**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF:**

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| **ELECTRONIC APPLICATION OF DUKE** | ) | |
| **ENERGY KENTUCKY, INC. FOR: (1) AN** | ) | |
| **ADJUSTMENT OF THE ELECTRIC RATES;** | ) | |
| **(2) APPROVAL OF NEW TARIFFS;** | ) | **CASE NO. 2024-00354** |
| **(3) APPROVAL OF ACCOUNTING PRACTICES** | ) | |
| **TO ESTABLISH REGULATORY ASSETS AND** | ) | |
| **LIABILITIES; AND (4) ALL OTHER** | ) | |
| **REQUIRED APPROVALS AND RELIEF** | ) | |

# DIRECT TESTIMONY

# AND EXHIBITS

# OF

# RANDY A. FUTRAL

**ON BEHALF OF THE**

**OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**MARCH 5, 2025**

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**IN THE MATTER OF:**

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# DIRECT TESTIMONY OF RANDY A. FUTRAL

## I. QUALIFICATIONS AND SUMMARY

**Q. Please state your name and business address.**

A. My name is Randy A. Futral. 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 Director of Consulting with the firm of Kennedy and Associates.

**Q. Please describe your education and professional experience.**

A. I earned a Bachelor of Business and Science degree in Business Administration with an emphasis in Accounting from Mississippi State University. I have held various positions in the field of accounting for a period of over 40 years, both as an employee and more recently as a consultant. My experience has been focused in the areas of accounting, auditing, tax, budgeting, forecasting, financial reporting, and management.

Since 2003, I have been a consultant with Kennedy and Associates, providing services to state government agencies and large consumers of utility services in the ratemaking, financial, tax, accounting, and management areas.

From 1997 to 2003, I served both as the Corporate Controller and Assistant Controller of Telscape International, Inc., an international public company providing telecommunication and high-end internet access services. My tenure with Telscape included responsibilities in the areas of accounting, financial reporting, budgeting, forecasting, banking, and management.

From 1988 to 1997, I was employed by Comcast Communications, Inc., then the world's third largest cable television provider, in a series of positions including Regional Controller for their South Central regional office. My duties with Comcast encompassed various accounting, tax, budgeting, forecasting, and managerial functions.

From 1984 to 1988, I held various staff and senior level accounting positions for both public accounting and private concerns focusing in the areas of accounting, budgeting, tax, and financial reporting.

I have testified as an expert on ratemaking, accounting, finance, tax, and other issues in proceedings before regulatory commissions at the federal and state levels on numerous occasions. I have also acted as the lead expert in numerous proceedings involving audits of Louisiana fuel adjustment clauses, environmental adjustment clauses, purchase gas adjustment clauses, energy efficiency rider filings, and formula rate plan filings resulting in written reports that were ultimately approved by the Louisiana Public Service Commission.

I previously testified before the Kentucky Public Service Commission ("Commission") as a witness in the last Duke Energy Kentucky, Inc. ("Duke Kentucky" or "Company") base rate proceeding for its electric division in Case No. 2022-00372.[1] I have also previously testified before the Commission as a witness in a Water Service Corporation of Kentucky ("Water Service Kentucky") base rate proceeding in Case No. 2022-00147, in a Kentucky Power Company fuel adjustment clause proceeding in Case No. 2022-00263, and in a Licking Valley Rural Electric Cooperative Corporation base rate proceeding in Case No. 2024-00211. I also filed Direct Testimony in a Kenergy Corporation base rate proceeding in Case No. 2023-00276 and in a Kentucky Power purchased power adjustment tariff update proceeding in Case No. 2023-00318, both of which were decided by the Commission in lieu of formal hearings. Finally, I filed Direct Testimony in a pending Atmos Energy Corporation base rate proceeding in Case No. 2024-00276. I have also assisted counsel for the Office of the Attorney General of the Commonwealth of Kentucky and Kentucky Industrial Utilities Customers, as well as other Kennedy and Associates' experts, in numerous other proceedings before the Commission, including base rate (electric, gas, and water), fuel adjustment clause, and acquisition proceedings

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[1] Case No. 2022-00372, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Oct. 12, 2023).

involving Duke Kentucky, Water Service Kentucky, Kentucky Power Company, Kentucky-American Water Company, Atmos Energy Corporation, Columbia Gas of Kentucky, Inc., Kentucky Utilities Company, Louisville Gas and Electric Company, Big Rivers Electric Corporation, Jackson Purchase Energy Corporation, South Kentucky Rural Electric Cooperative Corporation, and East Kentucky Power Cooperative.[2]

**Q. On whose behalf are you testifying?**

A. I am providing testimony 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's adjustments to reduce Duke Kentucky's requested base revenue requirement and requested rate increase, and 2) address and make recommendations on specific issues that affect the base revenue requirement in this proceeding.

**Q. Please summarize your testimony.**

A. I recommend that the Commission increase the Company's base revenues by no more than $38.093 million, a reduction of at least $31.916 million from the Company's requested base rate increase of $70.008 million. In Table 1 on the following page, I list each of the recommendations by the AG witnesses and the effect of each recommendation on the Company's requested increase.[3] These adjustments were

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[2] My qualifications are further detailed in Exhibit RAF-1.

[3] 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.

developed in consultation with the AG, but I understand that the AG's final adjustments may differ based upon discovery, testimony, and further evidence presented throughout the course of this proceeding.

**Table 1**
**Duke Energy Kentucky, Inc.**
**Case No. 2024-00354**
**Base Revenue Requirement**
**Summary of AG Recommendations**
**For the Test Year Ended June 30, 2026**
**($ Millions)**

| | Amount Before Gross-Up | Adjusted B/D and KPSC Maint. Fee Gross-up | Amount After Gross-Up | AG Witness |
|---|---|---|---|---|
| **Base Rate Increase Requested by Company** | | | 70.008 | |
| **Effects on Base Rate Increase of AG Rate Base Recommendations** | | | | |
| Correct Error in Cash Working Capital Due to Expense Synchronization | | | (0.005) | Futral |
| Remove Deferrred Rate Case Expense, Net of ADIT | | | (0.092) | Futral |
| Subtract Vendor Supplied Portion of Construction Payables | | | (1.752) | Kollen |
| Reduce Cash Working Capital to Reflect Revenue Collection Lag Days for 2024 | | | (0.289) | Futral |
| Reduce Cash Working Capital to Remove Non-Cash Coal, Lime, and Prepaid Expenses | | | (0.512) | Kollen |
| Reduce Cash Working Capital to Include Long Term Debt Interest Expense | | | (0.293) | Kollen |
| Reduce Cash Working Capital to Reflect Sale of Receivables in Collection Lag Days | | | (1.621) | Kollen |
| Remove CAMT Deferred Tax Asset | | | (1.169) | Kollen |
| Reflect Changes in A/D and ADIT Due to Lower Depr. Expense - 2041 East Bend Retirement | | | 0.134 | Kollen |
| Reflect Changes in A/D and ADIT Due to Lower Depr. Expense - No Terminal Net Salvage | | | 0.137 | Kollen |
| **Effects on Base Rate Increase of AG Operating Income Recommendations** | | | | |
| Reduce Uncollectible Expense by Utilizing More Current 2024 Electric-Only Historic Data | (2.105) | 1.00156 | (2.109) | Futral |
| Correct Error to Reflect Amortization of DEBS EDIT | (0.016) | 1.00613 | (0.017) | Futral |
| Increase Revenues by Using Unbilled Revenues | (0.331) | 1.00613 | (0.333) | Kollen |
| Reduce Projection of PJM NITS Transmission Fees Expense | (2.278) | 1.00613 | (2.292) | Futral |
| Remove 50% of Directors and Officers Insurance Expense to Share with Shareholders | (0.092) | 1.00613 | (0.092) | Futral |
| Remove 50% of Board of Directors Compensation Expense to Share with Shareholders | (0.012) | 1.00613 | (0.012) | Futral |
| Remove 50% of Investor Relations Expense to Share with Shareholders | (0.029) | 1.00613 | (0.030) | Futral |
| Reject Proposed Socialization of Credit Card Processsing Fees | (0.319) | 1.00613 | (0.321) | Kollen |
| Reduce Depreciation Expense to Reflect 2041 Retirement Date for East Bend | (5.373) | 1.00613 | (5.406) | Kollen |
| Reduce Depreciation Expense to Remove Terminal Net Salvage Component of Depreciation Rates | (5.469) | 1.00613 | (5.502) | Kollen |
| **Effects on Base Rate Increase of AG Rate of Return Recommendations** | | | | |
| Reduce Return on Equity from 10.85% to 9.65% | | | (10.341) | Baudino |
| **Total AG Adjustments to DEK Request** | | | (31.916) | |
| **Maximum Base Rate Increase After AG Adjustments** | | | 38.093 | |

In the subsequent sections of my testimony, I address the issues identified with my name in Table 1 in greater detail. I also summarize the effects of AG witness Mr. Lane Kollen's recommendations to modify the base rate revenue requirement. Finally, I quantify the effects of AG witness Mr. Richard A. Baudino's return on equity rate of return recommendation on the base rate revenue requirement. I note that the costs of capital, including the return on equity, authorized in this proceeding will also have an effect on the Company's Environmental Surcharge Mechanism ("ESM") rider in future ESM filings.

Table 1 lists the AG witness responsible for each recommended adjustment. Some of the adjustments recommended by the AG could also have a minimal effect on the computation of cash working capital included in rate base. I have not attempted to synchronize the balance of cash working capital related to those adjustments. It can be synchronized after all other adjustments to the applicable expenses are determined as a result of the adjudication in this proceeding.

## II. DUKE KENTUCKY ERRORS AND CORRECTIONS

**Q. Did Duke Kentucky make errors in its application?**

A. Yes. The Company made two small errors in its application in the calculation of its proforma adjustment schedules. When responding to discovery, Duke Kentucky acknowledged that it had made at least two errors in the quantifications of certain proforma adjustments and it provided the necessary corrected schedules in order to adjust the revenue requirement. I have provided below in Table 2 a list of the errors acknowledged by the Company along with the effects on the Company's requested revenue requirement. The corrections I compute sum to a revenue requirement reduction of $0.022 million. I will describe each of the identified errors in the discussion below.

**Table 2**
**Duke Energy Kentucky, Inc.**
**Company Acknowledged Errors and Effects on Revenue Requirement**
**($ Millions)**

| **Description** | **Data Response(s)** | **Grossed-Up Return on Rate Base Reduction** | **Grossed-Up Expense Reduction** | **Total Revenue Requirement Reduction** |
|---|---|---|---|---|
| Synchronization of Expenses in CWC | AG-DR-01-054 | (0.005) | - | (0.005) |
| Amortization of DEBS EDIT | AG-DR-01-116 | - | (0.017) | (0.017) |
| Total | | | | (0.022) |

**Q. Can you describe the first error in the Company's application that Duke Kentucky has already acknowledged?**

A. Yes. Duke Kentucky included $4.508 million of cash working capital ("CWC") in rate base in its application based on the results of a lead/lag study performed on its behalf.[4] Duke Kentucky was asked in discovery to prove that the test year expenses used in the CWC lead/lag study matched the expenses reflected elsewhere in the Company's determination of the revenue requirement and to provide an updated CWC calculation if not.[5] The Company provided the information and stated the following, in part, in the narrative portion of the response: [6]

> While responding to this request, it was determined that the Miscellaneous Expense Adjustment and the Federal and State Income Taxes are not synchronized with the as-filed amounts provided elsewhere in the application schedules.

[4] Application at Schedules B-1 and B-5; Direct Testimony of Michael J. Adams ("Adams Testimony"), Attachment MJA-2.
[5] Duke Kentucky's response to AG-DR-01-054. I have attached a copy of the narrative portion of this response as my Exhibit RAF-2.
[6] Duke Kentucky's response to AG-DR-01-054(b). See Exhibit RAF-2.

The Cash Working Capital analysis has been updated, and a revised calculation can be found in AG-DR-01-054 Attachment. Further, the overall impact of the updates to the Company's Forecasted Period Cash Working Capital requirement has been quantified in the table below.

| | |
|---|---|
| Forecasted Period CWC Requirement - As Filed | $4,507,797 |
| Update Miscellaneous Expenses | ($14,985) |
| Update Federal and State Income Taxes | ($36,193) |
| Updated CWC Requirement | $4,456,619 |

Duke Kentucky's response to this discovery indicated that the CWC included in rate base should be reduced by $0.051 million to properly synchronize the lead/lag study level of expenses with the level of expenses included elsewhere in its determination of the revenue requirement.

**Q. What is your recommendation?**

A. I recommend that the Commission reduce rate base by $0.051 million and the base revenue requirement and base rate increase by $0.005 million to correct for the error identified by the Company.

**Q. Can you describe the second error you reflect in Table 2 regarding the amortization of Duke Energy Business Services LLC ("DEBS") Excess Accumulated Deferred Income Taxes ("EDIT") as a result of the Tax Cut and Jobs Act?**

A. Yes. The Commission's Order in Case No. 2019-00271 stated that the $0.214 million of DEBS EDIT previously allocated to Duke Kentucky electric should be amortized over a five-year period and returned to customers through a revenue reduction.[7] The

[7] Case No. 2019-00271, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Apr. 27, 2020), Order at 23.

rates from that Order became effective on May 1, 2020, resulting in a remaining balance of $0.082 million as of June 30, 2023 just prior to the start of the forecast test year in the last rate case, Case No. 2022-00372.[8] The Company requested and the Commission authorized a five-year amortization of the $0.082 million remaining balance resulting in an amortized reduction of income tax expense of $0.016 million per year.[9] When asked about how the remaining DEBS EDIT amortization was reflected in the application, the Company responded that it had inadvertently not included it in the revenue requirement.[10]

**Q. Did the Company provide the amount of amortization that should be included in the revenue requirement?**

A. Yes. The Company stated in discovery that the amortization amount of $0.016 million should have been included as a reduction in the revenue requirement and that the balance should be fully amortized by approximately the end of 2027.[11]

**Q. What is your recommendation?**

A. I recommend that the Commission reduce the base revenue requirement and base rate increase by $0.017 million to properly reflect the amortization of the unamortized DEBS EDIT balance. This effect includes the effect of the $0.016 million reduction in expense along with the gross up for the effects of uncollectible expense and Commission assessment fees.

[8] Case No. 2022-00372, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC Oct. 12, 2023), Order at 15.
[9] *Id.*
[10] Duke Kentucky's response to AG-DR-01-116, a copy of which is attached as my Exhibit RAF-3.
[11] *Id.*

## III. RATE BASE ISSUES

### A. Remove Regulatory Asset for Deferred Rate Case Expenses

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

A. The Company included $1.231 million in deferred rate case expenses in rate base.[12] $0.734 million of this amount relates to the instant case, while $0.058 million relates to the remaining unamortized deferred balance associated with Case No. 2019-00271 and $0.439 million relates to the remaining unamortized deferred balance associated with Case No. 2022-00372. The Company also included an accumulated deferred income tax ("ADIT") offset of $0.307 million as a subtraction to rate base related to the unamortized rate case costs.[13] The ADIT amount was calculated using the 24.9251% effective tax rate included by the Company in its application.[14]

**Q. Should the Commission include the regulatory asset for deferred rate case expenses in rate base in this proceeding?**

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[12] Refer to WPB-1.1a, which is a supporting workpaper for Schedule B-1, found on tab WPB-1 on Duke Kentucky's response to Staff's First Request for Information ("Staff's First Request"), Item 54, Attachment_KPSC_Electric_SFRs-2024 at line numbers 11,13, and 15. These line numbers reflect a combined total of $1.231 million for the total 13-month average deferred rate case costs in rate base. That amount includes $0.734 million average deferred rate case costs for the instant Case No. 2024-00354, $0.058 million in average deferred rate case costs for Case No. 2019-00271, and $0.439 million in average deferred rate case costs for Case No. 2022-00372.

[13] Duke Kentucky's response to AG-DR-02-061, a copy of which is attached as my Exhibit RAF-4. I compute the ADIT effects of the temporary differences reflected in this response based on the amounts of applicable ADIT included in the as-filed revenue requirement. See the electronic workpapers filed with my Direct Testimony.

[14] I show the calculation of the 24.9251% combined effective income tax rate in my electronic workpapers filed along with my testimony, which are based on the percentages contained in the Company's application at Schedule H.

A. No. The rate case expenses were and will be incurred to benefit Duke Kentucky's ultimate parent company, Duke Energy Corporation ("Duke Energy"), and its shareholders. They were and will not be incurred to benefit the Company's customers.

**Q. Has the Commission recently addressed this issue in other recent base rate case proceedings, including that of Duke Kentucky?**

A. Yes. In Case No. 2019-00271, the Commission rejected Duke Kentucky's request to include regulatory assets for deferred rate case expenses in rate base.[15] In its Order, the Commission stated: "The Commission agrees that rate case expense regulatory assets should not be included in rate base, as that would allow a return on the unamortized balance of the expense. The Commission has historically excluded this item from rate base to share the cost of rate proceedings between the stockholders and ratepayers."[16] The same justification was given by the Commission when it rejected Atmos Energy Corporation's request in Case No. 2021-00214 to include a regulatory asset for deferred rate case expenses in rate base.[17] The Commission confirmed its position yet again in a recent Water Service Corporation of Kentucky base rate proceeding in Case No. 2022-00147.[18]

**Q. Did the Company seek to include regulatory assets for deferred rate case expenses in its last base rate proceeding, Case No. 2022-00372?**

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[15] *See* Case No. 2019-00271, *Electronic Application of Duke Energy Kentucky, Inc. for 1) An Adjustment of the Electric Rates; 2) Approval of New Tariffs; 3) Approval of Accounting Practices to Establish Regulatory Assets and Liabilities; and 4) All Other Required Approvals and Relief* (Ky. PSC April 27, 2020), Order at 7-8.

[16] *Id.*

[17] *See* Case No. 2021-00214, *Electronic Application of Atmos Energy Corporation for An Adjustment of Rates*, (Ky. PSC May 19, 2022), Order at 17-18.

[18] *See* Case No. 2022-00147, *Electronic Application of Water Service Corporation of Kentucky for General Adjustment in Existing Rates and a Certificate of Public Convenience and Necessity to Deploy Advanced Metering Infrastructure*, (Ky. PSC April 12, 2023), Order at 13-14.

A. No. In fact, the Company included no regulatory assets or liabilities in rate base on Schedule B-1 in its application in that proceeding.

**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 the Company's customers?**

A. Yes. The revenue requirement cost of the regulatory asset declines each year as it is amortized and as the net rate base amount declines. However, the Company's customers never benefit from this annual cost reduction until base rates are reset at some future date. The Company retains the savings from the declining costs and the Company's customers never benefit from these reductions because the base revenue recovery is never trued-up.

**Q. What is your recommendation?**

A. I recommend that the Commission allocate the *return on* the regulatory asset for the deferred rate case expenses to Duke Energy and its shareholders, but allocate the amortization expense to the Company's customers as a form of sharing between Duke Energy shareholders and the Company's customers.

This recommendation is necessary to ensure that the costs are equitably shared between the Company's ultimate shareholders and customers. Over a five-year amortization period, this will allocate approximately 20% of the total revenue requirement related to the instant proceeding to Duke Energy and approximately 80% to the Company's customers based on the as-filed revenue requirement.

In addition, this recommendation is necessary to ensure that the Company does not obtain excessive recovery of these costs as the regulatory asset is amortized and the underlying cost curve declines, ultimately to $0, without adjustment to the base revenues to reflect the declines in those costs.

Finally, this recommendation is consistent with the Commission's recent decisions in Case Nos. 2019-00271, 2021-00214, and 2022-00372 as well as other proceedings.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $0.924 million in rate base and a reduction of $0.092 million in the base revenue requirement and base rate increase. These amounts are computed net of the effects of ADIT associated with the rate case expense deferral amounts that the Company had included in its filed revenue requirement.

## B. Reduce CWC to Reflect Revenue Collection Lag Days on 2024 Parameters

**Q. Describe the collection lag days computed as part of the revenue lag used in the Company's lead/lag study.**

A. As described above, Duke Kentucky included $4.508 million of CWC in rate base in its application based on the results of a lead/lag study performed on its behalf.[19] As also described above, that amount was reduced to $4.457 million to correct a small synchronization error. This lead/lag study utilized per books revenue and expense data for the twelve months ended December 31, 2023.[20] One of the starting components of a lead/lag study is the determination of the number of revenue lag days. The Company's study determined this amount to be 45.52 days.[21] The revenue lag days in

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[19] Application at Schedules B-1 and B-5; Adams Testimony, Attachment MJA-2.
[20] Adams Testimony at 5.
[21] *Id* at 7-8.

the Company's study are made up of service lag, billing lag, collection lag, and payment processing lag components.[22] While the service lag and billing lag components seemed reasonable, the collection lag and the payment processing lag in the application was computed to be a combined 27.48 days,[23] which seemed high. The collection/payment processing lag represents the average number of days between the time customers are billed and the receivables posted and the time billings are collected. Duke Kentucky provided its computation of the 26.66 collection lag days in response to discovery as part of its electronic workpapers.[24] This collection lag day computation determines a weighted average number of days associated with the accounts receivable in all of its individual aging buckets over all the months in 2023 and sums those weighted days to derive an average weighted collection days amount of 26.66 days. The Company confirmed in response to discovery that the receivables balances data in total and separated by aging bucket that it used represented a combination of its electric and gas divisions.[25]

**Q. Did the Company separate its receivables data between its electric division and gas division?**

A. No. According to the response to discovery, the Company could not separate the data between the divisions because "the billing system does not maintain the Accounts Receivable Aging Reports by service."[26]

**Q. Is there a major consideration that should be made in terms of the level of electric**

[22] *Id.*
[23] *Id.* The Collection lag was 26.66 days and the payment processing lag was 0.82 days.
[24] Responses to AG-DR-01-053 and AG-DR-01-054. I have attached for convenience a copy of the collection lag day computation only from the lead/lag study electronic workpapers as my Exhibit RAF-5.
[25] Response to AG-DR-02-054, a copy of which I have attached as my Exhibit RAF-6.
[26] *Id.*

**and gas receivables balances during 2023 used to determine the number of appropriate revenue collection days?**

A. Yes. Natural gas prices soared in 2022 to levels not seen since 2008. Henry Hub natural gas prices started increasing in 2021 from a long-standing level of around $2-$3 per Million Metric British Thermal Units ("mmBtu") to around $4-5 per mmBtu.[27] Prices during 2022 increased even further, rising to over $8 per mmBtu in August that year and ended the year at over $5 per mmBtu.[28] Prices decreased substantially starting in 2023 to levels in the $2-$3 per mmBtu once again, similar to prices experienced in years prior to 2021.[29] Market prices have remained lower since the start of 2023.[30] While this commodity price increase affected owned generation and market prices for both the electric and gas divisions, the gas division would have been more impacted. That is because the electric division relies on a variety of fuel sources for its generation and upon market purchases, while the gas division is totally dependent on the pricing for natural gas that it purchases. Gas customer bills increased substantially during this period due to the higher commodity price of gas leading to higher receivable balances in later months.

**Q. Did the Company provide the data needed to recompute the number of collection lag days using only 2024 receivables data?**

A. Yes. The Company provided in response to discovery a recomputed number of collection days of 24.83 using a combination of 2023 and 2024 total company

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[27] Henry Hub Natural Gas Spot Price (Dollars per Million Btu).
[28] *Id.*
[29] *Id.*
[30] *Id.*

receivables data.[31] While the intent of the discovery was to obtain a calculation using just 2024 data, the Company combined the 2023 data with the 2024 data. Removing the 2023 receivables data from the Company's new calculation yields a number of collection days of only 23.15 applicable only to 2024.[32]

**Q. What is your recommendation?**

A. I recommend that the Commission require that the collection lag days determination be based upon the 2024 data only. The 2023 combined electric and gas division receivables data relied upon by the Company in the lead/lag study was highly impacted by the short-term spike in natural gas commodity prices prior to the start of 2023. The 2024 data is a more reasonable and recurring level of historic collection data that should be used to set the level of collection lag days. I recommend that the Commission utilize the 2024-only collection lag days of 23.15 days instead of the as-filed 2023-only collection lag days of 26.66. My recommendation decreases the combined collection and payment processing days to 23.97 days instead of the as-filed 27.48 days. This lowers the overall revenue lags days from the as-filed 45.52 days to 42.01 days. This recommendation is made before consideration of Mr. Kollen's separate recommendation related to the cessation of the Company's sale of its receivables to Cinergy Receivables Corporation.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $2.894 million in rate base and a reduction of $0.289 million in the base revenue requirement and base rate increase.

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[31] Duke Kentucky's response to AG-DR-02-054. See Exhibit RAF-6.

[32] My calculation of the 23.15 collection days is included in my electronic workpapers filed along with my testimony. The combined collection days and payment processing days now sum to 23.97 days.

## IV. OPERATING INCOME ISSUES

**A. Reduce Uncollectible Expense**

**Q. Describe the Company's request to include uncollectible expense in the base revenue requirement.**

A. The Company proposes to include $4.152 million in uncollectible expense in the base revenue requirement.[33] It calculated this amount by applying the total projected revenue subject to the uncollectible expense of $450.814 million[34] by a historical uncollectible expense factor of 0.921%, which was computed based on 2023 total company (electric and gas divisions combined) uncollectible net charge-off experience. This amount is nearly double the amount of uncollectible expense in account 904 in the base period of $2.246 million and the amount of $2.367 forecast in the test period prior to the addition of the proforma adjustment of $1.785 million that increased the forecast test period amount up to $4.152 million. [35]

**Q. How was the 0.921% uncollectible expense factor determined by the Company?**

A. The 0.921% uncollectible expense factor was computed by the Company by dividing actual net receivable charge-offs by the total applicable revenues during 2023, both of

[33] Application at Schedule D-2.21 and supporting workpaper WPD-2.21a at cells J35 through P59 tab WPD-2.21a on Duke Kentucky's response to Staff's First Request, Item 54, Attachment_KPSC_Electric_SFRs-2024.

[34] This total revenue amount includes the proposed base revenues, projected fuel revenues, less projected interdepartmental revenues.

[35] Application at Schedule D-2.21 and supporting workpaper WPD-2.21a on Duke Kentucky's response to Staff's First Request, Item 54, Attachment_KPSC_Electric_SFRs-2024. Also, tabs SCH_C2.1 – Base Period and SCH_C2.1 – Forecasted Period applicable to account 904 on Duke Kentucky's response to Staff's First Request, Item 54, Attachment_KPSC_Electric_SFRs-2024.

which were applicable to the combined electric and gas divisions of Duke Kentucky.[36] According to the response to discovery, the Company had to rely upon total company, combined electric and gas divisions, activity in 2023 because the Company sold its receivables to Cinergy Receivables Corporation throughout 2023 and did not track the data separately.[37] According to the Company, it now owns the receivables and needs to track the charge-offs separately between the electric and gas divisions.[38] Thus, the separate electric and gas division charge-off data became available starting with 2024.

**Q. Is the computed 0.921% uncollectible expense factor reasonable in light of the most current and specific electric-only division data available?**

A. No. The 0.921% factor is excessive and should be reduced to a level that is considered more reasonable and recurring. Table 3 below provides the combined total company electric and gas net charge-off percentages for all months and in sum for 2022, 2023, and 2024 as well as the electric-only percentages applicable to only 2024.[39]

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[36] Duke Kentucky's response to AG-DR-01-057, a copy of which is attached as my Exhibit RAF-7.
[37] *Id.*
[38] *Id.*
[39] *Id.*

**Table 3**
**Duke Energy Kentucky, Inc.**
**Summary of Uncollectible Expense Factors**
**Net Charge-Offs as a Percentage of Revenue**

| | Total Company | | | Electric Only |
|---|---|---|---|---|
| **Month** | **2022** | **2023** | **2024** | **2024** |
| Jan | 0.184% | 0.934% | 0.491% | 0.405% |
| Feb | 0.150% | 1.005% | 0.356% | 0.273% |
| Mar | 0.475% | 1.091% | 0.411% | 0.294% |
| Apr | -0.076% | 2.232% | 1.015% | 0.555% |
| May | -0.070% | 1.470% | 1.096% | 0.656% |
| Jun | -0.143% | 0.869% | 0.603% | 0.437% |
| Jul | 0.365% | 1.022% | 0.501% | 0.319% |
| Aug | 0.548% | 0.659% | 0.585% | 0.345% |
| Sep | 0.687% | 0.405% | 0.830% | 0.564% |
| Oct | 1.759% | 0.897% | 0.794% | 0.685% |
| Nov | 1.230% | 0.783% | 0.507% | 0.489% |
| Dec | 0.613% | 0.557% | 0.619% | 0.581% |
| Total Year | 0.448% | 0.921% | 0.636% | 0.454% |

Source: Response to AG-DR-01-057 Attachment 1

The data, based on actual experience, shows that the 2024 electric-only uncollectible expense factor was only 0.454%, which is less than half of the factor of 0.921% used in the Company's proforma adjustment determination. The data also shows that the overall factor of 0.921% for 2023 appears to be an outlier compared to the annual factors for the other years. The data further shows that the total company expense factor started to grow considerably near the end of 2022 and remained considerably higher than normal through around July of 2023 before starting to decrease. Finally, the data shows that the 2024 monthly combined electric and gas division factors were consistently higher than the electric-only factors for same periods.

**Q. Was the spike in natural gas prices that you mentioned above a major reason why the expense factor increased so much for the total company starting in late 2022?**

A. Yes. Customer bills, especially for gas customers, increased substantially during this period due to the higher commodity price of gas leading to higher charge-offs of receivable balances in later months. That is a big factor why the total company uncollectible expense factor increased substantially during the latter part of 2022 and through the middle of 2023. The total company uncollectible expense factor returned to an annual level of only 0.636% during 2024 at the same time the electric-only factor was only 0.454%.

**Q. What is your recommendation?**

A. Now that the electric and gas division uncollectible data can be separated, there is no reason to rely upon a combined total company expense factor to determine the projected uncollectible expense. In addition, the 2023 combined electric and gas division data relied upon by the Company in its proforma adjustment was highly impacted by the short-term spike in natural gas commodity prices prior to the start of 2023. The separated 2024 data is a more reasonable and recurring level to be used to set the projected level of future expense. I recommend that the Commission utilize the 2024 electric-only uncollectible expense factor of 0.454% to compute the Company's projected uncollectible expense for its electric division.

**Q. What is the effect of your recommendation?**

A. The effect is a $2.105 million reduction in the amount of uncollectible expense in the test year and a reduction of $2.109 million reduction in the base revenue requirement and base rate increase after the gross-up for Commission assessment fees. This amount was computed based on multiplying the as-filed projected total revenues by the uncollectible expense factor of 0.454% to equal $2.047 million in uncollectible expenses. This amount is $2.105 million less than the $4.152 million included in the Company's application. I intentionally computed this as the first adjustment to the Company's request. The quantification impacts of all other adjustments are affected by the gross-up factor applied to them, consisting of a combination of the uncollectible expense factor and the Commission assessment fees factor. I have adjusted the gross-up factor to incorporate the more appropriate uncollectible expense factor of 0.454% in order to reflect the revenue requirement impacts of all the other AG's recommended adjustments to the Company's request.

**B. <u>Reduce Projection of PJM NITS Transmission Fees</u>**

**Q. Describe the level of transmission expenses in account 565 (Transmission of Electricity by Others) included in the revenue requirement in this proceeding.**

A. The Company projected a large increase in the level of account 565 expenses in the projected test year compared to the base year. Total expenses in this account were projected to be $29.352 million in the test period compared to only $24.452 in the base period, an increase of over 20.0%.[40] The majority of the expenses in this account

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[40] Application at Schedule C-2.1 at page 3 of 14 for the base period amount and at page 10 of 14, lines 10-11, for the forecast period amount.

relate to PJM Interconnection LLC ("PJM") Network Integrated Transmission Service ("NITS") fees. The Company projected the PJM NITS fees to be $28.795 million in the test period and it projected another $0.557 million in expenses for the accretion of Midcontinent Independent System Operator ("MISO") Transmission Expansion Plan ("MTEP") obligations.[41] The MTEP expenses have been flat over the last several years and are expected to remain flat at least through the projected test period.[42] Thus, the only projected increase in account 565 is related to the PJM NITS fees.

**Q. How did Duke Kentucky project the PJM NITS fees for the test period?**

A. Duke Kentucky compared the PJM NITS fees actual expense for the first six months of 2024 with the PJM NITS fees actual expense for the first six months of 2023 to determine an escalation rate of 11.7% to apply to the entirety of the 2023 expense in order to project all future years, including the test period.[43] The 2023 actual expense amount was $21.808 million.[44] That amount was escalated by 11.7% to project the 2024 level of PJM NITS fees to be $24.359 million.[45] That amount was escalated by 11.7% to project the 2025 level of PJM NITS fees to be $27.209 million and escalated again by 11.7% to project the 2026 level of PJM NITS fees to be $30.392 million.[46] The Company projected PJM NITS fees for the test period ending June 30, 2026 to be $28.795 million, derived by combining half of the 2025 amount with half of the 2026 amount along with a small reconciling amount of $0.006 million identified by the

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[41] Application at Schedule C-2.1 at page 10 of 14, lines 10-11. Refer also to Duke Kentucky's response to AG-DR-01-095(b). I have attached the entire response to AG-DR-01-095 as my Exhibit RAF-8.

[42] Duke Kentucky's response to AG-DR-01-095(b). See Exhibit RAF-8.

[43] Duke Kentucky's response to AG-DR-01-095, including the Attachment electronic calculation. See Exhibit RAF-8.

[44] *Id.*

[45] *Id.*

[46] *Id.*

Company in response to discovery.[47]

**Q. Is the Company's escalation methodology appropriate?**

A. No. The Company's determination of the 11.7% escalation rate is based on the use of only six months of data. The Company should have used data for at least an entire year to derive this escalation percentage to alleviate concerns of fluctuating expense levels applicable to only portions of a year. Such a concern is why most rate base components are based on the monthly average levels of amounts over a full thirteen-month period, not just a six-month period.

**Q. Can you provide the actual expense amounts for the PJM NITS fees over the last several years?**

A. Yes. Table 4 below shows the total amount of expenses for the years 2020 through 2024 in account 565, broken out between the $0.557 million per year in MTEP obligations and the PJM NITS fees.

[47] *Id.*

**Table 4**
**Duke Energy Kentucky, Inc.**
**Breakdown of Account 565**
**$**

| Year | Total Account 565 | Less: MTEP | PJM NITS Fees | PJM NITS Percentage Increase |
|---|---|---|---|---|
| 2020 | $19,283,242 | $ (557,000) | $ 18,726,242 | |
| 2021 | $19,455,367 | $ (557,000) | $ 18,898,367 | 0.9% |
| 2022 | $21,126,946 | $ (557,000) | $ 20,569,946 | 8.8% |
| 2023 | $22,364,509 | $ (557,000) | $ 21,807,509 | 6.0% |
| 2024 | $24,132,590 | $ (557,000) | $ 23,575,590 | 8.1% |
| | | 4-YR Average | | 6.0% |
| | | 3-YR Average | | 7.6% |

Source: Response to AG-DR-01-095

The actual expense data shows that the PJM NITS fees in 2024 were $23.576 million compared to $21.808 million in 2023, representing an increase of only 8.1%. This increase percentage is considerably lower than the 11.7% per year escalations used in the Company's projections. The average escalation percentage over the four years is actually only 6.0%, even though that percentage was driven lower by the small increase in PJM NITS fees from 2020 to 2021. The average escalation percentage over the last three years is only 7.7%. The data also shows that the actual 2024 PJM NITS fees of $23.576 million was substantially lower than the $24.359 million that the Company projected for calendar year 2024 using its six-month determined escalation percentage methodology.

**Q. What is your recommendation?**

A. I recommend that the Commission base the projected PJM NITS fees in the projected test period on a starting point of $23.576 million for 2024, the calendar year 2024 actual fees, and escalate that amount by 8.1% each year to determine the 2025 and 2026 amounts used to determine the projected test period amount. The 8.1% is the latest actual annually based escalation percentage, 2024 actual versus 2023 actual, for the PJM NITS fees. That percentage is very close to the average escalation increase over the last three years of 7.7% and represents a much more appropriate proxy than the one utilized by the Company. The escalated 2025 calendar year amount using the 8.1% escalation percentage would be $25.485 million ($23.576 million actual x 1.081) and the 2026 calendar year amount using the 8.1% escalation percentage would be $27.549 million ($25.485 million projected x 1.081). Half of the 2025 amount combined with half of the 2026 amount yields a recommended projected test period amount of PJM NITS fees of $26.517 million, which is $2.278 million less than the $28.795 million projected by the Company.

**Q. What is the effect of your recommendation?**

A. The effect is a reduction of $2.278 million in PJM NITS fees in account 565 and a reduction of $2.292 million in the claimed base revenue requirement and base rate increase after the gross up for the effects of uncollectible expense and Commission assessment fees.

**C. <u>50% Sharing of Corporate Expenses</u>**

**Q. Can you describe three types of corporate related expenses that Duke Kentucky included in the revenue requirement in this proceeding?**

A. Yes. Duke Kentucky is a subsidiary of its parent company, Duke Energy. Duke Energy incurs certain expenses related to the directors and officers of the corporation and other expenses related to communications with its investors. These expenses are allocated to each of the Duke Energy subsidiaries, including Duke Kentucky, utilizing a three factor allocation formula described in the Company's Cost Allocation Manual.

Duke Energy projects that it will incur Director's & Officer's ("D&O") insurance expense during the test year and that it will allocate $0.183 million of that amount to Duke Kentucky's electric division as part of O&M expense.[48] The Company included this amount as part of the overall revenue requirement in this proceeding. D&O insurance is designed to protect the individual directors and officers of an organization from personal losses if they are sued as a result of their service and decisions made while serving in those roles. It can also help to defray legal and other costs incurred by an organization related to any such suits. Finally, D&O insurance can act as an ultimate protection to shareholders, giving them protection from any negligent acts committed by an organization's directors and officers.

Duke Energy projects that it will incur Board of Directors ("BOD") compensation expense during the test year and that it will allocate $0.023 million of that amount to Duke Kentucky's electric division as part of O&M expense.[49] The

[48] Duke Kentucky's response to AG-DR-01-128, a copy of which is attached as my Exhibit RAF-9.
[49] Duke Kentucky's response to AG-DR-01-130, a copy of which is attached as my Exhibit RAF-10.

Company included this amount as part of the overall revenue requirement in this proceeding.

Duke Energy projects that it will incur investor relations expense during the test year and that it will allocate $0.059 million of that amount to Duke Kentucky's electric division as part of O&M expense.[50] The Company included this amount as part of the overall revenue requirement in this proceeding. Like many other large publicly held organizations, Duke Energy maintains an investor relations unit to interact with current and potential investors. The Duke Energy website details the communications supplied to investors.[51] These include such things as news releases, investor presentations, regulatory filings with the U.S. Securities and Exchange Commission, analyst reports, and other statistical and reporting information.

**Q. Should there be a sharing of all three kinds of corporate expenses between ratepayers and shareholders?**

A. Yes. Ratepayers should not be expected to be held responsible for all of these costs, especially since the majority of the benefits arising from these kinds of expenses are retained by shareholders.

**Q. What do you recommend?**

A. I recommend a 50/50 sharing of the D&O insurance, BOD compensation, and investor relations expenses between ratepayers and shareholders to align costs with derived benefits. Thus, I recommend a 50% reduction in each expense included in the revenue requirement for Duke Kentucky. This amounts to a reduction of D&O insurance

[50] Duke Kentucky's response to AG-DR-01-129, a copy of which is attached as my Exhibit RAF-11.
[51] Duke Energy Corporation - Investor Relations

expense of $0.092 million, a reduction of BOD compensation expense of $0.012 million and a reduction of investor relations expense of $0.029 million, all of which should be grossed up for the effects of uncollectible expense and Commission assessment fees. I reflected those gross up adjustments in Table 1 above.

## IV. COST OF CAPITAL ISSUES

### A. Effect of Lower Return on Common Equity

**Q. Have you quantified the effect on the Company's revenue requirement of the return on equity recommendation of 9.65% sponsored by AG witness Mr. Richard Baudino?**

A. Yes. The effect is a reduction of $10.341 million in the base revenue requirement. There will be an additional effect on the ESM revenue requirement in future ESM filings, 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 $0.862 million on the base revenue requirement.

### B. AG Recommended Cost of Capital

**Q. Can you provide a summary table showing the cost of capital components as originally filed by the Company and with Mr. Baudino's return on common equity recommendation?**

A. Yes. See the Table 6 below.

**Table 5**
**Duke Energy Kentucky, Inc.**
**Cost of Capital**
**KPSC Case No. 2024-00354**

**DEK Cost of Capital Per Filing**

| | Capital Ratio | Component Costs | Weighted Avg Cost | Grossed-Up WACC |
|---|---|---|---|---|
| Short Term Debt | 4.79% | 3.20% | 0.15% | 0.15% |
| Long Term Debt | 42.48% | 4.93% | 2.09% | 2.12% |
| Common Equity | 52.73% | 10.85% | 5.72% | 7.70% |
| Total Capital | 100.00% | | 7.97% | 9.97% |

**DEK Cost of Capital Recommended by AG**

| | Capital Ratio | Component Costs | Weighted Avg Cost | Grossed-Up WACC |
|---|---|---|---|---|
| Short Term Debt | 4.79% | 3.20% | 0.15% | 0.15% |
| Long Term Debt | 42.48% | 4.93% | 2.09% | 2.11% |
| Common Equity | 52.73% | 9.65% | 5.09% | 6.82% |
| Total Capital | 100.00% | | 7.34% | 9.08% |

**Q. Does this complete your testimony?**

A. Yes.

**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; (3) APPROVAL OF ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (4) ALL OTHER REQUIRED APPROVALS AND RELIEF** | ) | **CASE NO. 2024-00354** |

**EXHIBITS**

**OF**

**RANDY A. FUTRAL**

**ON BEHALF OF THE**

**OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY**

**J. KENNEDY AND ASSOCIATES, INC.**
**ROSWELL, GEORGIA**

**MARCH 5, 2025**

**EXHIBIT RAF-1**

**RESUME OF RANDY A. FUTRAL – DIRECTOR OF CONSULTING**

## EDUCATION

**Mississippi State University, BBS in Business Administration**
Accounting

## EXPERIENCE

**J. Kennedy and Associates, Inc.** **2003 - Present**
**Director of Consulting**

Responsible for utility revenue requirements analysis, affiliate transaction auditing and analysis, fuel adjustment clause auditing and research involving tax and public reporting matters. Clients served include the Georgia Public Service Commission ("GPSC") Staff, the Louisiana Public Service Commission ("LPSC") and its Staff, the Florida Office of Public Counsel ("OPC"), the Office of the Attorney General of the Commonwealth of Kentucky ("KY AG"), the South Carolina Office of Regulatory Staff ("ORS"), the Houston Council for Health and Education, the Gulf Coast Coalition of Cities, Cities Served by Texas Gas Service Company, the Alliance for Valley Healthcare, the Ohio Energy Group, Inc. ("OEG"), the Kentucky Industrial Utility Customers ("KIUC"), the Municipalities of Alda, Grand Island, Kearney and North Platte, Nebraska, the City of Clinton, and the Wisconsin Industrial Energy Group, Inc.

Direct and Responsive Testimonies filed on behalf of Louisiana Public Service Commission or its Staff:
LPSC Docket No. U-23327 Southwestern Electric Power Company, Revenue Requirement Review, October 2004.
LPSC Docket No. U-21453, U-20925, U-22092 Entergy Gulf States, Inc., Jurisdictional Separation Plan, March 2006.
LPSC Docket No. U-25116 Entergy Louisiana, Inc., 2002-2004 Audit of Fuel Adjustment Clause, April 2006.
LPSC Docket No. U-23327 Southwestern Electric Power Company, Revenue Requirement Review, July 2006.
LPSC Docket No. U-21453, U-20925, U-22092 Entergy Gulf States, Inc., Jurisdictional Separation Plan, August 2006.
FERC Docket No. ER07-682 Entergy Services, Inc., Company's Section 205 Changes to Rough Production Cost Equalization Computation, November 2007.

FERC Docket No. ER07-956 Entergy Services, Inc., Company's 2007 Filing to be in Compliance with FERC Opinions' 480and 480-A, March 2008.
FERC Docket No. ER08-51 Entergy Services, Inc., LPSC Section 206 Filing Related to Spindletop Regulatory Asset in Rough Production Cost Equalization Computation, November 2008.
FERC Docket No. ER08-1056 Entergy Services, Inc., Company's 2008 Filing to be in Compliance with FERC Opinions' 480and 480-A, January 2009.
LPSC Docket No. U-31066 Dixie Electric Membership Corporation, Company's Application to Implement a Storm Recovery Rate Rider, September 2009.
LPSC Docket No. U-30893 Dixie Electric Membership Corporation, Company's Application to Implement a Formula Rate Plan, September 2009.
FERC Docket No. EL09-61 (Phase I) Entergy Services, Inc., LPSC Complaint Regarding Single Operating Company Opportunity Sales, April 2010.
LPSC Docket No. U-31066 Dixie Electric Membership Corporation, Company's Application to Implement a Storm Recovery Rate Rider, May 2010.
FERC Docket No. EL10-55 Entergy Services, Inc.
LPSC Complaint Regarding Depreciation Rates, September 2010.
LPSC Docket No. U-23327, Subdocket E Southwestern Electric Power Company, 2003-2004 Fuel Audit, September 2010.
LPSC Docket No. U-23327, Subdocket F Southwestern Electric Power Company, 2009 Test Year Formula Rate Plan Filing, October 2010.
LPSC Docket No. U-23327, Subdocket C Southwestern Electric Power Company, 2007 Test Year Formula Rate Plan Filing, February 2011.
LPSC Docket No. U-23327, Subdocket D Southwestern Electric Power Company, 2008 Test Year Formula Rate Plan Filing, February 2011.
FERC Docket No. ER10-2001 Entergy Arkansas, Inc., Company's 2010 Filing to Request Approval of Changed Depreciation Rates, March 2011.
FERC Docket No. ER11-2161 Entergy Texas, Inc., Company's 2010 Filing to Request Approval of Changed Depreciation Rates, July 2011.
LPSC Docket No. U-31835 South Louisiana Electric Cooperative Association, Company's Application to Implement a Formula Rate Plan and Initial Revenue Adjustment, August 2011.
FERC Docket No. ER12-1384 Entergy Services, Inc., Company's Section 205 Fling Related to Little Gypsy 3 Cancellation Costs, September 2012.
LPSC Docket No. U-32315 Claiborne Electric Cooperative, Inc.'s Application to Implement a Formula Rate Plan and Initial Revenue Adjustment, September 2012.
FERC Docket No. ER10-1350 Entergy Services, Inc., Company's 2010 Filing to be in Compliance with FERC Opinions' 480 and 480-A, January 2014.
FERC Docket No. EL-01-88-015 Entergy Services, Inc., Company's 2005 Remand Filing to be in Compliance with FERC Opinions' 480 and 480-A, March 2016.
LPSC Docket No. U-33984 Claiborne Electric Cooperative, Inc., Formula Rate Plan Extension, October 2016.
FERC Docket No. EL09-61(Phase III) Entergy Services, Inc., LPSC Complaint Regarding Single Operating Company Opportunity Sales, November 2016.

LPSC Docket No. U-33323 Entergy Louisiana LLC, 2010-2013 Fuel Audit, July 2019.
LPSC Docket No. U-33324 Entergy Gulf States Louisiana LLC, 2010-2013 Fuel Audit, July 2019.
LPSC Docket No. U-35441 Southwestern Electric Power Company, Rate Case, July 2021 Direct, October 2021 Surrebuttal.

Direct Testimony filed on behalf of the Florida OPC:
FPSC Docket Nos. 20200241-EI, 202100178-EI, and 202100179-EI Florida Power and Light Company and Gulf Power Company, Storm Cost Audit, May 2022.

Direct Testimony filed on behalf of the KY AG:
KPSC Case No. 2022-00372 Duke Energy Kentucky, Inc. (Electric Division), Rate Case, March 2023.
KPSC Case No. 2023-00276 Kenergy Corp., Rate Case, January 2024.
KPSC Case No. 2024-00211 Licking Valley Rural Electric Cooperative Corporation, Rate Case, October 2024.
KPSC Case No. 2024-00276 Atmos Energy Corporation, Rate Case, January 2025.

Direct Testimony filed on behalf of the KY AG and the City of Clinton:
KPSC Case No. 2022-00147 Water Service Corporation of Kentucky, Rate Case, October 2022.

Direct Testimony filed on behalf of the KY AG and KIUC:
KPSC Case No. 2022-00263 Kentucky Power Company, Fuel Adjustment Clause – Six-Month Review, December 2022.
KPSC Case No. 2023-00318 Kentucky Power Company, Tariff PPA Modification, November 2023.
KPSC Case No. 2023-00008 Kentucky Power Company, Fuel Adjustment Clause – Two-Year Review, December 2023.

Direct Testimony filed on behalf of the South Carolina ORS:
SCPSC Docket No. 2022-256-E Duke Energy Progress, LLC, Cost Recovery for 8 Named Storms Since 2014, January 2023.

Direct Testimony filed on behalf of the OEG in Ohio:
PUCO Case No. 23-301-EL-SSO FirstEnergy Utilities, Standard Service Offer in the Form of an Electric Security Plan, October 2023.

Direct Testimony filed on behalf of Georgia Public Service Commission Staff:
GPSC Docket No. U-43830 Atlanta Gas Light Company, Affiliate Audit, May 2024.

Direct Testimony filed on behalf of Cities Served by Texas Gas Service Company:

Texas Railroad Commission Case No. OS-24-00017471 Texas Gas Service Company, Rate Case, August 2024.

| | |
|---|---|
| **Telscape International, Inc.** | **1997 - 2003** |
| **Corporate Controller** | **1999 - 2003** |
| **Assistant Controller** | **1997 - 1999** |

Complete responsibility and accountability for the accounting and financial functions of a $160 million newly public company providing telecommunication and high-end internet access services. Telscape served as a telephony carrier of services domestically and to Latin and Central America targeting other service carriers as well as individuals. Reported directly to CFO and managed a staff of eleven.

- Managed the day to day processes required to produce timely and accurate financial statements, including general ledger, account reconciliations, AP, AR, fixed assets, payroll, treasury, tax, internal and external reporting.

- Worked with attorneys and auditors on mergers and acquisitions including due diligence, audits, tax and integrating the accounting functions of eleven acquisitions.

- Grew the accounting department from four to eleven employees while developing and implementing company policies and procedures.

- Instituted capital investment policy and accounts payable management for twenty-one separate entities and twenty-four bank accounts to facilitate effective use of cash flow.

- Created capital and operating budgeting and variance analysis package for five separate business lines.

- Developed the consolidations and inter-company billings process across all entities including six in Latin and Central America.

- Worked with CFO to develop financial models and business plans in raising over $240 million over a three-year period through private preferred placements, debenture offerings and asset based credit facilities.

- Responsible for relationship management with external auditors, attorneys, and the banking community while reviewing and approving all SEC filings, including quarterly and annual reports, proxies and informational filings.

- Developed line cost accounting for revenues and carrier invoices saving thousands monthly and providing the justification for invoice reductions.

| | |
|---|---|
| **Comcast Communications, Inc.** | **1988 - 1997** |
| **Regional Controller** | **1993 - 1997** |
| **Regional Assistant Controller** | **1991 - 1992** |
| **Regional Senior Financial Analyst** | **1988 - 1991** |

Complete responsibility and accountability for the accounting functions of a $2.1 billion regional division of the world's third largest cable television provider serving approximately 490,000 subscribers. Reported to the Regional VP of Finance and managed a staff of twelve.

- Managed the day to day processes required to produce timely and accurate financial statements, including general ledger, account reconciliations, AP, AR, fixed assets and internal reporting.

- Controlled extensive budgeting, forecasting, and variance reporting for eighteen separate entities covering eight states, training employees and management throughout the region.

- Performed due diligence related to the acquisition of seven cable system entities and coordinated the integration of all accounting functions with the corporate office.

- Instituted all FCC informational and rate increase filings throughout the region based on the Cable Act of 1992.

- Responsible for the coordination of all subscriber reporting, sales and property tax filings, franchise fee and copyright filings.

- Grew the accounting department from seven to thirteen before its move to Atlanta, restaffing ninety percent of the department after the move.

- Directed all efforts throughout the region to implement Oracle as the new financial package and a new Access database for the budgeting and forecasting processes.

| | |
|---|---|
| **Storer Cable Communications, Inc** | **1987 - 1988** |
| **Senior Accountant for Operations** | |

Responsibility for the accounting, budgeting, and forecasting activities of this 82,000 subscriber area for this cable television concern that was acquired by Comcast listed above. Reported to the Area VP and General Manager and managed three employees.

- Implemented new Lotus based model for budgeting and forecasting, training all management on its use.

- Transitioned financial statement preparation from the regional office level to this area office.

- Managed the day to day processes required to produce timely and accurate financial statements for six separate entities including general ledger, AP, AR, fixed assets, subscriber reporting and other internal reporting.

- Developed and maintained tracking mechanism to track progress of cable plant rebuild and the associated competitor overbuild in the area's largest cable system.

**Tracey-Luckey Pecan & Storage, Inc. — 1986 - 1987**
**Senior Accountant**

Responsibility for the accounting, budgeting, and office management for a divisional office of this pecan production, processing, and storage entity annually grossing approximately $22 million. Financial statements were produced for three entities. Reported directly to the president of the division and managed three employees.

**Tarpley & Underwood, CPA's — 1984 - 1986**
**Staff Accountant**

Responsibility for the completion of monthly and quarterly client write-up for twenty-three small businesses for this regional CPA firm that is now one of the top twenty-five firms in Atlanta. Performed all payroll tax, sales tax, property tax, and income tax filings for these and other clients as well as approximately eighty individual returns per year. Reported directly to both partners with dotted line responsibility to all managers.

**EXHIBIT RAF-2**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's First Set of Data Requests**
**Date Received: January 8, 2025**

**AG-DR-01-054**

**REQUEST:**

Refer to the Adams Testimony and Attachment MJA-2 at page 4, regarding the lead/lag study he performed.

a. Indicate the source of the test period annual expense amounts for each expense category and explain why those amounts differ from the amounts included on Schedules C-1 and C-2.

b. If the test period annual revenue and expense amounts were not synchronized with the as-filed amounts provided elsewhere in the application schedules, provide a corrected CWC calculation.

c. Indicate why there are zero test period annual expenses reflected for each of the following even though there are calculated (lead)lag days for each:

Line 6 – Natural Gas

Line 7 – Oil

Line 25 – Franchise Tax

Line 28 – Federal Unemployment Taxes

Line 29 – State Unemployment Taxes

Line 30 – Gross Receipts License Tax

Line 31 – Sales & Use Tax

**RESPONSE:**

a. Please see the tables below for the source of each test period annual expense amounts presented on Attachment MJA-2, page 4.

| Test Period Annual Expense Category | Test Period Annual Expense | Source |
|---|---|---|
| Sales and Transportation Revenue | $449,303,309 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Other Revenues | $3,405,048 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| | | |
| Natural Gas | $0 | |
| Oil | $0 | |
| Coal | $48,545,844 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Purchased Power | $99,073,890 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Lime | $13,133,400 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Emission Fee | $450,656 | Exhibit MJA-2, Page 15 |
| Transm of Elec By Others | $29,352,086 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Labor | $26,398,176 | Schedule G-1, Page 1, Line 9 |
| Incentive Pay STIP | $1,342,964 | Schedule D-2.28, Page 1, Line 1 |
| Incentive Pay LTIP | $92,791 | Schedule D-2.28, Page 2, Line 7 - Schedule D-2.28, Page 2, Line 10 |
| Employee Pensions & Benefits - Acct 926 | $5,682,962 | Schedule G-1, Page 1, Line 11 |
| Prepaid Expenses | | |
| KY PSC Assessment Acct 928006 | $755,244 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Insurance - Property & Liability | $206,377 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Intercompany Transactions | $5,912,170 | Exhibit MJA-2, Page 22 |
| Other O&M Expenses | $47,583,150 | See Line 25 of Other O&M Reconciliation Below |
| | | |
| Franchise Tax | $0 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Property Taxes | $16,578,684 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Payroll Taxes | $1,730,362 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Federal Unemployment Taxes | $0 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| State Unemployment Taxes | $0 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Gross Receipts License Tax | $0 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| Sales & Use Taxes | $0 | “FORECASTED PERIOD” Tab of WPC-2.1A |
| | | |
| Federal Income Taxes | $4,850,656 | See Note 1 Below |
| State Income Taxes | $368,613 | See Note 1 Below |

Other O&M Reconciliation

| | Total Oper & Maint Exp incl Fuel & Purch Power | | Source |
|---|---|---|---|
| (1) | Per Forecasted Period Income Statement | $311,815,820 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (2) | Per Lead Lag | $278,529,710 | |
| | Items Excluded from Lead Lag Total O&M | | |
| (3) | NOx Sales Proceeds Native Excl Acct 411834 | $0 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (4) | Retail Deferred Fuel Expenses - Non Cash | ($1,086,449) | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (5) | Fuel Expense Acct 501996 - Excess Generati | ($16,120,437) | WPC-2e, Line 5 |
| (6) | Purch Pwr - Non-native - net Acct 555028 | $0 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (7) | Other Expenses-Oper Acct 557 DSM | ($8,283,237) | WPC-2e, Line 7 |
| (8) | Scheduling-Sys Cntrl&Disp Svs Acct 561400 | ($1,200,000) | WPC-2e, Line 5 |
| (9) | DSM Deferral & Carrying Charges Acct 407 | $0 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (10) | Sale of AR Acct 426 | $0 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (11) | Uncollectible Accounts Acct 904 Non Cash | ($2,366,517) | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (12) | Pension Adjustment | ($533,600) | WPC-2e, Page 1, Line 14 |
| (13) | Eliminate Misc Exp Adj | ($1,067,028) | WPC-2e, Page 1, Line 8 |
| (14) | Incentive Comp Adj | ($2,324,831) | WPC-2e, Page 1, Line 13 |
| (15) | DSM Adjustment | ($304,011) | WPC-2e, Page 1, Line 7 |
| | | | |
| (16) | Tie In to Forecasted Period | $278,529,710 | line 1 + (line 3 through line 15) |
| | | | |
| (17) | Coal | $48,545,844 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (18) | Purchased Power | $99,073,890 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (19) | Lime | $13,133,400 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (20) | Emission Fee | $450,656 | Exhibit MJA-2, Page 15 |
| (21) | Transm of Elec By Others | $29,352,086 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (22) | Labor | $26,398,176 | Schedule G-1, Page 1, Line 9 |
| (23) | Incentive Pay STIP | $1,342,964 | Schedule D-2.28, Page 1, Line 1 |
| (24) | Incentive Pay LTIP | $92,791 | Schedule D-2.28, Page 2, Line 7 - Schedule D-2.28, Page 2, Line 10 |
| (25) | Employee Pensions & Benefits - Acct 926 | $5,682,962 | Schedule G-1, Page 1, Line 11 |
| (26) | Prepaid Expenses | | |
| (27) | KY PSC Assesment Acct 928006 | $755,244 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (28) | Insurance - Property & Liability | $206,377 | "FORECASTED PERIOD" Tab of WPC-2.1A |
| (29) | Intercompany Transactions | $5,912,170 | Exhibit MJA-2, Page 22 |
| | | | |
| (30) | O&M Expense | $230,946,560 | Sum of lines 17 - 29 |
| (31) | Other O&M Expense | $47,583,150 | Line 16 - Line 30 |

b. While responding to this request, it was determined that the Miscellaneous Expense Adjustment and the Federal and State Income Taxes are not synchronized with the as-filed amounts provided elsewhere in the application schedules.

The Miscellaneous Expense Adjustment of ($1,067,028), on line 13 of the O&M reconciliation table in response a., is not the final adjustment included in the revenue requirement. The final Miscellaneous Expense Adjustment included in the revenue requirement is ($912,585), WPC-2e, Adjustment D-2.23.

The Federal and State Income Taxes of $4,850,656 and $368,613, respectively, presented in the response to a. are not representative of the final

Federal and State Income Tax amounts included in the final schedules. The current Federal and State Income Taxes included on Schedule C-2 are $3,532,523 and $40,444, respectively.

The Cash Working Capital analysis has been updated, and a revised calculation can be found in AG-DR-01-054 Attachment. Further, the overall impact of the updates to the Company's Forecasted Period Cash Working Capital requirement has been quantified in the table below.

| | |
|---|---|
| Forecasted Period CWC Requirement - As Filed | $ 4,507,797 |
| Update Miscellaneous Expenses | $ (14,985) |
| Update Federal and State Income Taxes | $ (36,193) |
| Updated CWC Requirement | $ 4,456,619 |

c. The Company did not include any expenses in the forecasted test year for the categories in question; therefore, no test period annual expenses are reflected in these expense categories.

**PERSON RESPONSIBLE:** Michael J. Adams

**EXHIBIT RAF-3**

**AG-DR-01-116**

**REQUEST:**

Describe how the DEBS EDIT is reflected in the Duke Kentucky electric revenue requirement. Provide the amounts reflected in rate base and/or cost of capital by temporary difference and the related effect on the Duke Kentucky electric revenue requirement, if any. Provide all data, assumptions, and calculations, including electronic workpapers with all formulas intact.

**RESPONSE:**

The DEBS EDIT amortization was inadvertently not included in the Duke Kentucky electric revenue requirement in this proceeding. The $16,407 should have been a reduction in the revenue requirement. If the amortization remains at $16,407 annually, the balance will be fully amortized by approximately the end of 2027.

**PERSON RESPONSIBLE:** Lisa D. Steinkuhl

**EXHIBIT RAF-4**

**AG-DR-02-061**

**REQUEST:**

Refer to the summary of regulatory assets on WPB-1-1a summing to $13,100,679 for the test year. Separately for each of the eight regulatory assets listed, indicate whether the test year revenue requirement contains a rate base offset for ADIT. If not, provide the amount of the ADIT offset associated with each regulatory asset that should have been included in the test year. If an ADIT offset for each is not required, explain why not.

**RESPONSE:**

| Account Number | Description | Total to be Amortized | Amortization Start Date | ADIT offset included |
|---|---|---|---|---|
| 182526 | Deferred Forced Outage Purchased Power | $2,683,502 | 7/1/2025 | Yes |
| 182526 | Deferred Forced Outage Purchased Power | $1,819,460 | 10/12/2023 | Yes |
| 182527 | Deferred Plant Outage O&M | $3,724,501 | 7/1/2025 | Yes |
| 182527 | Deferred Plant Outage O&M | $8,309,265 | 10/12/2023 | Yes |
| 182366 | Carbon Management Regulatory Asset | $2,000,000 | 5/1/2018 | Yes |
| | 2024-00xxx Rate Case Expense | $800,333 | 7/1/2025 | Yes |
| 186113 | 2019-00271 Rate Case Expense | $105,215 | 10/12/2023 | Yes |
| 186107 | 2022-00372 Rate Case Expense | $788,066 | 10/12/2023 | Yes |

**PERSON RESPONSIBLE:** Lisa D. Steinkuhl

**EXHIBIT RAF-5**

**DUKE ENERGY KENTUCKY**
**LEAD LAG STUDY**
**COLLECTIONS LAG**

| Month | Current (0 - 30) | 30 Days (30 - 60) | 60 Days (60 - 90) | 180 Days (90 - 120) | 365 Days (120 - 150) | >150 Days | Total |
|---|---|---|---|---|---|---|---|
| (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) |
| January 2023 | $ 59,010,859.18 | $ 2,122,830.91 | $ 1,071,638.41 | $ 724,303.24 | $ 542,591.31 | $ 2,606,660.01 | $ 66,078,883.06 |
| February 2023 | 53,131,798.70 | 2,537,790.28 | 1,077,056.07 | 711,933.82 | 460,754.01 | 2,278,228.77 | 60,197,561.65 |
| March 2023 | 37,764,842.61 | 2,901,960.99 | 1,435,914.85 | 703,468.83 | 539,296.56 | 2,017,272.45 | 45,362,756.29 |
| April 2023 | 34,843,300.33 | 2,509,457.37 | 1,816,907.13 | 1,047,405.49 | 514,826.10 | 1,965,937.53 | 42,697,833.95 |
| May 2023 | 28,811,225.34 | 1,421,982.46 | 1,409,640.85 | 1,323,770.46 | 749,691.06 | 1,828,309.09 | 35,544,619.26 |
| June 2023 | 33,862,592.28 | 1,785,584.84 | 929,679.62 | 1,085,250.37 | 976,281.50 | 1,944,637.13 | 40,584,025.74 |
| July 2023 | 33,781,022.74 | 1,361,251.97 | 891,053.02 | 674,848.57 | 773,638.11 | 2,275,222.45 | 39,757,036.86 |
| August 2023 | 32,901,447.68 | 1,315,708.69 | 602,137.66 | 553,232.71 | 513,566.34 | 2,292,292.02 | 38,178,385.10 |
| September 2023 | 37,258,962.28 | 1,542,367.80 | 657,524.95 | 392,485.06 | 399,217.30 | 2,171,295.53 | 42,421,852.92 |
| October 2023 | 31,072,583.96 | 1,274,826.98 | 701,404.60 | 443,446.73 | 243,975.36 | 1,941,747.70 | 35,677,985.33 |
| November 2023 | 34,061,587.36 | 1,307,345.48 | 684,107.10 | 464,304.78 | 300,797.99 | 1,740,239.60 | 38,558,382.31 |
| December 2023 | 45,836,972.14 | 1,436,912.52 | 764,855.22 | 462,930.75 | 307,674.16 | 1,700,903.46 | 50,510,248.25 |
| | $ 462,337,195 | $ 21,518,020.29 | $ 12,041,919.48 | $ 8,587,380.81 | $ 6,322,309.80 | $ 24,762,745.74 | $ 535,569,570.72 |
| Weighted Average | 86.33% | 4.02% | 2.25% | 1.60% | 1.18% | 4.62% | |
| Midpoint of Range | 15 | 45 | 75 | 105 | 135 | 150 | |
| Weighted Days | 12.95 | 1.81 | 1.69 | 1.68 | 1.59 | 6.94 | 26.66 |

**EXHIBIT RAF-6**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's Second Set of Data Requests**
**Date Received: February 12, 2025**

**AG-DR-02-054**

**REQUEST:**

Refer to the lead/lag study electronic workpapers of Mr. Adams provided in Duke Kentucky's response to the Attorney General's First Request, Item 53, and further to the calculation of the collections lag contained on worksheet tab AR Aging. Refer also to Duke Kentucky's response to the Attorney General's First Request, Item 57, wherein the Company states that it did not track separately the uncollectible expense and allowance data between gas and electric prior to 2024 due to the sale of receivables to Cinergy Receivables Corporation

a. Confirm that the receivables balances shown on worksheet tab AR Aging by month and aging bucket during 2023 are total Company receivables balances and not just for the electric division. If not confirmed, explain why not.

b. Provide an updated worksheet tab AR Aging calculation for the total Company receivables that contains all data for the months in 2024. Provide in electronic format with all formulas intact.

c. Provide an updated worksheet tab AR Aging calculation that includes only Duke Kentucky's electric division data for each month during 2024. Provide in electronic format with all formulas intact. If data is not available for each month in 2024, explain why not since the uncollectible expense and allowance data was provided for just the electric division for each month in 2024 in Duke Kentucky's response to the Attorney General's First Request, Item 57.

**RESPONSE:**

a. Confirmed. The receivable balances are total Company receivables balances.

b. Please see AG-DR-02-054(b) Attachment.

c. The electric division data is not available for each month in 2024 because the billing system does not maintain the Accounts Receivable Aging Reports by service. Activity is booked to the income statement by service.

**PERSON RESPONSIBLE:** Danielle L. Weatherston – a., c.
Michael J. Adams – b.

**Duke Energy Kentucky**
**AR Agings**
**January 2023 to December 2024**

| | Current (0 - 30) | 30 Days (30 - 60) | 60 Days (60 - 90) | 180 Days (90 - 120) | 365 Days (120 - 150) | >150 Days | Total |
|---|---|---|---|---|---|---|---|
| January 2023 | $ 59,010,859.18 | $ 2,122,830.91 | $ 1,071,638.41 | $ 724,303.24 | $ 542,591.31 | $ 2,606,660.01 | $ 66,078,883.06 |
| February 2023 | 53,131,798.70 | 2,537,790.28 | 1,077,056.07 | 711,933.82 | 460,754.01 | 2,278,228.77 | 60,197,561.65 |
| March 2023 | 37,764,842.61 | 2,901,960.99 | 1,435,914.85 | 703,468.83 | 539,296.56 | 2,017,272.45 | 45,362,756.29 |
| April 2023 | 34,843,300.33 | 2,509,457.37 | 1,816,907.13 | 1,047,405.49 | 514,826.10 | 1,965,937.53 | 42,697,833.95 |
| May 2023 | 28,811,225.34 | 1,421,982.46 | 1,409,640.85 | 1,323,770.46 | 749,691.06 | 1,828,309.09 | 35,544,619.26 |
| June 2023 | 33,862,592.28 | 1,785,584.84 | 929,679.62 | 1,085,250.37 | 976,281.50 | 1,944,637.13 | 40,584,025.74 |
| July 2023 | 33,781,022.74 | 1,361,251.97 | 891,053.02 | 674,848.57 | 773,638.11 | 2,275,222.45 | 39,757,036.86 |
| August 2023 | 32,901,447.68 | 1,315,708.69 | 602,137.66 | 553,232.71 | 513,566.34 | 2,292,292.02 | 38,178,385.10 |
| September 2023 | 37,258,962.28 | 1,542,367.80 | 657,524.95 | 392,485.06 | 399,217.30 | 2,171,295.53 | 42,421,852.92 |
| October 2023 | 31,072,583.96 | 1,274,826.98 | 701,404.60 | 443,446.73 | 243,975.36 | 1,941,747.70 | 35,677,985.33 |
| November 2023 | 34,061,587.36 | 1,307,345.48 | 684,107.10 | 464,304.78 | 300,797.99 | 1,740,239.60 | 38,558,382.31 |
| December 2023 | 45,836,972.14 | 1,436,912.52 | 764,855.22 | 462,930.75 | 307,674.16 | 1,700,903.46 | 50,510,248.25 |
| January 2024 | 61,666,211.38 | 1,528,564.66 | 768,580.02 | 484,857.08 | 317,586.03 | 1,597,397.55 | 66,363,196.72 |
| February 2024 | 59,965,067.02 | 1,620,653.33 | 791,143.28 | 433,337.99 | 314,093.57 | 1,538,799.68 | 64,663,094.87 |
| March 2024 | 49,486,853.96 | 2,491,440.54 | 930,745.74 | 521,844.61 | 289,959.28 | 1,507,205.84 | 55,228,049.97 |
| April 2024 | 39,411,289.68 | 1,817,700.46 | 1,460,553.05 | 593,247.07 | 357,025.46 | 1,461,825.22 | 45,101,640.94 |
| May 2024 | 35,222,397.82 | 1,630,461.96 | 1,075,455.35 | 988,865.99 | 411,011.90 | 1,419,074.13 | 40,747,267.15 |
| June 2024 | 38,603,515.59 | 1,410,181.09 | 962,450.47 | 774,488.52 | 668,925.58 | 1,495,974.04 | 43,915,535.29 |
| July 2024 | 47,425,229.00 | 913,762.00 | 782,548.09 | 630,394.16 | 585,540.27 | 1,686,015.15 | 52,023,488.67 |
| August 2024 | 42,473,692.00 | 1,265,312.00 | 626,753.72 | 481,658.31 | 419,916.43 | 1,708,120.11 | 46,975,452.57 |
| September 2024 | 38,651,022.00 | 1,603,107.00 | 623,530.55 | 386,060.67 | 298,235.91 | 1,581,839.97 | 43,143,796.10 |
| October 2024 | 31,744,565.00 | 1,149,443.00 | 819,880.01 | 403,184.25 | 253,405.64 | 1,416,550.68 | 35,787,028.58 |
| November 2024 | 36,988,078.00 | 1,362,128.00 | 684,572.34 | 551,533.62 | 267,609.44 | 1,373,016.24 | 41,226,937.64 |
| December 2024 | 42,073,150.00 | 864,947.42 | 647,621.43 | 475,834.40 | 323,979.94 | 1,336,404.45 | 45,721,937.64 |
| | $ 986,048,266.05 | $ 39,175,721.75 | $ 22,215,753.53 | $ 15,312,687.48 | $ 10,829,599.25 | $ 42,884,968.80 | $ 1,116,466,996.86 |
| Weighted Average | 88.32% | 3.51% | 1.99% | 1.37% | 0.97% | 3.84% | |
| Midpoint of Range | 15 | 45 | 75 | 105 | 135 | 150 | |
| Weighted Days | 13.25 | 1.58 | 1.49 | 1.44 | 1.31 | 5.76 | 24.83 |

**EXHIBIT RAF-7**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's First Set of Data Requests**
**Date Received: January 8, 2025**

**AG-DR-01-057**

**REQUEST:**

Refer to the Steinkuhl Testimony at page 10, regarding the proforma adjustment performed on Schedule D-2.21 to increase uncollectible expense by $1.785 million. Refer also to the electronic model STAFF-DR-01-054_Attachment_KPSC_Electric_SFRs-2024 provided in response to Staff discovery. Refer further to the tab SCH_H and to the monthly detail on WPH-a in regards to charge-offs and their percentages of revenues to determine the 0.921% uncollectible expense percentage.

a. In the same format as the month data provided for 2023 on WPH-a, provide the monthly gross charge offs, recoveries, net charge-offs, revenues, and percentage of revenues for each month during 2022 and for each month during 2024 for the electric division.

b. Confirm that all of the data provided on WPH-a applies to the electric division only. If not confirmed, explain why not.

c. Provide the amount of expense recorded in account 904 for uncollectible expense for the electric division for each month during 2022, 2023, and 2024.

**RESPONSE:**

a. Please see AG-DR-01-057 Attachment 1 for the monthly gross charge offs, recoveries, net charge-offs, revenues, and percentage of revenues for each month during 2022 through 2024 for the total Company. The Company did not track this data by gas and electric before 2024 because the Company sold its receivables to

Cinergy Receivables Corporation. The arrangement was terminated in March 2024. The Company now owns the retail receivables and needs to track the actual write-offs by the gas and electric division. Please see AG-DR-01-057 for the monthly gross charge offs, recoveries, net charge-offs, revenues, and percentage of revenues for each month during 2024 for the electric division.

b. The data provided on WPH-a does not apply to the electric division only. The Company did not track this data by gas and electric before 2024. The data on WPH-a was for total Company since sufficient historical data by gas and electric was not available to use in this application.

c. For years 2022 and 2023 as well as January and February 2024, Duke Energy Kentucky sold its receivables to Cinergy Receivables Corporation. Since the Company did not own the retail receivables, it recorded a loss on Sale of Receivables to FERC account 426 instead of recording an uncollectible expense to FERC account 904 related to is retail receivables. Please see AG-DR-01-057 Attachment 2 for the expense recorded in account 904 for uncollectible expense for the electric division for each month of 2024.

**PERSON RESPONSIBLE:** Danielle L. Weatherston / Lisa D. Steinkuhl

**Total Company 2022 through 2024**

| Line No. | Description | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Charge-offs | $324,253 | $263,630 | $249,423 | $430,013 | $508,922 | $298,398 | $351,801 | $361,221 | $385,672 | $382,634 | $282,931 | $330,761 | $4,169,659 |
| 2 | Recoveries | $88,048 | $102,977 | $99,668 | $79,446 | $95,834 | $86,827 | $92,997 | $82,445 | $79,282 | $103,842 | $112,257 | $96,693 | $1,120,316 |
| 3 | Net Charge-offs | $236,205 | $160,653 | $149,755 | $350,567 | $413,088 | $211,571 | $258,804 | $278,776 | $306,390 | $278,792 | $170,674 | $234,068 | $3,049,343 |
| 4 | | | | | | | | | | | | | | |
| 5 | Revenue | $48,114,413 | $45,182,928 | $36,392,870 | $34,547,847 | $37,686,613 | $35,096,973 | $51,637,711 | $47,615,149 | $36,920,551 | $35,120,980 | $33,656,618 | $37,829,721 | $479,802,374 |
| 6 | | | | | | | | | | | | | | |
| 7 | % of Revenue | 0.491% | 0.356% | 0.411% | 1.015% | 1.096% | 0.603% | 0.501% | 0.585% | 0.830% | 0.794% | 0.507% | 0.619% | 0.636% |

| Line No. | Description | Jan-23 | Feb-23 | Mar-23 | Apr-23 | May-23 | Jun-23 | Jul-23 | Aug-23 | Sep-23 | Oct-23 | Nov-23 | Dec-23 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Charge-offs | $510,155 | $457,742 | $413,757 | $467,729 | $616,659 | $424,436 | $451,268 | $432,402 | $305,795 | $394,311 | $335,228 | $292,569 | $5,102,051 |
| 2 | Recoveries | $68,316 | $123,945 | $112,709 | $76,603 | $99,249 | $112,769 | $94,840 | $168,297 | $138,528 | $84,483 | $66,363 | $67,088 | $1,213,190 |
| 3 | Net Charge-offs | $441,839 | $333,797 | $301,048 | $391,126 | $517,410 | $311,667 | $356,428 | $264,105 | $167,267 | $309,828 | $268,865 | $225,481 | $3,888,861 |
| 4 | | | | | | | | | | | | | | |
| 5 | Revenue | $47,312,635 | $33,197,716 | $27,604,312 | $17,525,453 | $35,187,926 | $35,847,105 | $34,869,511 | $40,074,407 | $41,263,057 | $34,543,129 | $34,320,746 | $40,472,676 | $422,218,673 |
| 6 | | | | | | | | | | | | | | |
| 7 | % of Revenue | 0.934% | 1.005% | 1.091% | 2.232% | 1.470% | 0.869% | 1.022% | 0.659% | 0.405% | 0.897% | 0.783% | 0.557% | 0.921% |

| Line No. | Description | Jan-22 | Feb-22 | Mar-22 | Apr-22 | May-22 | Jun-22 | Jul-22 | Aug-22 | Sep-22 | Oct-22 | Nov-22 | Dec-22 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Charge-offs | $167,914 | $145,794 | $277,350 | $9,419 | $13,505 | $153,425 | $234,686 | $301,835 | $352,176 | $755,030 | $456,567 | $368,005 | $3,235,706 |
| 2 | Recoveries | $39,679 | $42,881 | $71,330 | $34,203 | $42,951 | $199,434 | $47,539 | $59,307 | $70,298 | $53,305 | $63,044 | $54,972 | $778,943 |
| 3 | Net Charge-offs | $128,235 | $102,913 | $206,020 | -$24,784 | -$29,446 | -$46,009 | $187,147 | $242,528 | $281,878 | $701,725 | $393,523 | $313,033 | $2,456,763 |
| 4 | | | | | | | | | | | | | | |
| 5 | Revenue | $69,827,894 | $68,473,702 | $43,362,127 | $32,426,809 | $42,259,545 | $32,212,223 | $51,321,429 | $44,233,383 | $41,013,043 | $39,888,192 | $31,995,383 | $51,059,038 | $548,072,768 |
| 6 | | | | | | | | | | | | | | |
| 7 | % of Revenue | 0.184% | 0.150% | 0.475% | -0.076% | -0.070% | -0.143% | 0.365% | 0.548% | 0.687% | 1.759% | 1.230% | 0.613% | 0.448% |

**Electric Division Only for 2024**

| Line No. | Description | Jan-24 | Feb-24 | Mar-24 | Apr-24 | May-24 | Jun-24 | Jul-24 | Aug-24 | Sep-24 | Oct-24 | Nov-24 | Dec-24 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Charge-offs | $247,769 | $195,778 | $178,247 | $247,228 | $309,304 | $205,318 | $223,753 | $220,131 | $261,672 | $308,202 | $225,425 | $271,428 | $2,894,255 |
| 2 | Recoveries | $61,130 | $75,776 | $74,305 | $60,333 | $66,699 | $54,864 | $61,023 | $58,165 | $56,874 | $71,692 | $64,410 | $56,611 | $761,883 |
| 3 | Net Charge-offs | $186,639 | $120,002 | $103,942 | $186,895 | $242,605 | $150,454 | $162,730 | $161,966 | $204,798 | $236,510 | $161,015 | $214,817 | $2,132,372 |
| 4 | | | | | | | | | | | | | | |
| 5 | Revenue | $46,074,729 | $43,966,941 | $35,397,567 | $33,674,894 | $36,955,432 | $34,440,712 | $51,014,761 | $46,969,762 | $36,296,570 | $34,517,401 | $32,925,349 | $36,988,489 | $469,222,605 |
| 6 | | | | | | | | | | | | | | |
| 7 | % of Revenue | 0.405% | 0.273% | 0.294% | 0.555% | 0.656% | 0.437% | 0.319% | 0.345% | 0.564% | 0.685% | 0.489% | 0.581% | 0.454% |

| | |
|---|---|
| Business Unit Level 06 Name | DE_KENTUCKY |
| Business Unit CB | All |
| Journal Name | All |

| **Monetary Amount** | **Fiscal Year** | **Calendar Quarter** | **Accounting Period** | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2024** | | | | | | | | | | | | **Grand Total** |
| | **Q1 2024** | | | **Q2 2024** | | | **Q3 2024** | | | **Q4 2024** | | | |
| **Account CB** | **Jan 2024** | **Feb 2024** | **Mar 2024** | **Apr 2024** | **May 2024** | **Jun 2024** | **Jul 2024** | **Aug 2024** | **Sep 2024** | **Oct 2024** | **Nov 2024** | **Dec 2024** | |
| 0904000 | (36,850.13) | (25,134.46) | 140,011.71 | 345,793.65 | 415,536.78 | 203,854.06 | 252,494.40 | 272,118.11 | 300,941.51 | 280,046.35 | 167,629.15 | 231,220.85 | 2,547,661.98 |
| 0904001 | 10,247.86 | 18,587.30 | 123,567.94 | 6,763.42 | 3,270.86 | 13,124.80 | 6,310.29 | 11,617.90 | (593,745.14) | 1,472.33 | 6,292.90 | 2,847.21 | (389,642.33) |
| **Grand Total** | **(26,602.27)** | **(6,547.16)** | **263,579.65** | **352,557.07** | **418,807.64** | **216,978.86** | **258,804.69** | **283,736.01** | **(292,803.63)** | **281,518.68** | **173,922.05** | **234,068.06** | **2,158,019.65** |
| | | | | | | | | | | | | | |
| Misc Receivables Expense | 0.00 | 20,613.77 | 4,662.40 | 1,989.92 | 5,719.50 | 5,407.77 | 0.00 | 4,959.52 | 806.53 | 2,726.44 | 3,247.72 | 0.00 | 50,133.57 |
| | | | | | | | | | | | | | |
| Retail Receivables Expense | (26,602.27) | (27,160.93) | 258,917.25 | 350,567.15 | 413,088.14 | 211,571.09 | 258,804.69 | 278,776.49 | (293,610.16) | 278,792.24 | 170,674.33 | 234,068.06 | 2,107,886.08 |

**EXHIBIT RAF-8**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's First Set of Data Requests**
**Date Received: January 8, 2025**

**AG-DR-01-095**

**REQUEST:**

Refer to the electronic model STAFF-DR-01-054_Attachment_KPSC_Electric_SFRs-2024 provided in response to Staff discovery. Refer further to the worksheet tabs BASE PERIOD and FORECASTED PERIOD, which show expenses by FERC subaccount for each month and in total. Refer further to the base period amount of $24,452,046 expensed to account 565000 (Transmission of Electricity by Others) and to the forecast period amount of $29,352,086 expensed to the same account, an increase of $4,900,040, or 20%.

a. Provide the actual expense amount recorded to this account for each of the calendar years 2020 through 2024.

b. Explain all known reasons why the expense amount in this account is forecast to increase by 20% from the base year to the forecast year.

c. Provide a copy of all workpapers relied upon to forecast the test year amount for this account.

**RESPONSE:**

a.

| | |
|---|---|
| 2020 | $19,283,242 |
| 2021 | $19,455,367 |
| 2022 | $21,126,946 |
| 2023 | $22,364,509 |
| 2024 | $24,132,590 |

b. The majority of expenses recorded and forecast to this account relate to PJM NITS fees, which have been increasing significantly in recent years. In the forecasted portion of the base year and the test year, these expenses are projected to increase 11.7% annually based upon actual cost increases seen when comparing January-June 2023 to January-June 2024. This account also includes amounts recorded for accretion of MTEP obligations due to exiting MISO as of December 31, 2011, which was assumed to remain flat to 2022-2024 actual amounts.

c. Please see AG-DR-01-095 Attachment.

**PERSON RESPONSIBLE:** a. Danielle L. Weatherston
b.-c. Grady S. "Tripp" Carpenter

| Description | 2023 | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Total |
| MTEP Accretion | | | 139,250 | | | 139,250 | | | 139,250 | | | 139,250 | 557,000 |
| PJM NITS | 2,133,271 | 1,297,677 | 1,804,756 | 1,804,756 | 1,297,677 | 2,296,317 | 1,961,243 | 1,752,924 | 1,871,097 | 1,961,243 | 1,662,778 | 1,963,770 | 21,807,509 |
| | 2,133,271 | 1,297,677 | 1,944,006 | 1,804,756 | 1,297,677 | 2,435,567 | 1,961,243 | 1,752,924 | 2,010,347 | 1,961,243 | 1,662,778 | 2,103,020 | 22,364,509 |

| Description | 2024 | | | | | | |
|---|---|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | 5 | 6 | Total |
| MTEP Accretion | | | 139,250 | | | 139,250 | 278,500 |
| PJM NITS | 1,970,189 | 1,769,823 | 2,069,729 | 1,976,319 | 1,863,233 | 2,227,766 | 11,877,059 |
| | 1,970,189 | 1,769,823 | 2,208,979 | 1,976,319 | 1,863,233 | 2,367,016 | 12,155,559 |

| Escalation Calculation | |
|---|---|
| January through June 2023 | 10,634,454 |
| January through June 2024 | 11,877,059 |
| Escalation Percentage | 11.7% |

| 2024 Forecast | 2023 Actual | Escalation Factor | 2024 Forecast | | 2025 Forecast | | 2026 Forecast |
|---|---|---|---|---|---|---|---|
| MTEP Accretion (1/4th recorded quarterly) | 557,000 | 0% | 557,000 | 0% | 557,000 | 0% | 557,000 |
| PJM NITS | 21,807,509 | 11.7% | 24,358,987 | 11.7% | 27,208,989 | 11.7% | 30,392,440 |
| | | | 24,915,987 | | 27,765,989 | | 30,949,440 |

| | Acct 565000 |
|---|---|
| Calculated Test Year Expense | 29,357,714 |
| Test Year Expense per SFR | 29,352,086 |
| Variance | 5,628 |

**EXHIBIT RAF-9**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's First Set of Data Requests**
**Date Received: January 8, 2025**

**AG-DR-01-128**

**REQUEST:**

Provide the Directors & Officers ("D&O") insurance expense directly incurred by or allocated to the Duke Kentucky electric division included in the test year, showing how the allocations were performed.

**RESPONSE:**

The amount allocated to Duke Energy Kentucky electric division in the test year is $183,329. These costs are allocated to Duke Kentucky via the three factor formula per the Cost Allocation Manual (CAM).

**PERSON RESPONSIBLE:** Grady S. "Tripp" Carpenter

**EXHIBIT RAF-10**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's First Set of Data Requests**
**Date Received: January 8, 2025**

**AG-DR-01-130**

**REQUEST:**

Provide the Board of Directors ("BOD") compensation expense directly incurred by or allocated to the Duke Kentucky electric division included in the test year, showing how the allocations were performed.

**RESPONSE:**

The amount allocated to Duke Energy Kentucky electric division in the test year is $23,324. These costs are allocated to Duke Kentucky via the three factor formula per the Cost Allocation Manual (CAM).

**PERSON RESPONSIBLE:** Grady S. "Tripp" Carpenter

**EXHIBIT RAF-11**

**Duke Energy Kentucky**
**Case No. 2024-00354**
**AG's First Set of Data Requests**
**Date Received: January 8, 2025**

**AG-DR-01-129**

**REQUEST:**

Provide the Investor Relations expense directly incurred by or allocated to the Duke Kentucky – electric division included in the test year, showing how the allocations were performed.

**RESPONSE:**

The amount allocated to Duke Energy Kentucky electric division in the test year is $58,986. These costs are allocated to Duke Kentucky via the three factor formula per the Cost Allocation Manual (CAM).

**PERSON RESPONSIBLE:** Grady S. "Tripp" Carpenter

**AFFIDAVIT**

STATE OF GEORGIA )

COUNTY OF FULTON )

RANDY A. FUTRAL, 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.

Randy A. Futral

Sworn to and subscribed before me on this
5th day of March 2025.

Jessica K. In

Notary Public

Jessica K Inman
NOTARY PUBLIC
Cherokee County, GEORGIA
My Commission Expires 07/31/2027