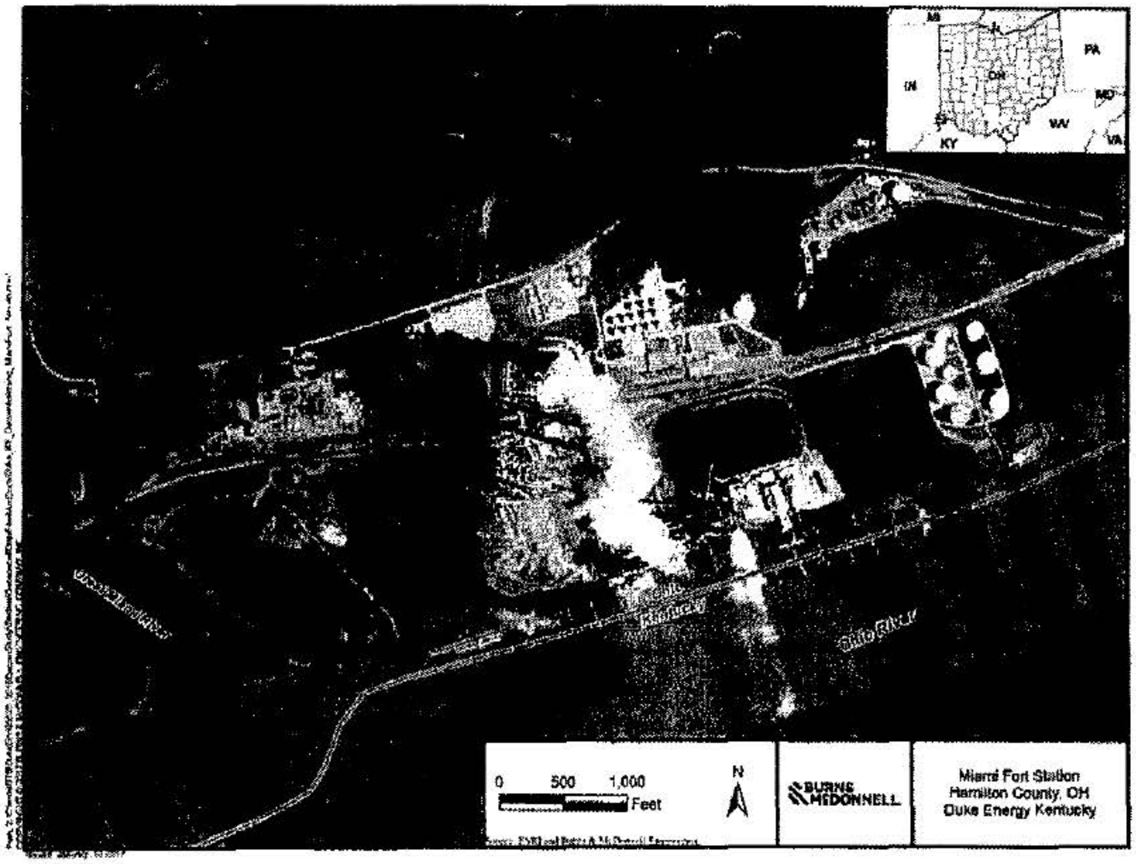
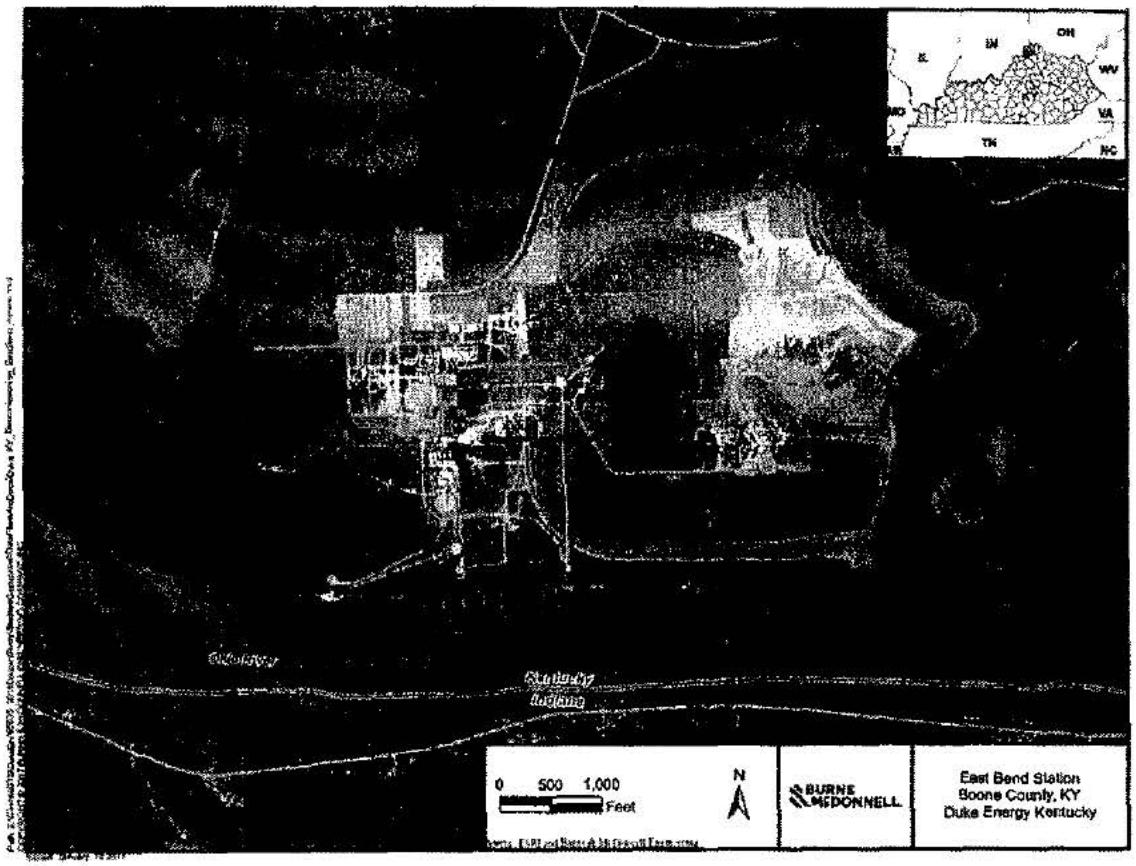


Figure 3: East Bend Station



APPENDIX B - COST ESTIMATE SUMMARIES

Table B-1
Woodsdale
Decommissioning Cost Summary

Woodsdale	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Unit 1 - 6						
CTs	$ 1,752,000	$ 2,038,000	$ -	$	$ 3,790,000	$
Stack (Metal)	$ 34,000	$ 40,000	$ -	$ -	$ 74,000	$
GSUs, Electical, & Foundation	$ 124,000	$ 145,000	$ -	$ -	$ 269,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 33,000	$ -	$ 33,000	$ -
Debris	$ -	$ -	$ 1,000	$ -	$ 1,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (3,502,000)
Subtotal	**$ 1,910,000**	**$ 2,223,000**	**$ 34,000**	**$ -**	**$ 4,167,000**	**$ (3,502,000)**
Common						
Water Treatment Equipment and Piping	$ 351,000	$ 408,000	$	$ -	$ 758,000	$ -
Roads	$ 409,000	$ 476,000	$	$ -	$ 886,000	$
All BOP Buildings	$ 377,000	$ 439,000	$	$ -	$ 817,000	$ -
All Other Tanks	$ 191,000	$ 222,000	$ -	$ -	$ 413,000	$
Propane Boiler	$ 113,000	$ 131,000	$	$ -	$ 244,000	$
Switchgear & Electrical	$ 5,000	$ 6,000	$	$ -	$ 11,000	$
Transformer Oil Cleanup	$ -	$ -	$	$ 161,000	$ 161,000	$
Transformer Pad and Soil Removal	$ -	$	$	$ 85,000	$ 85,000	$
Plant Wash Down and Cleanup	$ -	$	$	$ 69,000	$ 69,000	$
Mercury and Universal Waste Cleanup	$ -	$	$ -	$ 11,000	$ 11,000	$ -
Battery Removal	$	$	$ -	$ 10,000	$ 10,000	$ -
Concrete Removal, Crushing, & Disposal	$ -	$	$ 76,000	$ -	$ 76,000	$
Grading & Seeding	$ -	$	$ -	$ 340,000	$ 340,000	$
Debris	$	$	$ 5,000	$ -	$ 5,000	$ -
Scrap	$ -	$	$ -	$ -	$ -	$ (298,000)
Subtotal	**$ 1,446,000**	**$ 1,682,000**	**$ 81,000**	**$ 676,000**	**$ 3,886,000**	**$ (298,000)**
Woodsdale Subtotal	**$ 3,356,000**	**$ 3,905,000**	**$ 115,000**	**$ 676,000**	**$ 8,053,000**	**$ (3,800,000)**
TOTAL DECOM COST (CREDIT)					**$ 8,053,000**	**$ (3,800,000)**
PROJECT INDIRECTS (5%)					**$ 403,000**	
CONTINGENCY (20%)					**$ 1,611,000**	
TOTAL PROJECT COST (CREDIT)					**$ 10,067,000**	**$ (3,800,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 6,267,000**	

Table B-2
Miami Fort
Decommissioning Cost Summary - Retire in Place

Description		One Time Costs		Scrap Value
Miami Fort				
Unit 6				
Asbestos Abatement	$	6,253,000	$	-
Shutdown Plant Equipment & Structures	$	48,000	$	-
Site Cleanup	$	12,000	$	-
Precipitator Removal	$	4,124,000	$	(257,000)
Retirement in Place Subtotal	**$**	**10,437,000**	**$**	**(257,000)**
TOTAL RETIRE IN PLACE COST (CREDIT)	**$**	**10,437,000**	**$**	**(257,000)**
PROJECT INDIRECTS (5%)	**$**	**522,000**		
CONTINGENCY (20%)	**$**	**2,087,000**		
TOTAL PROJECT COST (CREDIT)	**$**	**13,046,000**	**$**	**(257,000)**
TOTAL NET PROJECT COST (CREDIT)	**$**	**12,789,000**		

*Note: Due to future degradation, the cost to mechanically demolish the chimney prior to shut-down of Units 7 & 8 would cost up to approximately $3.9 million based on recent demolition contractor bids.

Table B-3
Miami Fort
Decommissioning Cost Summary - Full Demolition

Miami Fort	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Unit 6						
Boiler	$ 997,000	$ 1,159,000	$ -	$ -	$ 2,156,000	$
Steam Turbine & Building	$ 449,000	$ 523,000	$ -	$ -	$ 972,000	$
Cooling Water Intakes and Circulating Water Pumps	$ 18,000	$ 21,000	$ -	$ -	$ 39,000	$ -
NSCR	$ 54,000	$ 110,000	$ -	$ -	$ 204,000	$ -
Switchgear & Electrical	$ 10,000	$ 12,000	$ -	$ -	$ 21,000	$
Stacks	$ 159,000	$ 165,000	$ -	$ -	$ 343,000	$ -
GSU & Foundation	$ 37,000	$ 43,000	$ -	$ 2,000	$ 82,000	$ -
Hazardous Materials Disposal	$ -	$ -	$ 10,000	$ -	$ 10,000	$ -
On-site Concrete Crushing & Disposal	$ -	$	$ 131,000	$ -	$ 131,000	$ -
Debris	$ -	$ -	$ 38,000	$ -	$ 38,000	$ -
Scrap	$ -	$	$ -	$ -	$ -	$ (1,873,000)
Subtotal	**$ 1,764,000**	**$ 2,053,000**	**$ 179,000**	**$ 2,000**	**$ 3,996,000**	**$ (1,873,000)**
Handling						
Coal Handling Demolition	$ 37,000	$ 43,000	$ -	$	$ 80,000	$
On-site Concrete Crushing & Disposal	$ 3,000	$ 4,000	$ -	$ -	$ 7,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (30,000)
Subtotal	**$ 40,000**	**$ 47,000**	**$ -**	**$ -**	**$ 87,000**	**$ (30,000)**
Common						
Transformers Transformer Oil Cleanup	$ -	$	$	$ 3,000	$ 3,000	$
Transformers Pad and Soil Removal	$ -	$ -	$	$ 8,000	$ 8,000	$ -
Refractory Cleanup	$ -	$ -	$	$ 33,000	$ 33,000	$ -
Plant Wash Down and Cleanup	$ -	$	$	$ 32,000	$ 32,000	$
Mercury and Universal Waste Cleanup	$ -	$ -	$	$ 11,000	$ 11,000	$ -
Nuclear Device Cleanup	$ -	$	$ -	$ 6,000	$ 6,000	$
Battery Removal	$ -	$	$	$ 10,000	$ 10,000	$ -
Grading & Seeding	$ -	$	$	$ 417,000	$ 417,000	$ -
Subtotal	**$ -**	**$ -**	**$ -**	**$ 520,000**	**$ 520,000**	**$ -**
Miami Fort Subtotal	**$ 1,804,000**	**$ 2,100,000**	**$ 179,000**	**$ 522,000**	**$ 4,603,000**	**$ (1,903,000)**
TOTAL DECOM COST (CREDIT)					**$ 4,603,000**	**$ (1,903,000)**
PROJECT INDIRECTS (5%)					**$ 230,000**	
CONTINGENCY (20%)					**$ 921,000**	
TOTAL PROJECT COST (CREDIT)					**$ 5,754,000**	**$ (1,903,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 3,851,000**	

Table B-4
East Bend
Decommissioning Cost Summary

East Bend	Labor	Material and Equipment	Disposal	Environmental	Total Cost	Scrap Value
Unit 2						
Boiler	$ 3,491,000	$ 4,061,000	$	$ -	$ 7,552,000	$ -
Steam Turbine & Building	$ 1,439,000	$ 1,674,000	$ -	$ -	$ 3,113,000	$
Precipitator	$ 1,002,000	$ 1,165,000	$ -	$ -	$ 2,167,000	$
SCR	$ 606,000	$ 705,000	$ -	$ -	$ 1,311,000	$ -
Switchgear & Electrical	$ 10,000	$ 12,000	$ -	$ -	$ 22,000	$
Scrubber / FGD	$ 700,000	$ 815,000	$ -	$ -	$ 1,515,000	$ -
Stacks	$ 237,000	$ 275,000	$ -	$ -	$ 512,000	$
Cooling Towers & Basin	$ 714,000	$ 831,000	$ -	$ -	$ 1,545,000	$
GSU & Foundation	$ 65,000	$ 76,000	$ -	$ -	$ 141,000	$
On-site Concrete Crushing & Disposal	$ -	$ -	$ 378,000	$ -	$ 378,000	$ -
Debris	$ -	$ -	$ 61,000	$ -	$ 61,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (6,964,000)
Subtotal	**$ 8,264,000**	**$ 9,614,000**	**$ 438,000**	**$ -**	**$ 18,317,000**	**$ (6,964,000)**
Handling						
Coal Handling Demolition	$ 465,000	$ 541,000	$	$	$ 1,006,000	$ -
Grab Bucket and Coal Unloading Facilities	$ 720,000	$ 851,000	$	$ -	$ 1,571,000	$
Coal Storage Area Restoration	$ -	$ -	$	$ 4,828,000	$ 4,828,000	$
Limestone/Gypsum Handling Facilities	$ 189,000	$ 220,000	$ -	$ -	$ 409,000	$ -
On-site Concrete Crushing & Disposal	$ -	$ -	$ 30,000	$ -	$ 30,000	$ -
Scrap	$ -	$ -	$ -	$ -	$ -	$ (438,000)
Subtotal	**$ 1,374,000**	**$ 1,612,000**	**$ 30,000**	**$ 4,828,000**	**$ 7,844,000**	**$ (438,000)**
Common						
Cooling Water Intakes & Circ. Water Equip.	$ 59,000	$ 69,000	$ -	$ 845,000	$ 973,000	$
Roads	$ 631,000	$ 734,000	$ 741,000	$ -	$ 2,106,000	$ -
All BOP Buildings	$ 684,000	$ 795,000	$ -	$	$ 1,479,000	$
Fuel Oil Equipment	$ 22,000	$ 26,000	$ -	$	$ 48,000	$ -
All Other Tanks	$ 180,000	$ 209,000	$ -	$	$ 389,000	$ -
Transformers & Foundation	$ 84,000	$ 97,000	$ -	$ -	$ 181,000	$ -
Transformers Oil Cleanup	$ -	$ -	$ -	$ 153,000	$ 153,000	$ -
Transformers Pad and Soil Removal	$	$	$ -	$ 49,000	$ 49,000	$
Refractory Cleanup	$	$	$ -	$ 16,000	$ 16,000	$
Plant Wash Down and Cleanup	$ -	$	$ -	$ 32,000	$ 32,000	$ -
Mercury and Universal Waste	$	$	$ -	$ 11,000	$ 11,000	$ -
Fuel Oil Tank Soil Cleanup	$	$	$ -	$ 10,000	$ 10,000	$
Fuel Oil Tank Cleanup	$	$	$ -	$ 13,000	$ 13,000	$
Fuel Oil Line Flushing/Cleanup	$	$	$ -	$ 3,000	$ 3,000	$
Concrete Removal, Crushing, & Disposal	$	$ -	$ 60,000	$ -	$ 60,000	$ -
Grading & Seeding	$	$ -	$ -	$ 2,167,000	$ 2,167,000	$
Debris	$	$	$ 6,000	$ -	$ 6,000	$ -
Scrap	$	$ -	$ -	$ -	$ -	$ (585,000)
Subtotal	**$ 1,660,000**	**$ 1,930,000**	**$ 807,000**	**$ 3,299,000**	**$ 7,696,000**	**$ (585,000)**
East Bend Subtotal	**$ 11,298,000**	**$ 13,156,000**	**$ 1,276,000**	**$ 8,127,000**	**$ 33,857,000**	**$ (7,987,000)**
TOTAL DECOM COST (CREDIT)					**$ 33,857,000**	**$ (7,987,000)**
PROJECT INDIRECTS (5%)					**$ 1,693,000**	
CONTINGENCY (20%)					**$ 6,771,000**	
TOTAL PROJECT COST (CREDIT)					**$ 42,321,000**	**$ (7,987,000)**
TOTAL NET PROJECT COST (CREDIT)					**$ 34,334,000**	

BURNS McDONNELL

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EXHIBIT ____ (LK-28)

AG-DR-01-031

REQUEST:

Refer to pages VIII-2 through VIII-4 of the Gannett Fleming Depreciation Study which shows an escalation of Decommissioning estimates to future values. Provide the rate of escalation assumed in these calculations and explain why that rate is appropriate. In addition, provide a copy of the source of the Decommissioning estimates before application of escalation rates to future values.

RESPONSE:

An escalation factor of 2.5% was used to determine the future values shown in the depreciation study. The decommissioning costs established in the Burns & McDonnell study (provided as an attachment to request AG-DR-01-026) were reported in 2016 dollars. Since the units will not be retired until 2032 and 2041, it is appropriate to escalate the decommissioning costs annually to the date of retirement. The 2.5% escalation factor is the same as used in the prior rate case which was approved. This is a commonly utilized escalation factor which is based on widely accepted measures of inflation such as the Consumer Price Index and the Handy Whitman Index as examples.

PERSON RESPONSIBLE: John J. Spanos

EXHIBIT ____ (LK-29)

AG-DR-02-001

REQUEST:

Reference the response to AG 1-1. The request sought the projected remaining lifespan of the Woodsdale CT units by unit, and the East Bend facility. The response that the stations are expected to run through the IRP planning period is non-responsive to the request. Provide a response to the request sought: Provide the projected remaining lifespan of the Woodsdale CT units by unit and of the East Bend facility.

RESPONSE:

The most recent Depreciation Study completed December 31, 2016 assigned a life span estimate of 60 years for East Bend 2 which would imply an end of life date of 2041 based on the in-service date of 1981. A lifespan of 40 years was assigned to the CT units at Woodsdale implying an end of life date of 2032 for each of the Woodsdale units based on the in-service date of 1992. The remaining lifespan of any of these units can be extended through additional capital expenditure if deemed economically prudent at the time the additional investment is required by the physical condition of the unit.

PERSON RESPONSIBLE: Scott Park

EXHIBIT ____ (LK-30)

REQUEST:

Refer to the Jacobi Testimony, page 12, lines 13-20. Refer also to the application, Volume 11, Schedule J-3.

a. Provide documentation and all calculations for the long-term interest cost on the $25 million of LT Commercial Paper for the base and forecast period.

b. Explain why Duke Kentucky chose the credit spread to be 25-basis points of the LT Commercial Paper.

c. Provide documentation and all calculations for the long-term interest cost of the Variable Debt of $26,720,000 for the base and forecast period.

d. Provide documentation and all calculations for the long-term interest cost of the September 2020 forecasted debenture.

e. Explain why Duke Kentucky chose a credit spread of 162-basis point for the September 2020 forecasted debenture.

f. Provide the spread added to the long-term debt, if any were forecasted, for Duke Kentucky's last two electric base rate cases.

RESPONSE:

a. Please see the table below for the calculation of interest on long-term commercial paper in the base period and forecast period. Attachments STAFF-DR-02-054a Attachment 1 and STAFF-DR-02-054a Attachment 2 show the 1-month LIBOR forward curve used in the calculation below

	Long-term Commercial Paper Balance	Forward 1M LIBOR	Forecasted Spread to 1M LIBOR	Forecasted interest rate	Forecasted Interest Cost
	A	B	C	D=B+C	E=A*D
Nov-19	$25,000,000	1.69%	0.25%	1.94%	$485,790
Mar-20	$25,000,000	1.60%	0.25%	1.85%	$461,578
Apr-20	$25,000,000	1.60%	0.25%	1.85%	$461,578
May-20	$25,000,000	1.56%	0.25%	1.81%	$452,990
Jun-20	$25,000,000	1.50%	0.25%	1.75%	$438,205
Jul-20	$25,000,000	1.50%	0.25%	1.75%	$438,205
Aug-20	$25,000,000	1.48%	0.25%	1.73%	$432,238
Sep-20	$25,000,000	1.44%	0.25%	1.69%	$422,792
Oct-20	$25,000,000	1.44%	0.25%	1.69%	$422,792
Nov-20	$25,000,000	1.44%	0.25%	1.69%	$423,160
Dec-20	$25,000,000	1.44%	0.25%	1.69%	$423,553
Jan-21	$25,000,000	1.44%	0.25%	1.69%	$423,553
Feb-21	$25,000,000	1.43%	0.25%	1.68%	$420,371
Mar-21	$25,000,000	1.40%	0.25%	1.65%	$413,654
				13-month average:	**$433,436**

b. The 25 basis point credit spread used for the Company's LT Commercial Paper rate is the estimated credit spread over LIBOR for the Company's Commercial Paper borrowings over time. Recent history of the Company's Commercial Paper rate versus 1-month LIBOR supports using a credit spread in this range. See below for some sample dates:

	Weighted Average Commercial Paper Rate	1 Month LIBOR	Spread of Commercial Paper Rate over 1M LIBOR
	A	B	C=A-B
12/31/18	2.79%	2.52%	0.27%
1/31/19	2.77%	2.51%	0.26%
2/28/19	2.77%	2.49%	0.28%
3/31/19	2.73%	2.49%	0.24%
4/30/19	2.69%	2.48%	0.21%
5/31/19	2.67%	2.43%	0.24%
6/30/19	2.59%	2.40%	0.19%
7/31/19	2.52%	2.22%	0.29%
8/31/19	2.30%	2.09%	0.21%
9/30/19	2.19%	2.02%	0.17%

c. The $26.7 million pollution control bond was swapped to a fixed rate of 3.86% in August 2006.

d. See attachment STAFF-DR-02-54d Attachment 1 for the forward US Treasury rate curve as of 9/15/2020 for the 5-year, 10-year, and 30-year Treasury rates used in the calculation below.

	Tenor	Weight	9/15/2020 UST	Current Spread	Cpn
	5-yr	10%	1.85%	1.30%	3.15%
	10-yr	35%	2.16%	1.50%	3.66%
	30-yr	55%	2.62%	1.75%	4.37%
Weighted Average	**20.5-yr**		**2.38%**	**1.62%**	**4.00%**

e. On June 21, Duke Energy Kentucky priced a $210 million private placement debt issuance split into three tranches: $95 million, 6-year fixed rate debentures at 3.23%; $75 million, 10-year fixed rate debentures at 3.56%; and $40 million, 30-year fixed rate debentures at 4.32%. Duke Energy Kentucky's credit spreads across the 6-year, 10-year, and 30-year tranches were 135 basis points, 150 basis points, and 175 basis points, respectively. The Company also received a pricing indication on 5-year fixed rate debentures of 130 basis points.

The interest rate on the planned September 2020 debt issuance was estimated using a blended average of Bloomberg's forward curves for the 5-year, 10-year, and 30-year US Treasury yield plus an estimated credit spread for a future debt issuance. In June 2019, forward treasury rates reflected 1.85% for the 5-year, 2.16% for the 10-year, and 2.62% for the 30-year. Since there is no forward curve for credit spreads, we used the then-current credit spreads for Duke Energy Kentucky. Adding the forward treasury rates and credit spreads amounted to rates of 3.15% on the 5-year, 3.66% on the 10-year, and 4.37% on the 30-year. Blending those averages together with a 10% weight given to the 5-year tranche, a 35% weight given to the 10-year tranche, and a 55% weight given to the 30-year tranche resulted in a weighted average credit spread of 162 basis points and a forecasted rate of 4.00%. See table above for the calculation of the forecasted long-term debt rate.

f. The credit spreads utilized for forecasted long-term debt in Case No. 2018-00261 and Case No. 2017-00321 were 158 and 145 basis points, respectively.

PERSON RESPONSIBLE: Christopher Jacobi

<Back> to Return

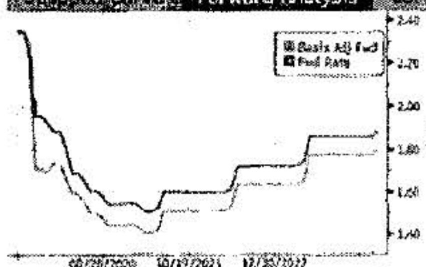
Actions | Modes | Settings | Swap Curve Builder

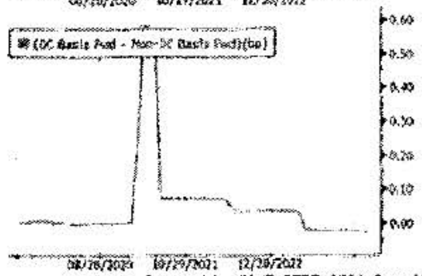
USD | 50 - USD (vs. 1M LIBOR) | Name USD (vs. 1M LIBOR) | Default | Privilege Global | 06/21/19

Curve Construction | Curve Analysis

Curve #	50 - USD (vs. 1M LIBOR)	Shift	+0.00 bp
Interpolation	Step Forward (Cont)	OIS DC Stripping	Yes
Settle Date	06/30/19	Index Fixing	US0001M 2.40438%
Curve Side	Mid	Basis Side	Mid

Stripped Curve | Forward Analysis | Curve Horizon





Interval 1 M | Tenor 1 M | Up to 5 Yr

Date	Fwd R...	Basis Adj F...	Diff (b...	Non-DC F...	Non-DC Basis ...	Non-DC Diff ...
06/30/2019	2.3491	2.3362	-1.29	2.3491	2.3362	-1.29
07/31/2019	2.3491	2.3362	-1.29	2.3491	2.3362	-1.29
08/30/2019	2.2854	2.2353	-5.00	2.2854	2.2353	-5.00
09/30/2019	1.9541	1.7112	-24.30	1.9541	1.7111	-24.31
10/31/2019	1.9541	1.7112	-24.30	1.9541	1.7111	-24.31
11/29/2019	1.9269	1.6932	-23.37	1.9269	1.6931	-23.38
12/31/2019	1.8837	1.7363	-14.74	1.8837	1.7363	-14.74
01/31/2020	1.8837	1.7363	-14.74	1.8837	1.7363	-14.74
02/28/2020	1.8098	1.6706	-13.91	1.8098	1.6706	-13.92
03/31/2020	1.6927	1.5963	-9.64	1.6927	1.5963	-9.63
04/30/2020	1.6927	1.5963	-9.64	1.6927	1.5963	-9.63
05/29/2020	1.6592	1.5620	-9.73	1.6592	1.5620	-9.72
06/30/2020	1.6063	1.5028	-10.35	1.6063	1.5028	-10.35
07/31/2020	1.6063	1.5028	-10.35	1.6063	1.5028	-10.35
08/28/2020	1.5824	1.4790	-10.35	1.5824	1.4790	-10.34
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

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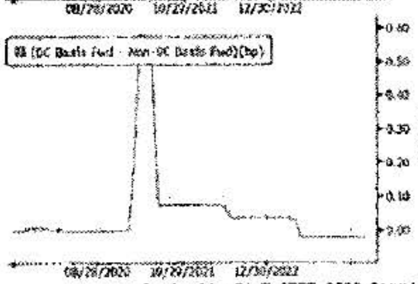
Actions | Modes | Settings | Swap Curve Builder

USD | 50 - USD (vs. 1M LIBOR) | Name USD (vs. 1M LIBOR) | Default | Privilege Global | 06/21/19

Curve Construction | Curve Analysis

Curve #	50 - USD (vs. 1M LIBOR)	Shift	+0.00 bp
Interpolation	Step Forward (Cont)	OIS DC Stripping	Yes
Settle Date	06/30/19	Index Fixing	US0001M 2.40438%
Curve Side	Mid	Basis Side	Mid

Stripped Curve | Forward Analysis | Curve Horizon



Interval 1 M | Tenor 1 M | Up to 5 Yr

Date	Fwd R...	Basis Adj F...	Diff (b...	Non-DC F...	Non-DC Basis ...	Non-DC Diff ...
06/30/2020	1.6063	1.5028	-10.35	1.6063	1.5028	-10.35
07/31/2020	1.6063	1.5028	-10.35	1.6063	1.5028	-10.35
08/28/2020	1.5824	1.4790	-10.35	1.5824	1.4790	-10.34
09/30/2020	1.5446	1.4412	-10.35	1.5446	1.4412	-10.34
10/30/2020	1.5446	1.4412	-10.35	1.5446	1.4412	-10.34
11/30/2020	1.5461	1.4426	-10.35	1.5461	1.4427	-10.34
12/31/2020	1.5477	1.4442	-10.35	1.5477	1.4442	-10.34
01/29/2021	1.5477	1.4442	-10.35	1.5477	1.4442	-10.34
02/26/2021	1.5349	1.4315	-10.35	1.5331	1.4296	-10.34
03/31/2021	1.5081	1.4046	-10.34	1.5023	1.3988	-10.34
04/30/2021	1.5081	1.4046	-10.34	1.5023	1.3988	-10.34
05/28/2021	1.5168	1.4148	-10.20	1.5115	1.4095	-10.20
06/30/2021	1.5988	1.5099	-8.89	1.5980	1.5092	-8.88
07/30/2021	1.5988	1.5099	-8.89	1.5980	1.5092	-8.88
08/31/2021	1.5988	1.5099	-8.89	1.5980	1.5092	-8.88

Cancel: Screen not saved

US Treasury Actives Curve | Export | Graph | Forward Curve Matrix

US Treasury Actives Curve — Mid · Yield — Conventional — « Curve List

☐ Two Curve Spreads

Select a curve under "Curve List" for two curre… Bid · Yield — Conventional

Forward Curve Date 09/15/20 — ☐ OIS Discounting

Spot ◉ Coupon ◉ Zero

		Forwards										
Tenors	Coupon	9/15/2020	3Mo	6Mo	1Yr	2Yr	3Yr	4Yr	5Yr	10Yr	15Yr	30Yr
1Mo	2.1155	1.5410	1.9621	1.7932	1.5204	1.5828	1.8348	1.8348	2.1954	2.8994	2.8994	2.8997
2Mo	2.1215	1.5505										
3Mo	2.1098	1.5430	1.9555	1.7763	1.5391	1.6112	1.8682	1.8681	2.2237	2.9548	2.9548	2.9548
6Mo	2.0561	1.5290	1.8648	1.7816	1.5336	1.6054	1.8619	1.8622	2.2177	2.9493	2.9495	2.9489
1Yr	1.9230	1.5602	1.7641	1.6581	1.5342	1.6075	1.8571	1.8874	2.2116	2.9414	2.9414	2.9414
2Yr	1.7375	1.6138	1.6589	1.6143	1.5705	1.7316	1.8712	2.0478	2.2176	2.9414	2.9454	2.9414
3Yr	1.6918	1.6935	1.6634	1.6545	1.6648	1.7817	1.9823	2.1055	2.2762	2.9440	2.9441	2.9440
5Yr	1.7566	1.8476	1.7613	1.7727	1.8131	1.9508	2.1090	2.2195	2.3358	2.9430	2.9431	2.9430
7Yr	1.8822	1.9799	1.8916	1.9060	1.9477	2.0726	2.1957	2.3478	2.4976	2.9437	2.9437	2.9437
10Yr	2.0254	2.1642	2.0502	2.0727	2.1271	2.2659	2.4005	2.5105	2.6191	2.9431	2.9438	2.9431
30Yr	2.5576	2.6177	2.5630	2.5722	2.5946	2.6528	2.7097	2.7566	2.8032	2.9433	2.9436	2.9433

Grey values are extrapolated.

EXHIBIT ____ (LK-31)

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BONDS & RATES

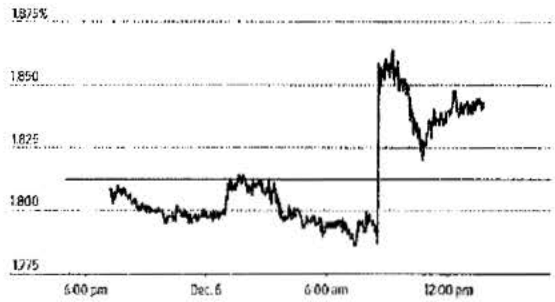
U.S. Treasurys

1:41 PM EST 12/06/19

	COUPON (%)	PRICE CHG	YIELD (%)	YIELD CHG
30-Year Bond	2.375	-5/32	2.282	0.023
10-Year Note	1.75	-3/32	1.842	0.030
7-Year Note	1.625	-2/32	1.774	0.033
5-Year Note	1.5	-2/32	1.666	0.033
3-Year Note	1.625	-23/32	1.641	0.036
2-Year Note	1.5	-1/32	1.617	0.029
1-Year Bill	0	0/32	1.569	0.000
6-Month Bill	0	0/32	1.547	-0.005
3-Month Bill	0	-1/32	1.525	-0.021
1-Month Bill	0	0/32	1.512	-0.005

View Treasury Quotes Page

10-Year Note



10-Year Note 1D 5D 3M YTD 1Y 3Y

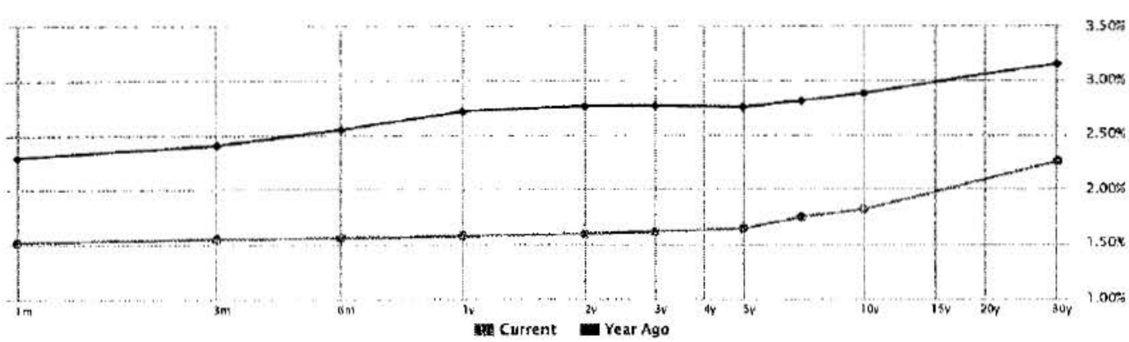
Bonds & Rates News

U.S. Government Bond
4 hours ago

Treasury to Sell $156 B
20 hours ago

Twitter Sells Bonds at
21 hours ago

Yield Curve



LIBOR Rates

12/06/19

Rates shown are effective 12/05/19

Libor Rates (USD) | Euro Libor Rates | Pound Libor Rates | Yen Libor Rates

	LATEST	WK AGO	52-WEEK HIGH	52-WEEK LOW
Libor Overnight	1.52938	1.53963	2.40275	1.52700
Libor 1 Week	1.57475	1.58625	2.43088	1.57238
Libor 1 Month	1.71013	1.70850	2.52238	1.69113
Libor 2 Month	1.82238	1.83575	2.65288	1.82238
Libor 3 Month	1.88500	1.90688	2.82375	1.88500
Libor 6 Month	1.88813	1.89513	2.90788	1.88750
Libor 1 Year	1.92263	1.95025	3.11238	1.85313

EXHIBIT ____ (LK-32)

Duke Energy Kentucky
Case No. 2019-00271
Staff's Second Set Data Requests
Date Received: October 11, 2019

STAFF-DR-02-086

REQUEST:

Refer to the Lawler Testimony, page 16, lines 9-11. Provide the calculation of the revenue requirement impact of Duke Kentucky's proposed battery storage project.

RESPONSE:

See Staff-DR-02-086 Attachment.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Estimated Revenue Requirement
Battery Storage Project

Line	Description	Test Period
1	Gross Plant[a]	$2,508,971
2	Accum Depreciation [b]	(83,632)
3	Net Plant in Service	$2,425,339
4	Accum Def Income Taxes on Plant [b]	($8,781)
5	Rate Base	**$2,416,558**
6	Return on Rate Base (Pre-Tax %) [c]	8.96%
7	Return on Rate Base (Pre-Tax)	$216,451
8	Depreciation Expense	83,632
9	Annualized Property Tax Expense [d]	46,081
10	Revenue Requirement (Lines 7 - 9)	$346,165

Assumptions:

[a] Schedule B-2.1 Page 10 of 12, Line 6

[b] Assumes 15 year book life; 15 year MACRS

[c] Weighted-Average Cost of Capital from Schedule A in Case No. 2019-00271, with ROE at 9.8%, grossed up for 21% FIT rate.

[d] Assumes 1.9% of net plant.

Duke Energy Kentucky
Estimated Revenue Requirement
Battery Storage Project

Line	Description	Test Period												
		Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
1	Placed in Service	-	-	-	-	-	-	-	-	-	8,154,156	-	-	-
2	Culmative Plant In Service	-	-	-	-	-	-	-	-	-	8,154,156	8,154,156	8,154,156	8,154,156
3	13 Month Average (Average of Ln 2):	2,508,971												

EXHIBIT ____ (LK-33)

Duke Energy Kentucky
Case No. 2019-00271
Staff's Second Set Data Requests
Date Received: October 11, 2019

STAFF-DR-02-088

REQUEST:

Refer to the Lawler Testimony, page 17, lines 9-11. Provide the calculation of the revenue requirement impact of Duke Kentucky's proposed electric vehicles pilot programs.

RESPONSE:

See Staff-DR-02-088 Attachment.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Estimated Revenue Requirement
Electric Vehicle Project

Line	Description	Test Period
1	Gross Plant[a]	$846,154
2	Accumulated Depreciation	(60,440)
3	Net Plant in Service	$785,714
4	Accum Def Income Taxes on Plant [b]	($12,700)
5	Rate Base	**$773,014**
6	Return on Rate Base (Pre-Tax %) [c]	8.96%
7	Return on Rate Base (Pre-Tax)	$69,239
8	Depreciation Expense	60,440
9	Annualized Property Tax Expense [d]	14,929
10	Revenue Requirement (Lines 7 - 9)	$144,607

Assumptions:
[a] Page 2 Ln 3
[b] Assumes 7 year book life; 7 year MACRS
[c] Weighted-Average Cost of Capital from Schedule A in Case No. 2019-00271, with ROE at 9.8%, grossed up for 21% FIT rate.
[d] Assumes 1.9% of net plant.

Duke Energy Kentucky
Estimated Revenue Requirement
Electric Vehicle Project

Line	Description	Test Period												
		Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
1	Placed in Service	-	-	-	275,000	275,000	275,000	275,000	275,000	-	-	-	-	-
2	Culmative Plant In Service	-	-	-	275,000	550,000	825,000	1,100,000	1,375,000	1,375,000	1,375,000	1,375,000	1,375,000	1,375,000
3	13 Month Average (Average of Ln 2):	846,154												