COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC. FOR A GENERAL ADJUSTMENT OF RATES, APPROVAL OF DEPRECIATION STUDY, AMORTIZATION OF CERTAIN REGULATORY ASSETS, AND OTHER GENERAL RELIEF	**))))))**	**CASE NO. 2021-00103**

DIRECT TESTIMONY

AND EXHIBITS OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

AND NUCOR STEEL GALLATIN

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JUNE 2021

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KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES	**)**	**CASE NO. 2021-00103**
APPROVAL OF DEPRECIATION STUDY	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS AND OTHER GENERAL RELIEF	**)**	

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DIRECT TESTIMONY OF LANE KOLLEN

I. QUALIFICATIONS AND SUMMARY

Q. Please state your name and business address.

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

Q. Please state your occupation and employer.

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

Q. Please describe your education and professional experience.

A. I earned a Bachelor of Business Administration in Accounting degree and a Master of Business Administration degree from the University of Toledo. I also earned a Master of Arts degree in theology from Luther Rice University. I am a Certified

Public Accountant ("CPA"), with a practice license, a Certified Management Accountant ("CMA"), and a Chartered Global Management Accountant ("CGMA"). I am a member of numerous professional organizations, including the American Institute of Certified Public Accountants, the Institute of Management Accounting, and the Society of Depreciation Professionals.

I have been an active participant in the utility industry for more than forty years, initially as an employee of an electric and natural gas utility, then as a consultant assisting utilities in their resource planning and financial analyses, and thereafter as a consultant assisting government agencies and large users of electricity, natural gas, and water utility services. I have testified as an expert witness on ratemaking, accounting, finance, tax, and planning issues in proceedings before regulatory commissions and courts at the federal and state levels on hundreds of occasions, including numerous proceedings before the Kentucky Public Service Commission ("Commission") involving East Kentucky Power Company ("EKPC" or "Company"), Kentucky Utilities Company ("KU"), Louisville Gas and Electric Company ("LG&E"), Kentucky Power Company ("KPCo"), Duke Energy Kentucky, Inc. ("DEK"), Big Rivers Electric Corporation ("BREC"), Atmos Energy Corporation ("Atmos"), Columbia Gas of Kentucky, Inc. ("Columbia Gas"), Kentucky-American Water Company ("KAW"), and Water Service Corporation of Kentucky ("WSCK").[1]

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

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Office of the Attorney General of the Commonwealth of Kentucky ("AG") and Nucor Steel Gallatin ("Nucor"). The AG and Nucor have been active participants in EKPC ratemaking and other proceedings for many years.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to summarize the AG and Nucor adjustments to the Company's requested increase in its base revenues and related increase in its environmental surcharge ("ES") revenues and to address specific issues that affect these increases.

Q. Please summarize your testimony.

A. I recommend that the Commission reduce EKPC's present base rates by at least $18.625 million, a reduction of $61.625 million from its requested increase of $43.000 million.

In its Application, the Company claims a base revenue deficiency of $48.984 million, but requests a base rate increase of $43.000 million, a reduction of $5.984 million from the claimed deficiency. In response to Staff discovery, the Company states that it plans to achieve this reduction in the claimed deficiency through specified expense reductions.

In the following table, I reconcile the Company's claimed base revenue deficiency to its requested increase of $43.000 million[2] and then list each AG and Nucor recommendation and the adjustment to the Company's base revenue increase.[3] Although I do not quantify the effects on the following table, the Company's proposals and my recommendations also affect the ES revenue requirement, specifically with respect to the depreciation rates and depreciation expense, interest expense, and the Times Interest Earned Ratio ("TIER").

East Kentucky Power Cooperative, Inc.
Case Number 2021-00103
Summary AG-Nucor Revenue Requirement Recommendations
($ Millions)

	Adjustment Amount Before Gross-Up	Gross-Up Factor	Adjustment Amount After Gross-Up
Calculated Net Margin Revenue Requirement as Filed by EKPC			48.984
Less: EKPC Cost Containment Measures To Reduce Travel and Training Costs			(1.000)
Less: EKPC Cost Containment Measures To Reduce Outside Consulting/Contracting Services Costs			(4.984)
Amount of Increase Requested by EKPC			43.000
AG-Nucor Adjustments to EKPC's Calculated Revenue Requirement:			
Increase Capacity Revenues	(4.535)	1.002	(4.544)
Decrease Leased Property Income Net	2.062	1.002	2.066
Adjust Annualization of Payroll Expense	(2.632)	1.002	(2.638)
Adjust Annualization of Payroll Tax Expense	(0.249)	1.002	(0.249)
Reduce OPEB Expense to 2020 Actual Level	(1.033)	1.002	(1.035)
Adjust Forced Outage and Highest Purchased Power Expense Annualization	(1.924)	1.002	(1.928)
Reflect Normalization of Generation Maintenance Expense	(6.579)	1.002	(6.592)
Reduce Depreciation Expense to Remove Change in Methodology - Production	(12.063)	1.002	(12.087)
Reduce Depreciation Expense to Reflect 45 Yr Lifespans for Smith CT Units	(2.118)	1.002	(2.122)
Reduce Depreciation Expense to Reflect 45 Yr Lifespans for Bluegrass Oldham CT Units	(0.719)	1.002	(0.721)
Reduce Amortization Period for General Plant Reserve Surplus to 5 Years	(1.910)	1.002	(1.914)
Extend Amortization Period of Smith 1 Regulatory Asset to 84 Months	(3.487)	1.002	(3.494)
Reduce Interest Expense Related to Additional ES Projects Not Removed	(8.534)	1.002	(8.551)
Reduce Interest Expense Related to Short-Term Investments	(6.239)	1.002	(6.252)
Reflect TIER of 1.30	(11.542)	1.002	(11.565)
Total AG-Nucor Adjustments to EKPC's Requested Increase			(61.625)
AG-Nucor Recommended Minimum Rate Decrease for EKPC			(18.625)

[2] Response to Staff 2-12. Although the Company did not reflect these adjustments in its schedules and workpapers, it reduced its claimed base revenue deficiency by $5.984 million to reflect planned expense reductions. The Company states: "EKPC will reduce travel and training costs by $1 million. This can be achieved by participating in certain training activities virtually, as this may be the trend of the future. EKPC will reduce outside consulting/contracting services by $5 million and perform such services in-house."

[3] The calculations are detailed in my workpapers, which have been filed with my testimony in the form of an Excel workbook in live format.

Q. Did the Company strictly adhere to its 2019 historic test year in quantifying its claimed base revenue deficiency?

A. No. The Company proposes at least seven selective post-test year adjustments that increase its claimed revenue deficiency in the aggregate by $16.532 million based on known and measurable changes in 2020. These include adjustments to reflect annualized interest expense and the related TIER at 1.50X at June 30, 2020 (reduction of $14.598 million), interest income at June 30, 2020 (increase of $17.487 million), payroll and related expenses based on a single payroll on September 18, 2020 (increase of $4.676 million), annualized retiree medical insurance estimated in 2020 (reduction of $1.193 million), annualized property insurance expense in 2020 (increase of $0.322 million), employee medical insurance at June 30, 2020 (increase of $0.474 million), and regional transmission expansion plan ("RTEP") expenses based on the first six months of 2020 (increase of $9.362 million).[4]

Q. Were the Company's proposed selective post-test year adjustments comprehensive?

A. No. They did not reflect other known and measurable changes. Consequently, I recommend additional adjustments for other known and measurable changes in 2020. The additional adjustments are necessary to provide a more comprehensive

[4] Increases and reductions refer to increases and reductions in the base revenue requirement.

and balanced set of post-test year adjustments and for a more accurate quantification of the Company's base revenue deficiency or surplus. The additional adjustments are included in the preceding table.

II. OPERATING REVENUE

A. Capacity Benefit Revenues

Q. Did the Company normalize capacity benefit revenues for known and measurable changes?

A. No. Capacity benefit revenues are the net of the Company's capacity sales revenues less the expense of the capacity purchases necessary to serve its load.[5] In 2019, the Company's net capacity benefit revenues were $6.330 million. In 2020, the Company's net capacity benefit revenues were $10.865 million, an increase in actual capacity benefit revenues of $4.535 million. In 2021, the Company's year to date actual net capacity benefit revenues on an annualized basis are approximately the same as the actual revenues in 2020.

Q. Is the increase in 2020 a known and measurable change compared to 2019?

A. Yes. The net capacity benefit revenues in 2020 are actual amounts based on the actual net capacity sales revenues and purchase expense in the PJM markets. The net capacity benefit revenues in 2020 include the first full year of capacity revenues

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[5] Response to AG-Nucor 1-75. I have attached a copy of that response as my Exhibit___(LK-2).

from the additional capacity available for sale in the PJM markets after the expiration in May 2019 of a tolling agreement with LG&E for the capacity and energy of the 165 MW Bluegrass Oldham Unit 3 combustion turbine ("CT") generating unit.[6]

Q. What is your recommendation?

A. I recommend that the Commission reflect the actual capacity benefit revenues recorded in 2020. The increase of $4.535 million in 2020 is a known and measurable change compared to the test year.

B. <u>Leased Property Income - Net</u>

Q. Describe the Company's leased property income – net revenues recorded in 2019 and 2020.

A. The Company recorded $2.419 million in leased property income – net revenues in 2019 and $0.591 million in 2020, a reduction of $2.062 million. The reduction in 2020 was due to the expiration of the Bluegrass Oldham 3 tolling agreement with LG&E in April 2019.

Q. Did the Company adjust leased property income – net revenues recorded in the test year for known and measurable changes?

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[6] Refer to the Company's 2019 Annual Report at 14. I have attached a copy of this page as my Exhibit___(LK-3). This page was provided in the Application at Exhibit 35 – Attachment 1 at page 15 of 79.

A. No**.** The Company proposed no adjustments to the leased property income – net recorded in the test year.

Q. Is the reduction in 2020 a known and measurable change?

A. Yes. The tolling agreement expired in the test year. The leased property income – net revenues recorded in 2020 reflects this fact as well as any other changes in those revenues.

Q. What is your recommendation?

A. I recommend that the Commission reflect the actual leased income - net revenues recorded in 2020. The reduction of $2.062 million in 2020 is a known and measurable change compared to the test year. I should note that this recommendation is paired with and dependent on the Commission reflecting the actual net capacity benefit revenues recorded in 2020. The incremental Bluegrass Oldham 3 capacity revenues from the sale into the PJM markets in 2020 are reflected in the net capacity benefit revenues recorded in 2020. The two adjustments are interrelated and should be reflected consistently at the levels recorded in 2020.

III. OPERATING EXPENSES

A. <u>Payroll Expense and Payroll Tax Expense Annualizations</u>

Q. Describe the Company's adjustments to annualize and increase payroll

expense and payroll tax expense.

A. The Company proposes adjustments to annualize payroll expense and the related payroll tax expense based on its September 18, 2020 payroll. This payroll reflects the staffing and compensation levels at that date, including significant increases in full-time and part-time employees as well as salaries and wages increases that occurred after the end of the historic test year.

The proposed adjustments to annualize payroll expense and related payroll tax expense reflect an increase of 24 full-time employees, from 688 at the end of the test year to 712 in September 2020, and an increase of 1 part-time employee, from 20 at the end of the test year to 21 in September 2020.

The adjustments increased payroll expense in the base revenue requirement by $4.262 million, or 6.5%, after adjustments to remove the expenses included in the ES.[7] The adjustments increased payroll tax expense in the base revenue requirement by $0.405 million, or 8.6%, after adjustments to remove the expenses included in the ES.[8]

The adjustments increased the other power generation payroll expense for base and ES revenue requirements by $1.951 million, or 35.6%. The adjustments increased the other power supply payroll expense for base and ES revenue requirements by $0.316 million, or 9.7%. The adjustments increased the transmission payroll expense for base and ES revenue requirements by $1.120 million, or 9.6% over the actual test year expense included in the base and ES

[7]Application_Exhibit_13_-_Exhibit_ISS-1_-_Workpaper_1.07_Wages-Salaries_FINAL.
[8] Application_Exhibit_13_-_Exhibit_ISS-1_-_Workpaper_1.08_Payroll_Tax_FINAL.

revenue requirements. The adjustments increased administrative and general payroll expense included in the base and ES revenue requirements by $1.533 million, or 11.6% over the test year.

Q. Are these adjustments reasonable?

A. No. The proposed increases are excessive, not known and measurable, and fail to reflect offsetting savings in contractor expenses achieved after the end of the test year. The proposed increases are based on the annualization of a single payroll and do not represent the actual annual increases in 2020, which were less than the proposed increases in the aggregate. The Company stated the following in response to several AG-Nucor discovery requests, which differ only by the category of expense referenced in the question and response.

> The reason for the change in the Transmission O&M wages and salaries presented on Schedule 1.07 is the result of preparing the payroll normalization based on a single payroll.[9]

The proposed adjustment to payroll expense reflects an increase in the aggregate that is more than 4 times the rate of inflation in 2020,[10] although a portion of the increase was due to the addition of new positions. The Company has a history in recent years of annual payroll increases that significantly exceed the rate of

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[9] Responses to AG-Nucor 1-53, 1-54, and 1-55. I have attached a copy of each of those responses as my Exhibit___(LK-4).

[10] The actual rate of inflation, as measured by the Consumer Price Index for All Urban Consumers ("CPI-U"), was 1.4% in 2020 and 2.3% in 2019, an average of 1.9%. CPI Home : U.S. Bureau of Labor Statistics (bls.gov).

inflation, and which cumulatively already are reflected in the payroll expense actually recorded in the test year.[11] The Company's proposed adjustment repeats and compounds this pattern of excessive payroll expense increases.

In addition, the payroll expense increases reflect the addition of new positions that do not reflect the actual operation of the Company in the test year and that have not been justified as necessary to operate the Company now or in the future. Further, to the extent that the positions were added to displace contractors in order to achieve savings, then there should be an offsetting reduction in contractor expense that is greater than the portion of the increases due to the additional positions. However, the Company failed to propose the necessary offsetting savings adjustment.

Q. What is your recommendation?

A. I recommend that the Commission allow an adjustment for cost of living and merit increases of 2.0% and 0.5%, respectively, or 2.5% in total, with no increase for the additional positions, which have not been justified and have not been offset with an adjustment for savings to the extent the positions were added to achieve savings in contractor expense.

I recommend an increase of 3.3% in the related payroll tax expense. I determined this increase by multiplying the 2.5% increase in payroll expense times a factor of 1.32, which is the ratio of the Company's proposed percentage increase

[11] Response to Staff 1-23. I have attached a copy of that response as my Exhibit___(LK-5).

in payroll tax expense divided by its proposed percentage increase in payroll expense.

Q. What are the effects of your recommendations?

A. The effects are a reduction in the adjusted payroll expense of $2.632 million and a reduction in the adjusted payroll tax expense of $0.249 million.

B. <u>Benefits Expense Annualization</u>

Q. Describe the Company's proposed adjustment to reduce retiree medical insurance expense.

A. The Company proposes an adjustment to reduce retiree medical insurance expense by $1.190 million.[12] This adjustment reflects its estimate of the savings from moving to a Medicare Advantage plan from a self-funded plan effective January 1, 2020.[13]

Q. How does the Company's proposed adjustment compare to the actual reduction in other postretirement benefits ("OPEB") expense recorded for accounting purposes in 2020?

A. The Company's actual OPEB expense in 2020 was $1.058 million, a reduction of $2.223 million compared to the actual OPEB expense of $3.281 million incurred in

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[12] Refer to Tab 1.11 Retiree Med Ins in Application_Exhibit_13_-_Exhibit_ISS-1_-_Schedules_1.00-1.30_FINAL_REV_03-08.xlsx.

[13] *Id.*

2019.[14] The Company's proposed reduction was based on an estimate and does not reflect the actual savings.

Q. Is the actual savings known and measurable and a better quantification of the savings, as well as all other changes to OPEB expense, than the Company's estimate?

A. Yes.

Q. What is your recommendation?

A. I recommend that the Commission reduce OPEB expense by $1.033 million in addition to the Company's proposed adjustment, for a total adjustment of $2.223 million.

C. <u>Forced Outage and Highest Purchased Power Expense Annualization</u>

Q. Describe the Company's proposed adjustment to normalize the forced outage and highest purchased power expense.

A. The Company proposes an adjustment to normalize and increase the highest forced outage and highest purchased power expense that is not recoverable through the fuel adjustment clause ("FAC") rider. The Company calculated a five-year average for the years 2015 through 2019 for this purpose.[15] The Company used the

[14] Response to AG-Nucor 1-57. I have attached a copy of the narrative portion of that response as my Exhibit___(LK-6).

[15] Sch 1.23 – Forced Outage High PP in Application_Exhibit_13_-_Exhibit_ISS-1_-_Schedules_1.00-1.30_FINAL_REV_03-08.xlsx.

following expenses to calculate its proposed adjustment.[16]

Adjustment for Forced Outage and Highest Purchssed Power Expenses Excl from FAC

Calendar Year	Highest Cost Exclusion	Disallowed Forced Outages
2015	$6,757,298	$441,598
2016	$3,494,376	$445,000
2017	$1,720,480	$5,004,309
2018	$3,610,893	$2,664,484
2019	$492,122	$1,236,831
Five-Year Totals	$16,075,169	$9,792,222
Average Annual Amounts	$3,215,034	$1,958,444
Expense for 2019	$492,122	$1,236,831
Differences	$2,722,912	$721,613
Adjustment for Forced Outage & Highest Cost Exclusion		$3,444,525

Q. What were the actual expenses excluded from the FAC in 2020?

A. The actual highest cost purchased power expense and disallowed forced outage expense were $0.309 million and $0.068 million in 2020, respectively.[17] These expenses were lower in 2020 than in any of the five prior years.

Q. Was the highest cost purchase power expense exclusion in 2015 due in part to a highly unusual event?

A. Yes. In response to AG-Nucor discovery, the Company confirmed that nearly half of the 2015 expense was due to a highly unusual event.

> Nearly half of the $6,757,298 highest-cost exclusion for 2015 occurred in February 2015, which was due to extremely cold temperatures occurring throughout the Eastern connection. Both EKPC and PJM set all-time winter peaks on February 20, 2015 at hour ending 0800. Increased demand in the

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[16] *Id.*

[17] Response to AG-Nucor 1-61. I have attached a copy of that response as my Exhibit___(LK-7).

> PJM footprint drove up hourly market prices well beyond EKPC's highest-cost units available.[18]

Q. If the Commission adopts the Company's proposed normalization adjustment, should it exclude the highly unusual expense incurred in 2015?

A. Yes. The 2015 expense is not recurring or indicative of future highest purchased power expense excluded from the FAC.

Q. Was the disallowed forced outage expense in 2017 due in part to unusual events?

A. Yes. In response to AG-Nucor discovery, the Company confirmed that more than half of the 2017 expense was due to unusual events as follows.

> **Request 1-63.** Refer to Exhibit ISS-1 Schedule 1.23. Describe all known reasons why the disallowed forced outages for 2017 of $5,004,309 was almost double that for any other listed year and over ten times as high as the amounts reflected for 2015 and 2016.
>
> **Response 1-63.** In 2017, Spurlock Station Units 3 and 4 encountered multiple platen superheater tube leaks that resulted in forced outages of longer duration than typical for the units. Spurlock Station Unit 2 also experienced multiple forced outages in March 2017 related to water wall leaks, which were ultimately replaced as part of the fall 2017 planned outage for Unit 2. Because the cost of substitution power was greater than the cost of generation lost from the units, the forced outage disallowances for the months these forced outages occurred totaled approximately $2.8 million.

Q. Are the expenses incurred in 2020 known and measurable?

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[18] Response to AG-Nucor 1-62. I have attached a copy of that response as my Exhibit___(LK-8).

A. Yes. They reflect a downward trend that started in 2019 compared to 2018 and prior years.

Q. What is your recommendation?

A. I recommend that the Commission normalize the highest purchased power expense and forced outage expense excluded from the FAC using the five years from 2016 through 2020 rather than the Company's proposed five years from 2015 through 2019. The more recent five-year period excludes the unusual highest purchased power expense incurred in 2015 and represents more recent data. I also recommend that the Commission exclude the forced outage expense for the Spurlock Units 2, 3, and 4 multiple forced outages in 2017 due to multiple platen superheater tube leaks and water wall leaks. They were not typical and were replaced in the planned outage later in 2017.

If, however, the Commission uses the five years from 2016 through 2019, then I not only recommend that it exclude the forced outage expense for the Spurlock Units 2, 3, and 4 multiple forced outages in 2017, I also recommend that the Commission exclude half of the highest purchased power expense in 2015 that was due to a highly unusual event.

Q. What are the effects of your recommendations?

A. The effects are reductions in the adjusted highest purchased power expense and in the forced outage expense excluded from the FAC of $1.290 million and $0.635 million, respectively, using the five years from 2016 through 2020 and excluding a portion of the forced outage expense in 2017. The effects of my alternative recommendations are reductions in the adjusted highest purchased power expense and in the forced outage expense excluded from the FAC of $0.676 million and $0.560 million, respectively, using the five years from 2015 through 2019 and excluding a portion of the highest purchased power expense in 2015 and a portion of the forced outage expense excluded from the FAC in 2017.

D. <u>Generation Maintenance Expense Normalization</u>

Q. Did the Company propose an adjustment to normalize major generation outage maintenance expense?

A. No. The Company proposes no adjustments to the actual production operation and maintenance expense in the test year, except to remove the expenses recovered in the ES.[19]

Q. Has the Commission allowed or required that other utilities normalize major generation outage maintenance expense?

A. Yes. The Commission repeatedly has allowed or otherwise required that other utilities normalize major generation outage expense. This includes KU, LG&E, KPCo, and DEK.

The Commission has found that normalization of major generation outage

[19] Refer to Tab 1.00 - Summary in Application_Exhibit_13_-_Exhibit_ISS-1_-_ Schedules_1.00-1.30_FINAL_REV_03-08.xlsx.

maintenance expense is reasonable because this expense varies significantly from year to year due to the cyclical nature, timing, and scope of major generation outages and the related maintenance expense.

The Commission has relied on averages of actual or adjusted actual expenses over five or more years for this purpose, in some cases, historical expenses only, and in other cases, historical and forecast expenses.

Q. Has the Company's major generation outage expense varied significantly over the last five years, including the test year?

A. Yes. However, its accounting records are not sufficiently detailed to separately quantify the major generation outage expense.[20] Nevertheless, the generation maintenance expense reached a record $87.647 million in the test year, even with a deferral of $7.244 million in Spurlock 4 maintenance expense authorized by the RUS.[21] After hitting this record in the test year, the generation maintenance expense fell to $76.334 million in 2020, a reduction of $11.313 million compared to the test year. The Company reduced the maintenance expense on all four of the Spurlock units in 2020, eight of the ten Smith CTs, and both of the Cooper units compared to the test year. The following graph provides a summary of actual generation maintenance expense for EKPC by year over the last ten years.

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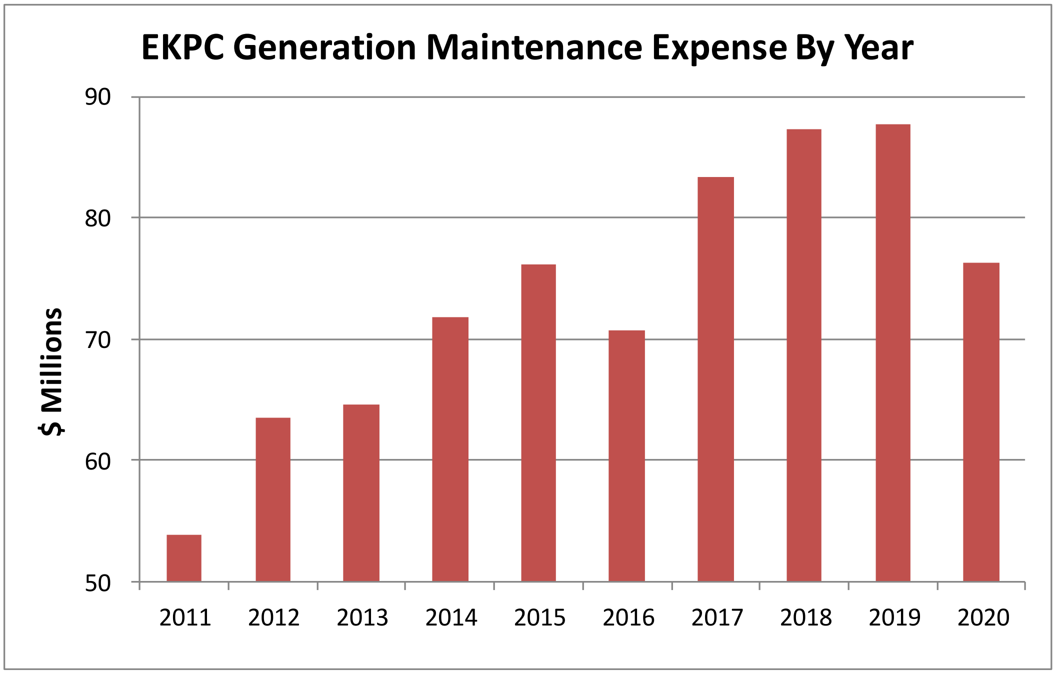
[20] Response to AG-Nucor 2-17. I have attached a copy of that response as my Exhibit___(LK-9).
[21] Response to AG-Nucor 2-19. I have attached a copy of that response as my Exhibit___(LK-10).



Q. What is your recommendation?

A. I recommend that the Commission normalize generation maintenance expense based on a five-year historic average for the years 2016 through 2020. The three years 2017 through 2019 reflect a series of increases that resulted in generation maintenance expense each year that was greater than any prior year. The years 2016 and 2020 were significantly less. As such, the most recent five-year average provides a much better measure of normalized generation maintenance expense than the all-time peak in generation maintenance expense reached in the test year.

Q. What is the effect of your recommendation?

A. The effect is a reduction in generation maintenance expense of $6.579 million.

E. Depreciation Expense

1. Description of Actual Test Year Depreciation Expense on Production Plant Accounts

Q. Describe the Company's present depreciation rates.

A. The Company's present depreciation rates were authorized in Case No. 2006-00236 and are based on a depreciation study performed by Gannet Fleming using plant in-service and accumulated depreciation amounts at December 31, 2005.[22]

The present *authorized* depreciation rates for *production* plant reflect *no* interim and no terminal (decommissioning) net salvage components.[23] The present *authorized* depreciation rates for production plant reflect forecast interim retirements based on Gannet Fleming's selection of Iowa curves used to estimate those retirements in the 2005 depreciation study. The use of forecast interim retirements in a depreciation study effectively shortens the composite remaining lives and increases the depreciation rates for the relevant plant accounts, in this case, the production plant accounts.

Q. Did the Company actually use the authorized depreciation rates for production plant after they were approved, and more importantly, did it use those rates in the calculation of the actual depreciation expense in the test year?

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[22] Response to AG-Nucor 1-25, which included a link to the depreciation study filed in Case No. 2006-00236.

[23] Response to AG-Nucor 2-7. I have attached a copy of this response as Exhibit___(LK-11).

A. No. The Company did not use the authorized depreciation rates for the calculation of actual depreciation expense in the test year. The Company was asked this question and responded as follows.

> **<u>Request 2-7.</u>** Describe how the Company calculated depreciation expense on production plant for accounting and ratemaking purposes prior to the 2006 rate proceeding. For example, for accounting purposes and in one or more rate proceedings prior to the 2006 proceeding, indicate whether the Company calculated depreciation expense on production plant as the net book value divided by the remaining months of service based on the probable retirement date. If so, identify the last rate proceeding that it relied on that calculation methodology and indicate when it changed to the present calculation of multiplying the gross plant times the approved depreciation rates for accounting and ratemaking purposes.
>
> **<u>Response 2-7.</u>** It is important to note that EKPC is only now, as part of this rate case proceeding, proposing to use a calculation whereby the original cost of the assets will be multiplied by the approved depreciation rates to determine depreciation expense for accounting and ratemaking purposes. This methodology, as fully described in the direct testimony of Mr. Spanos, incorporates both service lives and net salvage into the depreciation rates. From 2006 through current, EKPC has used the probable retirement dates of production plant to determine depreciation. In a previous EKPC rate case (Case No. 2006-00472), Exhibit F, Schedule 8, Page 1 explains that EKPC used the probable retirement dates reflected in the December 31, 2005 depreciation study approved in Case No. 2006-00236 for production plant.

In its 2019 Annual Report, the Company stated that "The production plant assets are depreciated on a straight-line basis from the date of acquisition to the end of life of the respective plant, which ranged from 2030 to 2051 in 2019 and 2018."[24]

In other words, the Company calculates depreciation expense on the production plant accounts by dividing the net book value in the numerator by the remaining months until the probable retirement date for the specific generating unit

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[24] EKPC 2019 Annual Report at 45. I have attached a copy of this page as my Exhibit___(LK-12). This page was provided in the Application at Exhibit 35 – Attachment 1 at page 46 of 79.

in the denominator.

Q. Why is that fact significant in this proceeding?

A. It is significant because the Company does not actually use the *authorized* depreciation rates for the production plant accounts, although its witness in the prior rate proceeding filed testimony that it planned to do so when base rates were reset in that proceeding.[25]

It also is significant because the Company is seeking a series of significant changes in the methodology used in the study to develop the proposed depreciation rates in this proceeding compared to the present methodology actually used to calculate depreciation expense, none of which were identified as changes in the Company's depreciation study or in the testimony of the Company's witness, Mr. John Spanos.

The actual depreciation expense recorded in the test year and in prior years did not include forecast interim retirements or forecast net salvage. To the extent the Company actually incurred interim retirements or interim net salvage, the actual retirements and net salvage were reflected in the net book value used in the numerator of depreciation expense calculation and addressed in that manner.[26]

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[25] Direct Testimony of Frank Oliva at 12-13 in Case No. 2010-00167.

[26] Retirements are reflected as reductions to gross plant and accumulated depreciation of equivalent amounts, essentially leaving the net book value as an asset amount in the accumulated depreciation. Thus, the actual net book value in the numerator of the depreciation expense calculation includes the remaining net book value of the retired plant and depreciates it over the remaining life reflected in the denominator. Similarly, to the extent the Company incurred negative net salvage (cost of removal exceeds salvage income), the net cost is included as an asset in accumulated depreciation and increases the net book value in the numerator, which then is depreciated over the remaining life reflected in the denominator.

The Company now seeks changes to the depreciation methodology to include the effects of forecast interim retirements, which shorten the average remaining lives and increase the proposed depreciation rates, and the effects of forecast interim net salvage and forecast terminal net salvage, both of which further increase the proposed depreciation rates.

Q. Is there any reason to change the Company's actual methodology for the calculation of depreciation expense on production plant in this proceeding?

A. No. The Company's actual methodology is superior to the methodology reflected in its proposed depreciation rates. Under the Company's actual methodology, the Commission does not need to forecast or guess what the interim retirements or the interim net salvage will be in future years.

The Company's actual methodology is based on actual costs, not forecast costs, and the declining life spans based on the probable retirement dates, which effectively results in updates to its depreciation rates and depreciation expense on a real-time basis. The numerator in the calculation reflects actual plant in service less actual accumulated depreciation each month. The denominator in the calculation reflects the remaining life based on the probable retirement date. This is the same methodology required by generally accepted accounting principles ("GAAP") for all companies other than rate regulated utilities whose depreciation rates are set using forecast interim retirements and interim net salvage, and, in some cases, terminal net salvage.

The Company's actual methodology incorporates all actual interim retirements and interim net salvage that were incurred in prior years through the test year in both the plant in service and accumulated depreciation and effectively includes those actual costs in the depreciation expense over the remaining lives based on the probable retirement dates for the production plant accounts.

The Company's actual methodology does not include and never has included recovery of forecast terminal net salvage. Nor did Gannet Fleming propose that forecast terminal net salvage be included in the depreciation rates for production plant in its last depreciation study, the rates the Commission authorized in Case No. 2006-00236, but were not actually used by the Company.

Q. How will the terminal net salvage be recovered if it is not included in the depreciation rates in this proceeding?

A. As a foundational matter, the terminal net salvage (decommissioning) is not incurred until after the production plant is retired. It is not incurred while the generating unit is still in operation. If the terminal net salvage is not included in the depreciation rates, then it will be recovered after the production plant is retired. This is the same assumption regarding recovery that is reflected in the Company's actual methodology and the same assumption that was reflected by Gannet Fleming, Mr. Spanos' firm, in the prior depreciation study.

This is the same approach that the Commission adopted for KPCo in Case No. 2014-00396 to recover the costs of the coal-fired assets at Big Sandy 1 when they were retired and the coal-fired Big Sandy 2 when it was retired. This is the same approach reflected in the settlement agreement between KU and LG&E and the intervenors that presently is pending before the Commission in Case Nos. 2020-00349 and 2020-00350. For these three utilities, the net book value of the retired plant costs is or will be included in a rider (KPCo Decommissioning Rider and KU and LG&E Retired Asset Recovery Rider), along with the actual decommissioning costs after they are incurred, and then recovered on a levelized, or annuitized basis, over a specified recovery period.

Q. Why is the recovery of actual terminal net salvage after the production plant is retired superior to the recovery of the forecast costs over the remaining lives of the assets?

A. There are several reasons. First, only the actual costs incurred are subject to recovery through a rider. There is no need to forecast or guess what the costs will be. In this case, Mr. Spanos used unsourced estimates of the dollars per kW cost to forecast the terminal net salvage cost, which he then escalated for inflation, but with no offset for future improvements in decommissioning methods or gains in productivity. The Company repeatedly cited its use of a historic test year for its unwillingness to provide certain forecast information in response to AG-Nucor discovery; nevertheless, and contrary to its repeated refusals to provide certain other forecast information, the Company proposes to include an amortization of forecast decommissioning costs that are unknown and uncertain and that will not be incurred for decades into the future.

Second, the recovery of the actual decommissioning costs incurred after the plant is retired can be structured in order to minimize the ratemaking effects on customers. This can be done by levelizing (annuitizing) the recovery in the same manner as a home mortgage loan is paid off and by setting the recovery period at an appropriate duration sufficient to achieve this objective.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed depreciation rates for production plant and instead authorize the Company to continue to use the methodology that it presently uses for depreciation expense on production plant rather than setting specific depreciation rates. I also recommend that the Commission maintain the status quo and deny recovery of future forecast decommissioning expense. Instead, I recommend that it address decommissioning costs if and when they are incurred in future ratemaking proceedings, perhaps through a rider in the same manner than KPCo recovers the decommissioning costs for the retired coal-fired Big Sandy 1 and Big Sandy 2 generating units and in the same manner that KU and LG&E will recovery the decommissioning costs for certain of their coal-fired generating units after they are retired if the Commission approves a settlement on those issues in their pending rate cases. Finally, I subsequently address and make additional recommendations that will affect the probable retirement dates and the remaining lives used in the calculations of depreciation expense on production plant after the Commission issues its order in this proceeding.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $12.063 million in depreciation expense if the forecast interim retirements, forecast interim net salvage, and forecast terminal net salvage are removed from the proposed depreciation rates.

Q. Is there a problem in the interim retirement data relied on by Mr. Spanos that should be corrected if the Commission does not adopt your recommendation?

A. Yes. The interim retirement data relied on by Mr. Spanos reflects unusually high interim retirements related to the major turbine overhaul on Spurlock 4 in 2019. In conjunction with that overhaul, the Company recorded plant retirements of $73.776 million in 2019.[27] In contrast to the retirements, the Company recorded plant additions of $24.750 million, which includes the costs of the cancelled Smith 1 assets that were used and removed from the Smith 1 regulatory asset.[28] Mr. Spanos assumed that the $73.766 million in interim retirements would repeat itself in his selection of the Iowa curves used for the interim retirements on the Spurlock 4 production plant accounts. This resulted in excessive forecasts of interim retirements and incorrectly inflated the proposed depreciation rates on the Spurlock 4 production plant accounts.

Q. What is your recommendation?

A. I recommend that the Commission reject the Company's proposed depreciation

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[27] Response to AG-Nucor 1-29. I have attached a copy of this response as Exhibit___(LK-13).

[28] Response to AG-Nucor 2-16(d)(iv). I have attached a copy of this response as Exhibit___(LK-14).

rates on the production plant accounts and direct the Company to calculate depreciation expense in the same manner that it has historically, in which case the Spurlock 4 interim retirements issue is irrelevant. However, if the Commission sets new depreciation rates on the production plant accounts that reflect forecasts of interim retirements and effectively shorten the remaining lives for depreciation expense purposes, then I recommend that it direct the Company to modify the Spurlock 4 interim retirements to exclude the excessive interim retirements by setting them at the same level as the plant additions related to the overhaul in 2019.

2. Smith CT Life Spans (Units 1-3 from 35 Years to 45 Years and Units 4-10 from 40 Years to 45 Years)

Q. Describe the life spans for the Smith CTs reflected in the proposed depreciation rates.

A. The Company proposes probable retirement dates that reflect life spans of 35 years for Smith Units 1-3 and 40 years for Smith Units 4-10.[29]

Q. Are these life spans reasonable?

A. No. First, the life spans are assumptions regarding the future continued operation and maintenance or retirement of these CTs; the life spans are not known facts and are not based on specific planned or certain retirement dates. The Company does not have actual plans to retire the units on those dates. To the contrary, the

[29] Exhibit JJS-1 page 38 of 245.

Company will continue to operate and maintain those units until they no longer are economic. As a member of PJM, EKPC's CTs, even older less efficient ones, can be a valuable capacity resource even if they are higher cost to actually operate.

Indeed, the Company has a history of extending the life spans and the probable retirement dates of its generating units, most notably in Case No. 2006-00236, wherein it presented its most recent depreciation study until this proceeding, and which the Commission relied on to quantify the depreciation expense included in the base revenue requirement in Case No. 2006-00472. The depreciation study and the revised "depreciation end dates" were the result of a settlement in Case No. 2004-00321 in response to an intervenor's claim that the Company's life spans used for depreciation purposes were inordinately short, the same issue in this proceeding.

More specifically, in Case No. 2006-00236, Company witness Ms. Ann Wood presented a table comparing the "current depreciation end date" to the "proposed depreciation end date," or probable retirement dates, for each of the Company's generating units.[30] The Company proposed extensions in life spans of 8 years for Cooper, 13 years for Spurlock 1; 15 years for Spurlock 2; 8 years for Gilbert; 12 years for CT 1, 2, and 3; 14 years for CT 4 and 5; 16 years for CT 6 and 7; and 20 years for landfills. The Commission approved these extensions in life spans.

Second, the life spans for Smith Units 1-3 are not consistent with the life spans for Smith Units 4-10 and the Company has offered no valid justification to

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[30] Direct Testimony of Ann Wood at 2-3 in Case No. 2006-00236. I have attached a copy of the relevant pages as my Exhibit___(LK-15).

use two different life spans for these CTs. When asked for such justification in AG-Nucor discovery, the Company stated the following.[31]

> **Request 1-23.** Refer to Exhibit JJS-1 and the table of depreciable life spans and estimated retirement dates for each of the production plants. Explain all reasons why the depreciable life spans for Smith Unit 1, Unit 2, and Unit 3 reflect only 35-year life spans while Smith Units 4-10 all reflect life spans of 40 years.
>
> **Response 1-23.** Similar to the process for steam facilities, life spans are determined based on various factors, which include technology of the facility, management plans, outlook for the facility, type of construction, condition of the facility, regulations and estimates of similar facilities within the electric industry. For combustion turbines, life spans have generally been expected to be in the 30-40-year range; however, these units are generally peaking. Therefore, based on EKPC plans for all the Smith units, the efficiencies of the units and how each is utilized in the overall generation fleet, it is expected that Smith Units 1, 2 & 3 will be retired/rehabilitated after 35 years while the others will have a 40-year life span. Demand of these peaking units is also a consideration for these units.

When asked to provide a copy of the Company's "plans," the Company had no such plans that it could produce and Mr. Spanos simply reiterated the general description of the Company's so-called "plans" provided in the prior response.[32]

Third, the life spans for Smith Units 1-3 are not consistent with the life spans for the Bluegrass Oldham Units 1-3 CTs, which each have a proposed 40-year life span. The Company has offered no valid justification to use two different life spans for the Smith 1-3 CTs and the Bluegrass Oldham 1-3 CTs. When asked for such justification in AG-Nucor discovery, the Company stated the following.[33]

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[31] Response to AG-Nucor 1-23. I have attached a copy of this response as Exhibit___(LK-16).
[32] Response to AG-Nucor 2-14. I have attached a copy of this response as Exhibit___(LK-17).
[33] *Id.*

> **Request 2-14(b)(i).** Provide a copy of all engineering or other technical analysis that supports the use of two different life spans for similar generating units (Smith 1-3 v Smith 4-10 and Bluegrass Oldham 1-30). In addition, indicate when each such analysis was performed, the purpose for which it was performed, who developed or conducted the analysis, and the actual use of the analysis, if any, other than to support the life spans for depreciation purposes.
>
> **Response 2-14(b)(i).** There are not specific engineering or other technical analyses performed to establish a depreciable life span for combustion turbines. There were many factors that went into the analysis of the appropriate life span to use for EKPC's production facilities. These factors were discussed in the response to AG-Nucor 1-23. Examples of these key factors are: number of starts, efficiency of the units, how the unit is dispatched, and how can the unit meet the peaking demand. The current depreciation rates being utilized by EKPC are based on the same life span for each Smith Unit as recommended in this depreciation study. There haven't been any major changes to EKPC's plans related to these units that would necessitate a change in life span at this time. Retirements of these types of units happen in the 30-40 year age range, thus the 40-year life span being utilized on the newer Smith units is on the longer side of the typical industry range. Given the way EKPC utilizes Units 1-3, and the efficiencies of all the Smith units, it is expected that Units 1-3 (which were placed in service earlier than the other units) would have a somewhat shorter expected life span than the other Smith units. Units 1-3 are larger units and take longer to get to full capacity to meet the demand of peaking requirements, so they have different overhaul cycles and consequently the overall life cycle is shorter.

Fourth, the life spans are inordinately short. Other utilities have an actual history of operating and maintaining their CTs for 45 to 70 years, despite the claims in the response to the previously cited discovery response. I provided the following testimony in Duke Case No. 2019-00271 regarding the inordinately short life spans for the Woodsdale CTs.[34]

> The actual life spans of CT units that remain economic typically extend to 50 or more years. This is consistent with information for CT units publicly available from the Energy Information Administration ("EIA") through 2018 and published by the EIA in early 2019. For example, the Duke Energy Florida, LLC Avon Park CT and Higgins 1-4 CTs are projected to be retired this year and in 2020 after 48-51 years of service, according to the EIA data. The Duke Energy Florida, LLC P L Bartow 1-2 CTs have been in service for 47 years through the end of 2018 and have no planned retirement date, according to the EIA data.
>
> The Kentucky Utilities Company Haefling 1 and 2 CTs have been in service for 49 years through the end of 2018 and have no planned retirement dates, according to the EIA data. The Louisville Gas & Electric Company ("LG&E") Cane Run 11 CT and Paddy's Run 11 and 12 CTs have been in service for 51 years through the end of 2018 and have no planned retirement dates, according to the EIA data. The LG&E Zorn 1 CT has been in service for 50 years through the end of 2018 and has no planned retirement date, according to the EIA data.
>
> The Southern Indiana Gas & Electric Company Northeast 1 and 2 CTs have been in service for 56 and 55 years, respectively, through the end of 2018 and will be retired in 2019, which will result in actual service lives of 57 and 56 years, respectively, according to the EIA data.

Q. What is your recommendation?

A. I recommend that the Commission adopt a consistent life span of at least 45 years for all ten Smith CTs and reflect this consistent life span in the probable retirement dates for all ten Smith CTs. The 45 years is at the lower end of the range of actual experience across the industry, including the actual life span experience of CTs owned and operated by utilities in Kentucky.

I also recommend that the Commission direct the Company to use these

[34] Direct Testimony of Lane Kollen at 55-56. Mr. Kollen relied on the following information source in that proceeding: EIA Form 860 survey data regarding existing and planned generators and associated environmental equipment at electric power plants. https://www.eia.gov/electricity/data/eia860/.

revised probable retirement dates in the calculation of depreciation expense regardless of whether the Commission affirms and directs the Company to continue using its historic methodology for calculating depreciation expense in real time or whether it revises and directs the Company to use specific depreciation rates for the production plant accounts when it resets base rates in this proceeding.

Q. What is the effect of your recommendation?

A. The effect is a reduction in depreciation expense of $2.118 million. This effect is in addition to the effect of my prior recommendation to direct the Company to continue using its historic methodology for calculating depreciation expense on the production plant accounts.

3. Bluegrass Oldham CT Life Spans

Q. Describe the life spans for the Bluegrass Oldham CTs reflected in the proposed depreciation rates.

A. The Company proposes probable retirement dates that reflect life spans of 40 years for Bluegrass Oldham Units 1-3.

Q. Are these life spans reasonable?

A. No. As I noted with the Smith CTs, the life spans are assumptions and the Company has provided no valid justification in support of these assumptions for the Bluegrass Oldham 1-3 CTs. Other utilities have operated and maintained their CTs for 45 to 70 years. The Company will continue to operate the Bluegrass Oldham CTs indefinitely as long as it is economic to do so.

Q. What is your recommendation?

A. I recommend that that the Commission adopt the same life span of at least 45 years for all three Bluegrass Oldham CTs, the same minimum life span that I recommend for all ten Smith CTs, and reflect this life span in the probable retirement dates for all three Bluegrass Oldham CTs. I also recommend that the Commission direct the Company to use these revised probable retirement dates in the calculation of depreciation expense regardless of whether the Commission affirms and directs the Company to continue using its historic methodology for calculating depreciation expense in real time or whether it revises and directs the Company to use specific depreciation rates for the production plant accounts when it resets base rates in this proceeding.

Q. What is the effect of your recommendation?

A. The effect is a reduction in depreciation expense of $0.719 million. This effect is in addition to the effect of my prior recommendation to direct the Company to continue using its historic methodology for calculating depreciation expense on the production plant accounts.

4. General Plant Reserve Surplus

Q. Describe the Company's proposed amortization of the general plant depreciation reserve surplus.

A. The Company proposes negative $1.910 million in amortization expense to reflect a ten-year amortization of the $19.103 general plant depreciation reserve surplus.

Q. Do you agree with the Company's proposed ten-year amortization period?

A. No. The amortization period is a matter of informed judgment, but the ten-year amortization period is inordinately long. To the extent there is an overrecovery in prior years, as is the case here, then it should be returned expeditiously to customers, especially within the context of a requested base rate increase.

Q. What is your recommendation?

A. I recommend a five-year amortization period. In this case, a five-year amortization period provides a reasonable balance between the magnitude of the overrecovery and the expeditious return to customers.

F. <u>Cancelled Smith 1 Regulatory Asset Amortization Expense</u>

Q. Describe the Company's cancelled Smith 1 regulatory asset and the proposed amortization expense.

A. The Company proposes an amortization expense of $13.947 million based on a proforma regulatory asset of $73.221 million at December 31, 2019 using a 63-month amortization period starting on October 1, 2021, the approximate effective date of new rates in this proceeding.[35]

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[35] Tab 1.20 - Amort of Smith 1 on Application_Exhibit_13_-_Exhibit_ISS-1_-_Schedules_1.00-

Q. Is the adjusted proforma $73.221 million the same as the actual amount recorded on the Company's accounting books at December 31, 2019?

A. No. The actual balances on the Company's accounting books are $88.847 million at December 31, 2019, $64.797 million at December 31, 2020, and $60.884 million at April 30, 2021.[36] The actual balance will be even less at October 1, 2021. The Company has amortized the Smith 1 regulatory asset on a straight-line basis starting January 2017 over ten years on its accounting books and continued to do after December 31, 2019.

The reason for the differences between the proforma regulatory asset and the actual balances on its accounting books is that it has separately calculated the proforma amount of the regulatory asset based on its interpretation of Section 1.2.5 of the Stipulation Agreement approved by the Commission in Case No. 2015-00358 for ratemaking purposes.[37] The Stipulation Agreement addressed how EKPC was to determine the Smith 1 regulatory asset and the amortization expense to request in its next general base rate proceeding. Section 1.2.5 of the Stipulation states the following.

> As part of its next general base rate proceeding, EKPC shall request that its rates be adjusted to reflect the amortization expense of the Smith 1 Regulatory Asset. This amortization adjustment shall be spread over the remaining months of the 10-year amortization period that began on January 1, 2017, and shall be based on the Smith 1 Regulatory Asset balance as of

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1.30_FINAL_REV_03-08.

[36] Response to AG-Nucor 1-20 page 5 of 10 (account 182306). I have attached a copy of this response as my Exhibit___(LK-18).

[37] Response to AG-Nucor 2-33. I have attached a copy of this response as Exhibit___(LK-19).

> January 1, 2017, reduced by: (i) the actual results of EKPC's mitigation and salvage efforts during the period of January 1, 2017, through the end of the test year employed in the rate case; and (ii) the Net PJM Capacity Market Benefit earned by EKPC beginning with the 2016/2017 PJM Delivery Year and concluding at either the end of the test year employed in the rate case or the end of calendar year 2019. This latter determination shall be made depending on whether, at the time of EKPC's next general base rate proceeding, the PJM Capacity Market Costs associated with calendar year 2019 are known and measurable. If they are, EKPC shall request an amortization adjustment that reflects the full Net PJM Capacity Market Benefit realized through 2019. . . For cost of- service purposes, the amortization expense of the Smith 1 Regulatory Asset will be treated like other capacity related costs (e.g., power plant depreciation).

The Company calculated no amortization of the regulatory asset from January 1, 2020 through September 30, 2021, essentially placing it on hiatus for 21 months for ratemaking purposes, although it did make adjustments for the reclassifications of certain costs to inventory and other lesser adjustments that were recorded in 2020. It then determined there were 63 months remaining for the proforma amortization expense starting with October 2021 and continuing through December 2026.

Q. Do you agree with the amount of the Company's proposed amortization expense?

A. No. The Stipulation defines how the regulatory asset is to be calculated as of December 31, 2019 and the calculation of the amortization expense based on the remaining months from January 2020 through December 2026 for ratemaking purposes, or a period of 84 months; it does not define the calculation of the amortization expense based on the remaining months from October 2021 through

December 2026 as proposed by the Company.

Q. What is your recommendation?

A. I recommend that the Commission utilize an amortization period of 84 months for the amortization expense and the ratemaking recovery.

Q. What is the effect of your recommendation to use an 84-month amortization and recovery period?

A. The effect of my recommendation is a reduction in the amortization expense of $3.487 million.

IV. INTEREST EXPENSE

A. <u>Interest Expense and TIER on Debt Used to Finance Short-Term Investment Portfolio</u>

Q. Describe the relationship between the Company's utility investment, or rate base, and its capitalization, or members' equity, and its long-term and short-term debt.

A. As a cooperative, the Company finances all of its assets, less all of its liabilities (net assets) through members' equity, long-term debt, and short-term debt. The Company's rate base is the subset of the assets and liabilities used to measure the utility investment that provides electric service to its customers.

Regardless of the assets and liabilities recorded for accounting purposes, the

Company is entitled only to recover the interest expense incurred to finance utility investment that provides electric service to its customers and the related TIER through the ratemaking process. The Company is not entitled to recover the interest expense incurred to finance non-utility investments and a related TIER through the ratemaking process unless there is interest income that exceeds the interest expense and related TIER. The same standard is applicable to both cooperative and investor-owned utilities. The same standard is applicable for both base and rider ratemaking purposes. For example, the Company is entitled only to recover interest expense and the related TIER on its authorized environmental utility investment, or rate base, through the ES.

Q. Why is this standard important in this proceeding?

A. It is important because there is a significant mismatch between the Company's utility investment and its total capitalization due to its extremely significant short-term investment portfolio that has minimal interest income. Unlike its former investments pursuant to the RUS Cushion of Credit program where it earned more interest income than it incurred in interest expense, this type of investment program is a net loser and imposes an unnecessary and unreasonable cost on customers to the extent the interest expense, related TIER, and interest income are included in the revenue requirement. Unlike the RUS Cushion of Credit program, which made money, this is a negative arbitrage opportunity, which loses money.

The Company included $4.160 million in interest expense on the debt outstanding that it used to finance its short-term investment portfolio and the related

TIER in the claimed base revenue deficiency. It also included $0.255 million interest income on the investment portfolio.[38] However, the interest income included in the claimed base revenue deficiency doesn't even come close to the interest expense on the debt used to finance the portfolio. Even if the interest income on the investment portfolio were the same as the cost of debt used to finance the portfolio, there still would be a cost to customers from the TIER on the interest expense because there is no TIER on the interest income.

Q. What is the magnitude of the Company's short-term investment portfolio?

A. The Company included $111.000 million in short-term temporary investments ("available for sale securities") at June 30, 2020, the date it chose to calculate the interest expense and TIER reflected in its claimed revenue deficiency.[39] The Company chose this date in order to reflect the unwind of the RUS Cushion of Credit investments and the use of those proceeds to redeem outstanding long-term debt. In effect, the Company revised its test year, at least for the calculation of interest expense and TIER, from calendar year 2019 to the twelve months ending June 30, 2020.

Q. Is the Company's short-term investment portfolio financed by members'

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[38] Refer to cells H13, H16, and H17 on Sch 1.05 Interest Income for the normalized interest income on the short-term investment portfolio included in the claimed base revenue requirement.

39 Refer to the Company's proforma balance sheet at Application_Exhibit_13_-_Exhibit_ISS-2_-_Balance_Sheet_-_FINAL, which reflects the test year balance sheet after proforma adjustments, including the unwind of the RUS Cushion of Credit program.

equity?

A. No. The Company's short-term investment portfolio is not financed by members' equity. It is financed by long-term debt.[40] This is illustrated by the simple fact that the Company could have and still is able to use the cash from selling these short-term investments to redeem additional long-term debt in the same manner that it redeemed the long-term debt used to finance its investments under the RUS Cushion of Credit program. In fact, Mr. Stachnik notes that rating agency Fitch relies on a financial metric that reflects "Net Debt," defined as total debt minus cash equivalents and short-term investments, as follows.

> Financial Profile: Fitch places heavy emphasis on one ratio, Net Adjusted Debt to 6 Adjusted FADS. Net Debt is Total Debt minus cash equivalents and short-term investments (including the RUS Cushion of Credit).

I note this primarily to make the point that this further demonstrates that there is no merit to any claim that the short-term investment portfolio is financed by members' equity. In addition, I note this to make the point that Fitch assumes also that the Company's cash equivalents are financed with debt, not members' equity.

Q. Is the Company required to maintain this short-term investment portfolio to provide utility service?

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[40] The Company claims that its short-term investments were not "financed" in response to AG-Nucor 2-21(c). This claim is patently incorrect. By definition, the balance sheet always has to balance. Total assets always equal total liabilities plus members' equity, long-term debt, and short-term debt. This is shown quite clearly on the Company's proforma balance sheet at Application_Exhibit_13_-_Exhibit_ISS-2_-_Balance_Sheet_-_FINAL.

A. No. None of the short-term investments are required to provide utility service or to maintain an investment grade credit rating. In fact, if the Company sold its short-term investment portfolio and redeemed an equivalent amount of long-term debt, all of its relevant credit metrics (members' equity ratio, TIER, DSC, and MFIR) would improve. The members' equity ratio would increase because the dollars in the numerator would remain the same, but the total financing in the denominator would be less. The TIER, DSC, and MFIR would increase because the interest expense in the denominators of these ratios would be less.

Q. How does the Company's short-term investment portfolio compare to the short-term investments held by other electric utilities in the Commonwealth?

A. It is significantly excessive. Duke (electric and gas) had a total of $0, KPCo had $0, KU had $2.286 million, LG&E had $6.827 million, and BREC had $39.212 million in short-term investments held at December 31, 2019.[41]

Q. Does the Company have a credit facility that can be and is used for short-term cash requirements and to maintain liquidity?

A. Yes. The Company has a $600 million credit facility with CFC as the lead arranger.[42] The Company reflected the interest expense and TIER on $185.000

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[41] Annual Reports for 2019 filed with the Commission by each utility. BREC had $27.000 million in cash general funds and temporary cash investments at December 31, 2020 based on its Annual Report for 2020 filed with the Commission. I have attached excerpted pages from each of those filings as my Exhibit___(LK-20).

[42] Refer to the Company's 2020 Annual Report at 67. I have attached a copy of this page as my Exhibit___(LK-21).

million in outstanding draws against the facility in its claimed revenue deficiency.

Q. **Why is that significant?**

A. The credit facility provides access to a high level of credit and liquidity, negating the need to maintain short-term investments above and beyond its extremely high cash general funds, which also provides a high level of liquidity. The Company also maintains a high level of cash general funds. It had $19.8 million in cash general funds at December 31, 2019 and $36.2 million at June 30, 2020.[43,44] The cash general funds also provide liquidity.

Q. **Is it reasonable to include the interest expense on the debt necessary to finance $111.000 million in short-term investments?**

A. No. The short-term investment portfolio is not necessary for the provision of utility service or to maintain credit metrics necessary for an investment grade credit rating. The Company's portfolio is excessive when compared to other utilities in the Commonwealth.

Q. **What is your recommendation?**

A. I recommend that the Commission exclude the interest expense and TIER on the Company's and the interest income on the short-term investment portfolio from the base revenue requirement.

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[43] Response to AG-Nucor 1-3.
[44] Response to AG-Nucor 2-8.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $6.252 million in the claimed revenue deficiency, consisting of a reduction of $4.160 million in interest expense, a reduction of $2.079 million in the related TIER, and a reduction of $0.013 million in the gross up for PSC fees.

B. <u>Interest on Debt Used to Finance Environmental Surcharge Projects</u>

Q. Describe the Company's adjustment to remove the interest expense for the ES investment, or rate base, from the total Company interest.

A. The Company removed $24.035 million in interest expense for the ES investment from the total Company interest expense included in the claimed base revenue deficiency. The reduction in interest expense for the ES investment also effectively removed $12.018 million in TIER from the claimed base revenue deficiency.

The Company determined the interest related to the ES based on a direct assignment of debt issued specifically to finance individual ES projects. On this basis, the Company simply assumed that there was no debt and no interest expense related to the projects that were under construction included in the ES, effectively retaining the interest expense in the claimed base revenue deficiency.[45]

[45] Response to AG-Nucor 2-28. I have attached a copy of that response as my Exhibit___(LK-22).

Q. How does the interest expense removed from the total Company interest for the ES compare to the actual interest recovered in the ES in the test year?

A. It is less than the actual interest recovered in the ES in the test year.

Q. Why is it less?

A. It is less because the Company actually recovers interest expense and TIER on construction work in progress in the ES. The CWIP is included in rate base and the return is applied to the rate base. The Company's claim that it does not recover interest expense on CWIP in the ES is incorrect and contradicts its stated intent to recover the interest expense during construction in its Application for a CPCN and ES recovery on the CCR/ELG project in Case No. 2017-00376. In its Application in the CPCN proceeding, the Company stated the following:

> 49. . . . EKPC intends to finance the construction of the CCR/ELG Project through its existing credit facility before transitioning it to a long-term debt placement available through its Trust Indenture.
>
> 50. Under KRS 278.183(2), EKPC is entitled to earn a return on its investment. The original (and still used) methodology for determining an appropriate return is the product of the weighted average debt cost of the debt issuances directly related to the projects in EKPC's Compliance Plan, multiplied by a Times Interest Earned Ratio ("TIER") factor.

Q. Is it appropriate to retain the interest and TIER related to the CWIP in the ES in the base revenue requirement?

A. No. The Company is not entitled to recover interest on the same rate base investment in the ES and the base revenue requirement. The projects under construction and included in the ES require an allocation of the outstanding debt and related interest expense. This is necessary for two reasons. First, the Company actually does recover interest on CWIP in the ES. Second, even if that were not true, then the Company will recover the interest expense and TIER on the CCR/ELG projects not only during the construction period in the base revenue requirement, but also after the projects are placed in service and financed through long-term debt available through its Trust Indenture in the ES. In other words, if construction period interest and TIER are included in base rates in this proceeding, then there will be a double recovery once construction is completed and full recovery of the completed CCR/ELG is achieved through the ES. The allocation of the interest on the CCR/ELG project to the ES is necessary to avoid a double recovery between the base revenue requirement and the ES revenue requirement.

Q. What is your recommendation?

A. I recommend that the Commission remove the interest expense and TIER related to the ES CWIP projects from the base revenue requirement. The Company sought and was authorized recovery of the construction period interest expense in the ES on these projects, and that is how the cost should be tracked and recovered until the CCR/ELG goes commercial. The Commission should not include this interest expense and TIER in the base revenue requirement.

Q. What is the effect of your recommendation?

A. The effect is a reduction of $8.551 million in the claimed base revenue deficiency, consisting of a reduction of $5.689 million in interest expense, a reduction of $2.845 million in the related TIER, and a reduction of $0.017 million in the gross up for PSC fees.

V. TIMES INTEREST EARNED RATIO

A. A TIER of 1.50X Is Excessive Compared to Requirements Under Loan Agreements

Q. Describe the Company's TIER request.

A. The Company's claimed base revenue requirement includes $67.557 million in interest expense and $33.779 million in TIER at the proposed 1.50X. The ES includes $24.035 million in interest expense and $12.018 million in TIER at the proposed 1.50X. In other words, the Company seeks recovery of $45.797 million for its proposed TIER at 1.50X for a cost that it doesn't actually incur, but which provides it a margin in addition to the costs that it does incur and allows it to continue increasing its members' equity, all else equal, and assuming no future capital credits.

After the adjustments to interest expense that I recommend, the base revenue requirement includes $57.709 million in interest expense and $28.855 million in TIER and the ES revenue requirement includes $29.724 million in interest expense and $14.862 million in TIER, both at the Company's proposed TIER of 1.50X.

After the adjustments to interest expense that I recommend, a change of

0.10X in TIER is equal to $5.782 million in the base revenue requirement and $2.978 million in the ES revenue requirement.

Q. Is a TIER of 1.50X necessary for the Company to meet its loan covenants?

A. No. The Company must meet an MFIR of 1.10X under the terms of its credit facility every year. The Company is subject to a separate requirement that rates be set at a minimum MFIR of 1.10X under an Indenture applicable to its secured debt agreements for the RUS/FFB debt, Private Placement loans, and CFC loans, although it does not result in an immediate default if the Company fails to meet the covenant in a single year. The MFIR of 1.10X is equivalent to a TIER of 1.10X.[46]

In addition to the Indenture, there are separate loan agreements with RUS, CFC, and the Private Placement Holders. Some of these agreements include additional covenants (such as a requirement in the CFC loan agreements to maintain a DSC of 1.05X for two out of every three years), but none of them are as stringent as the one in the Credit Facility.[47]

Q. What is the significance of the credit facility, Indenture, and other loan agreement requirements?

A. None of the agreements require a TIER of 1.50X. A TIER of 1.30X would provide a significant margin above the credit facility, Indenture, and other loan agreement requirements.

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[46] Direct Testimony of Thomas Stachnik at 17.
[47] *Id.*

<u>B. A TIER of 1.50X Is Not Necessary to Maintain Investment Grade Credit Ratings</u>

Q. Describe the Company's financial condition and other circumstances at the time of its last base rate case proceeding in 2010 when the Commission allowed a TIER of 1.50X.

A. In Case No. 2006-00472, the Commission granted EKPC a TIER of 1.35X. According to EKPC, the "calculated" TIER from the settlement agreement in Case No. 2008-00409 yielded a TIER of 1.38X. In Case No. 2010-00167, the Commission granted EKPC a TIER of 1.50X. However, that TIER was specifically premised on the findings and recommendations from the Focused Management Audit of EKPC conducted for the Commission by the Liberty Consulting Group.

The Commission retained Liberty Consulting because EKPC's financial condition was precarious including a very low equity ratio that needed to be increased through higher margins which a TIER of 1.50X would produce. "The Commission has found that EKPC's proposed TIER of 1.50 is reasonable in light of the findings and recommendations contained in the Liberty Report."[48] Liberty summarized EKPC's "financial crisis" from 2006-2008 as follows.[49]

- Technical defaults on the RUS mortgage agreement arising from the failure to meet financial covenants

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[48] Case No. 2010-00167 Order at 19.
[49] Liberty Report at 26.

- Forced amendment of the $650 million credit facility covenants with private lenders to prevent a default
- The Commission financial investigation, which expressed concerns regarding EKPC's financial viability
- EKPC's request for emergency interim rate relief in 2007 to avoid additional defaults on loan agreements
- EKPC's October 2008 request for the treatment of forced outage costs as a regulatory asset to avoid yet another potential default on the private credit facility.

The Liberty Report found that from 2003 to 2008, EKPC's equity ratio had fallen from 12.61% to 6.75%. To address this serious problem, Liberty made numerous recommendations, among which was to "adopt capital structure and financial performance targets that ensure financial strength and access to the capital markets," including increasing its equity level to 20% or more.[50]

It was in this extraordinary context that the Commission established a TIER of 1.50X in Case No. 2010-00167.

Q. Is the Company in the same financial condition and circumstances today that it was in 2010?

A. No. The Company is now in a very healthy financial condition. It has an A rating from S&Ps with a stable outlook and a BBB+ rating from Fitch, also with a stable outlook. At the end of 2020, EKPC achieved an equity ratio of 21.2% ($744.3 million). EKPC's bylaws permit it to retire capital credits when, after any proposed

[50] I have attached the Introduction and Recommendations sections of the 2010 report as my Exhibit___(LK-23) for ease of reference.

retirement, its total equity exceeds 20% of total assets. Due to its strong financial condition, EKPC refunded patronage capital (capital credits) of $1.8 million in 2019 for the first time in its history and another $6.0 million in 2020.

Q. Is EKPC structurally less risky today because of Commission mandated changes to its all requirements contract with its sixteen members than it was in 2010 when the TIER of 1.50X was authorized?

A. Yes. EKPC's relationship with its sixteen Member-Owners is fundamentally less risky today than it was when the TIER of 1.50X was awarded. In 2003, EKPC's wholesale power contract with its sixteen Member-Owners was modified to allow the Members to purchase limited quantities of power from alternative sources ("Amendment 3"). The wholesale power contract was modified again in 2015 in a Memorandum of Understanding (MOU) to clarify the allocation provision of Amendment 3. Amendment 3 and the MOU caused severe disagreement and acrimony between EKPC and its Members when one member tried to purchase 58 MW from Morgan Stanley Capital Group, with EKPC's associated fixed generation costs shifted to the other fifteen members. The Commission put an end to that. "Thus, from the date of the entry of this Order, the alternative source provisions in Amendment 3 and the MOU are stricken from EKPC's tariff and no further alternative source elections are permissible."[51] The Commission's termination of Amendment 3 fundamentally reduced EKPC's risk.

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[51] Case No. 2018-00050 Order at 38.

The importance of this Commission decision was recognized by Fitch when it reaffirmed EKPC's investment grade credit rating in June 2020. "EKPC's revenue source characteristics are very strong. The wholesale power agreements extend through Jan. 1, 2051 and require members to serve their entire load through purchases from EKPC. The agreements were reaffirmed following an order by the PSC in September 2018 nullifying parts of the 2003 amendment, which previously allowed members to purchase off-system power up to 15% of their three year average rolling peak as long as it did not exceed 5% of EKPC's peak demand. The PSC order also prohibited any future efforts by members to purchase power from suppliers other than EKPC. Fitch believes the PSC decision strengthens EKPC's revenue source characteristics and mitigates the need for EKPC to reallocate fixed costs resulting from lost member load."

Q. Is a TIER of 1.50X necessary for the Company to maintain its healthy financial condition and investment grade debt ratings?

A. No. The Company presently targets a TIER of 1.20X to 1.50X, with a midpoint of 1.35X.[52] The Company's average actual earned TIER in the years 2016 through 2020 was 1.34X.[53] This demonstrates that a TIER of 1.50X is not necessary for EKPC maintain its healthy financial conditions and investment grade debt ratings, and to continue growing its equity ratio. It also demonstrates that a TIER of 1.30X will allow the Company to retain its present investment grade debt ratings if it is

[52] Direct Testimony of Ann Bridges at 4.
[53] Refer to Stachnik Exhibit TJS-2.

able to actually earn the allowed TIER.

Q. What are EKPC's future margin (TIER) prospects?

A Since this is not a forecasted test year, that is somewhat hard to predict. But the Company's prospects look strong. Even in the pandemic 2020 year it earned a TIER of 1.28X. EKPC's 2019 Annual Report notes the significant progress it has made in economic development recruitment efforts. "Competitive co-op rates have enabled Kentucky's Touchstone Energy Cooperatives to bring new jobs and investments to their service territories. The economic development team worked closely with state leaders and global businesses that announced projects worth nearly $468 million in new investments during 2019. These projects will create 1,551 jobs and build new facilities that will improve the quality of life for many people in the areas served by our owner-members."

In late 2021, Nucor expects to finish its $650 million plant expansion that will double its steel making capability. The plant expansion will double its demand from about 200 MW to about 400 MW. Increased energy usage will be about 1 million MWh per year, which represents about a 7.5% increase in EKPC retail sales. EKPC will earn additional margins from increased demand charges, increased energy charges (which recover fixed costs) and from sales of Nucor's interruptible load into the PJM capacity markets. All consumers will see an immediate rate reduction in their ES as the same fixed environmental costs are amortized over more sales. EKPC also will benefit from the economic growth caused by the Nucor plant expansion. Nucor witness Mr. Kornstein forecasts that the expansion will create 1,198 direct, indirect, and induced jobs, will increase Kentucky state-wide labor income by $82.8 million annually, and will create $347 million in additional annual Kentucky GDP.

C. A TIER of 1.50X Is Excessive Compared to Big Rivers

Q. What is the most recent allowed TIER for Big Rivers?

A. The Commission most recently allowed a TIER of 1.30X for Big Rivers.[54]

Q. What is the significance of the allowed TIER for Big Rivers?

A. It demonstrates that a TIER of 1.30X is reasonable. Both Big Rivers and the Company are investment rated. Both utilities have an equity to capitalization ratio that is greater than 20%. Both utilities now are financially healthy, although the Big Rivers debt rating is lower than the Company's debt rating.

D. An Excessive TIER in Rates Cannot Be Fully or Timely Remedied Through Capital Credits

Q. How does the Company's TIER request result in excessive costs to ratepayers?

A. As a foundational matter, the requested TIER of 1.50X is excessive for the reasons that I previously cited. In theory, if the Commission authorizes an excessive TIER and this results in excessive margins, they can be returned to ratepayers through

[54] Order in Big Rivers' most recent base rate proceeding, Case No. 2013-00199, at page 32. Order in Big Rivers most recent Member Rate Stability Mechanism proceeding, Case No. 2021-00061, at page 5.

capital credits. In practice, this is a flawed theory and should be rejected.

In practice, the return of the Company's excess margins through the owner/member distribution cooperatives to their customers is unlikely to occur, and if it does occur, is likely to be diluted and delayed. The Company first has to identify, quantify, and authorize capital credits to the member/owner distribution cooperatives. This is done on a vintage year, first in first out basis, and is subject to numerous restrictions, thus diluting and delaying the return of excess margins in any one year to subsequent years, most likely many years into the future.

This process is repeated at each of the distribution cooperatives, thus further diluting and further delaying the return of the Company's capital credits through the distribution cooperatives to their customers, if there are any capital credits provided at all. There is no requirement that the distribution cooperatives provide the capital credits they received from the Company to their ratepayers.

Also in practice, the collection of excessive revenues actually costs more than could possibly be returned to ratepayers even in a perfect world of regulation and timely flow through of capital credits from the Company to the distribution cooperatives and then to their customers. That is due to the fact that the distribution cooperatives are required to add and collect sales taxes of 6% on their non-residential sales and school taxes (usually 3%), which, in turn, are simply remitted to the state and local tax authorities and are unavailable for capital credits. In contrast to the collection of revenues, the cooperatives do not add sales or school taxes to capital credits.

In sum, EKPC's wholesale rates should not be set unreasonably high so that capital credits may be returned to the member/owner distribution cooperatives at diluted amounts in subsequent years, who then may dilute and delay the return of these amounts through capital credits to consumers, if they are returned at all.

E. Cooperative TIER and Investor Owned Utility ROE Are Not Comparable

Q. Please respond to the Company's attempt to justify a 1.50 TIER by converting TIER into return on equity (ROE) for an investor owned electric utility.[55]

A. This is a misleading comparison that has no relevance in setting cost-based rates for a G&T cooperative. The cooperative business model is inherently different than the investor owned utility business model.

In the EKPC business model, there are two levels of customer supplied member equity. First, customers supply member equity to support the operations of their distribution cooperative. Then, the distribution cooperatives invest a portion of their member equity to support the operations of EKPC. The Company's attempt to convert EKPC's TIER into an equivalent investor owned electric utility ROE ignores these member equity investments in both their distribution cooperatives and in EKPC, which results in an incomplete and misleading comparison.

The member-owners have invested their own money in EKPC through direct capital investment and through the margins included in their G&T rates.

55 Direct Testimony of Thomas Stachnik at 21-23.

Each member-owner has its own cost of capital for its share of member equity. For example, the cost of capital to a residential customer who carries a credit card balance might be 18%. Each member-owner "earns" a return on its investment through avoided interest expense on avoided debt, which is reflected in lower rates. The cooperative itself does not earn a "return" on member equity because the member-owners are the investors. As to the cooperative itself, member equity has a zero cost.

In contrast to the cooperative business model, shareholders own the investor-owned electric utilities. Vertically integrated electric utilities provide distribution, transmission and generation service. Shareholders do not provide capital at zero cost. Shareholders require a reasonable rate of return. Shareholders do not earn a return through avoided interest expense and lower rates. Instead, they earn a return through growth in the value of the utilities, usually in the form of gains in the stock price and in dividends. Stock gains and dividends are both subject to federal and state income and capital gains taxes, whereas cooperatives are not subject to these taxes.

It is instructive to put the shoe on the other foot. This Commission sets the ROE for investor owned electric utilities through discounted cash flow, capital asset pricing model, risk premium and other accepted approaches. This Commission has never attempted to set the investor owned utility ROE based on comparisons to G&T TIER.

Q. What is your recommendation for the TIER in this proceeding?

A. I recommend a TIER of 1.30X in the base revenue requirement and in the ES. This TIER will ensure that the Company maintains its investment grade credit ratings. This TIER will ensure that the Company has sufficient liquidity and access to capital at a reasonable cost. It also will ensure that the members' equity will continue to grow, but at a more reasonable pace, not the accelerated pace that would result with a TIER of 1.50X as the Company proposes.

Q. What are the effects of your recommendation?

A. The effects are an incremental reduction of $11.565 million in the base revenue requirement and an incremental reduction of $5.957 million in the ES revenue requirement.

Q. Does this complete your testimony?

A. Yes.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE ELECTRONIC APPLICATION OF EAST	**)**	
KENTUCKY POWER COOPERATIVE, INC.	**)**	
FOR A GENERAL ADJUSTMENT OF RATES,	**)**	**CASE NO. 2021-00103**
APPROVAL OF DEPRECIATION STUDY,	**)**	
AMORTIZATION OF CERTAIN REGULATORY	**)**	
ASSETS, AND OTHER GENERAL RELIEF	**)**	

EXHIBITS

OF

LANE KOLLEN

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY

AND NUCOR STEEL GALLATIN

J. KENNEDY AND ASSOCIATES, INC.
ROSWELL, GEORGIA

JUNE 2021

EXHIBIT___(LK-1)

RESUME OF LANE KOLLEN, VICE PRESIDENT

EDUCATION

University of Toledo, BBA
Accounting

University of Toledo, MBA

Luther Rice University, MA

PROFESSIONAL CERTIFICATIONS

Certified Public Accountant (CPA)

Certified Management Accountant (CMA)

PROFESSIONAL AFFILIATIONS

American Institute of Certified Public Accountants

Georgia Society of Certified Public Accountants

Institute of Management Accountants

Society of Depreciation Professionals

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

RESUME OF LANE KOLLEN, VICE PRESIDENT

EXPERIENCE

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

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

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

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

CLIENTS SERVED

Industrial Companies and Groups

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

Regulatory Commissions and Government Agencies

Cities in Texas-New Mexico Power Company's Service Territory
Cities in AEP Texas Central Company's Service Territory
Cities in AEP Texas North Company's Service Territory
City of Austin
Georgia Public Service Commission Staff
Florida Office of Public Counsel
Indiana Office of Utility Consumer Counsel
Kentucky Office of Attorney General
Louisiana Public Service Commission
Louisiana Public Service Commission Staff
Maine Office of Public Advocate
New York City
New York State Energy Office
South Carolina Office of Regulatory Staff
Texas Office of Public Utility Counsel
Utah Office of Consumer Services

Utilities

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

**Expert Testimony Appearances
of
Lane Kollen
As of June 2021**

Date	Case	Jurisdict.	Party	Utility	Subject
10/86	U-17282 Interim	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
11/86	U-17282 Interim Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements financial solvency.
12/86	9613	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Revenue requirements accounting adjustments financial workout plan.
1/87	U-17282 Interim	LA 19th Judicial District Ct.	Louisiana Public Service Commission Staff	Gulf States Utilities	Cash revenue requirements, financial solvency.
3/87	General Order 236	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Tax Reform Act of 1986.
4/87	U-17282 Prudence	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
4/87	M-100 Sub 113	NC	North Carolina Industrial Energy Consumers	Duke Power Co.	Tax Reform Act of 1986.
5/87	86-524-E-SC	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
5/87	U-17282 Case In Chief	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Case In Chief Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, financial solvency.
7/87	U-17282 Prudence Surrebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Prudence of River Bend 1, economic analyses, cancellation studies.
7/87	86-524 E-SC Rebuttal	WV	West Virginia Energy Users' Group	Monongahela Power Co.	Revenue requirements, Tax Reform Act of 1986.
8/87	9885	KY	Attorney General Div. of Consumer Protection	Big Rivers Electric Corp.	Financial workout plan.
8/87	E-015/GR-87-223	MN	Taconite Intervenors	Minnesota Power & Light Co.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
10/87	870220-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, Tax Reform Act of 1986.
11/87	87-07-01	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Tax Reform Act of 1986.
1/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Revenue requirements, River Bend 1 phase-in plan, rate of return.
2/88	9934	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Economics of Trimble County, completion.
2/88	10064	KY	Kentucky Industrial Utility	Louisville Gas &	Revenue requirements, O&M expense, capital

Expert Testimony Appearances
of
Lane Kollen
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
			Customers	Electric Co.	structure, excess deferred income taxes.
5/88	10217	KY	Alcan Aluminum National Southwire	Big Rivers Electric Corp.	Financial workout plan.
5/88	M-87017-1C001	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery.
5/88	M-87017-2C005	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery.
6/88	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Prudence of River Bend 1 economic analyses, cancellation studies, financial modeling.
7/88	M-87017-1C001 Rebuttal	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
7/88	M-87017-2C005 Rebuttal	PA	GPU Industrial Intervenors	Pennsylvania Electric Co.	Nonutility generator deferred cost recovery, SFAS No. 92.
9/88	88-05-25	CT	Connecticut Industrial Energy Consumers	Connecticut Light & Power Co.	Excess deferred taxes, O&M expenses.
9/88	10064 Rehearing	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Premature retirements, interest expense.
10/88	88-170-EL-AIR	OH	Ohio Industrial Energy Consumers	Cleveland Electric Illuminating Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	88-171-EL-AIR	OH	Ohio Industrial Energy Consumers	Toledo Edison Co.	Revenue requirements, phase-in, excess deferred taxes, O&M expenses, financial considerations, working capital.
10/88	8800-355-EI	FL	Florida Industrial Power Users' Group	Florida Power & Light Co.	Tax Reform Act of 1986, tax expenses, O&M expenses, pension expense (SFAS No. 87).
10/88	3780-U	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Co.	Pension expense (SFAS No. 87).
11/88	U-17282 Remand	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Rate base exclusion plan (SFAS No. 71).
12/88	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87).
12/88	U-17949 Rebuttal	LA	Louisiana Public Service Commission Staff	South Central Bell	Compensated absences (SFAS No. 43), pension expense (SFAS No. 87), Part 32, income tax normalization.
2/89	U-17282 Phase II	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, phase-in of River Bend 1, recovery of canceled plant.
6/89	881602-EU 890326-EU	FL	Talquin Electric Cooperative	Talquin/City of Tallahassee	Economic analyses, incremental cost-of-service, average customer rates.

Expert Testimony Appearances
of
Lane Kollen
As of June 2021

Date	Case	Jurisdict.	Party	Utility	Subject
7/89	U-17970	LA	Louisiana Public Service Commission Staff	AT&T Communications of South Central States	Pension expense (SFAS No. 87), compensated absences (SFAS No. 43), Part 32.
8/89	8555	TX	Occidental Chemical Corp.	Houston Lighting & Power Co.	Cancellation cost recovery, tax expense, revenue requirements.
8/89	3840-U	GA	Georgia Public Service Commission Staff	Georgia Power Co.	Promotional practices, advertising, economic development.
9/89	U-17282 Phase II Detailed	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
10/89	8880	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Deferred accounting treatment, sale/leaseback.
10/89	8928	TX	Enron Gas Pipeline	Texas-New Mexico Power Co.	Revenue requirements, imputed capital structure, cash working capital.
10/89	R-891364	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements.
11/89 12/89	R-891364 Surrebuttal (2 Filings)	PA	Philadelphia Area Industrial Energy Users Group	Philadelphia Electric Co.	Revenue requirements, sale/leaseback.
1/90	U-17282 Phase II Detailed Rebuttal	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements, detailed investigation.
1/90	U-17282 Phase III	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Phase-in of River Bend 1, deregulated asset plan.
3/90	890319-EI	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	890319-EI Rebuttal	FL	Florida Industrial Power Users Group	Florida Power & Light Co.	O&M expenses, Tax Reform Act of 1986.
4/90	U-17282	LA 19th Judicial District Ct.	Louisiana Public Service Commission	Gulf States Utilities	Fuel clause, gain on sale of utility assets.
9/90	90-158	KY	Kentucky Industrial Utility Customers	Louisville Gas & Electric Co.	Revenue requirements, post-test year additions, forecasted test year.
12/90	U-17282 Phase IV	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Revenue requirements.
3/91	29327, et. al.	NY	Multiple Intervenors	Niagara Mohawk Power Corp.	Incentive regulation.
5/91	9945	TX	Office of Public Utility Counsel of Texas	El Paso Electric Co.	Financial modeling, economic analyses, prudence of Palo Verde 3.

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Date	Case	Jurisdict.	Party	Utility	Subject
9/91	P-910511 P-910512	PA	Allegheny Ludlum Corp., Armco Advanced Materials Co., The West Penn Power Industrial Users' Group	West Penn Power Co.	Recovery of CAAA costs, least cost financing.
9/91	91-231-E-NC	WV	West Virginia Energy Users Group	Monongahela Power Co.	Recovery of CAAA costs, least cost financing.
11/91	U-17282	LA	Louisiana Public Service Commission Staff	Gulf States Utilities	Asset impairment, deregulated asset plan, revenue requirements.
12/91	91-410-EL-AIR	OH	Air Products and Chemicals, Inc., Armco Steel Co., General Electric Co., Industrial Energy Consumers	Cincinnati Gas & Electric Co.	Revenue requirements, phase-in plan.
12/91	PUC Docket 10200	TX	Office of Public Utility Counsel of Texas	Texas-New Mexico Power Co.	Financial integrity, strategic planning, declined business affiliations.
5/92	910890-EI	FL	Occidental Chemical Corp.	Florida Power Corp.	Revenue requirements, O&M expense, pension expense, OPEB expense, fossil dismantling, nuclear decommissioning.
8/92	R-00922314	PA	GPU Industrial Intervenors	Metropolitan Edison Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
9/92	92-043	KY	Kentucky Industrial Utility Consumers	Generic Proceeding	OPEB expense.
9/92	920324-EI	FL	Florida Industrial Power Users' Group	Tampa Electric Co.	OPEB expense.
9/92	39348	IN	Indiana Industrial Group	Generic Proceeding	OPEB expense.
9/92	910840-PU	FL	Florida Industrial Power Users' Group	Generic Proceeding	OPEB expense.
9/92	39314	IN	Industrial Consumers for Fair Utility Rates	Indiana Michigan Power Co.	OPEB expense.
11/92	U-19904	LA	Louisiana Public Service Commission Staff	Gulf States Utilities /Entergy Corp.	Merger.
11/92	8469	MD	Westvaco Corp., Eastalco Aluminum Co.	Potomac Edison Co.	OPEB expense.
11/92	92-1715-AU-COI	OH	Ohio Manufacturers Association	Generic Proceeding	OPEB expense.
12/92	R-00922378	PA	Armco Advanced Materials Co., The WPP Industrial Intervenors	West Penn Power Co.	Incentive regulation, performance rewards, purchased power risk, OPEB expense.
12/92	U-19949	LA	Louisiana Public Service Commission Staff	South Central Bell	Affiliate transactions, cost allocations, merger.

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

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Date	Case	Jurisdict.	Party	Utility	Subject
9/94	U-17735	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policies, exclusion of River Bend, other revenue requirement issues.
10/94	3905-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Incentive rate plan, earnings review.
10/94	5258-U	GA	Georgia Public Service Commission Staff	Southern Bell Telephone Co.	Alternative regulation, cost allocation.
11/94	U-19904 Initial Post-Merger Earnings Review (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	River Bend phase-in plan, deregulated asset plan, capital structure, other revenue requirement issues.
11/94	U-17735 (Rebuttal)	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, exclusion of River Bend, other revenue requirement issues.
4/95	R-00943271	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Revenue requirements. Fossil dismantling, nuclear decommissioning.
6/95	3905-U Rebuttal	GA	Georgia Public Service Commission	Southern Bell Telephone Co.	Incentive regulation, affiliate transactions, revenue requirements, rate refund.
6/95	U-19904 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
10/95	95-02614	TN	Tennessee Office of the Attorney General Consumer Advocate	BellSouth Telecommunications, Inc.	Affiliate transactions.
10/95	U-21485 (Direct)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
11/95	U-19904 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co. Division	Gas, coal, nuclear fuel costs, contract prudence, base/fuel realignment.
11/95 12/95	U-21485 (Supplemental Direct) U-21485 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Gulf States Utilities Co.	Nuclear O&M, River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues.
1/96	95-299-EL-AIR 95-300-EL-AIR	OH	Industrial Energy Consumers	The Toledo Edison Co., The Cleveland Electric Illuminating Co.	Competition, asset write-offs and revaluation, O&M expense, other revenue requirement issues.
2/96	PUC Docket 14965	TX	Office of Public Utility Counsel	Central Power & Light	Nuclear decommissioning.
5/96	95-485-LCS	NM	City of Las Cruces	El Paso Electric Co.	Stranded cost recovery, municipalization.
7/96	8725	MD	The Maryland Industrial Group and Redland Genstar, Inc.	Baltimore Gas & Electric Co., Potomac Electric Power Co., and Constellation Energy Corp.	Merger savings, tracking mechanism, earnings sharing plan, revenue requirement issues.

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9/96 11/96	U-22092 U-22092 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	River Bend phase-in plan, base/fuel realignment, NOL and AltMin asset deferred taxes, other revenue requirement issues, allocation of regulated/nonregulated costs.
10/96	96-327	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental surcharge recoverable costs.
2/97	R-00973877	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Stranded cost recovery, regulatory assets and liabilities, intangible transition charge, revenue requirements.
3/97	96-489	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental surcharge recoverable costs, system agreements, allowance inventory, jurisdictional allocation.
6/97	TO-97-397	MO	MCI Telecommunications Corp., Inc., MCImetro Access Transmission Services, Inc.	Southwestern Bell Telephone Co.	Price cap regulation, revenue requirements, rate of return.
6/97	R-00973953	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	R-00973954	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
7/97	U-22092	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Depreciation rates and methodologies, River Bend phase-in plan.
8/97	97-300	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co., Kentucky Utilities Co.	Merger policy, cost savings, surcredit sharing mechanism, revenue requirements, rate of return.
8/97	R-00973954 (Surrebuttal)	PA	PP&L Industrial Customer Alliance	Pennsylvania Power & Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
10/97	97-204	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness.
10/97	R-974008	PA	Metropolitan Edison Industrial Users Group	Metropolitan Edison Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
10/97	R-974009	PA	Penelec Industrial Customer Alliance	Pennsylvania Electric Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements.
11/97	97-204 (Rebuttal)	KY	Alcan Aluminum Corp. Southwire Co.	Big Rivers Electric Corp.	Restructuring, revenue requirements, reasonableness of rates, cost allocation.
11/97	U-22491	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.

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11/97	R-00973953 (Surrebuttal)	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning.
11/97	R-973981	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements, securitization.
11/97	R-974104	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
12/97	R-973981 (Surrebuttal)	PA	West Penn Power Industrial Intervenors	West Penn Power Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, fossil decommissioning, revenue requirements.
12/97	R-974104 (Surrebuttal)	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Restructuring, deregulation, stranded costs, regulatory assets, liabilities, nuclear and fossil decommissioning, revenue requirements, securitization.
1/98	U-22491 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
2/98	8774	MD	Westvaco	Potomac Edison Co.	Merger of Duquesne, AE, customer safeguards, savings sharing.
3/98	U-22092 (Allocated Stranded Cost Issues)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	8390-U	GA	Georgia Natural Gas Group, Georgia Textile Manufacturers Assoc.	Atlanta Gas Light Co.	Restructuring, unbundling, stranded costs, incentive regulation, revenue requirements.
3/98	U-22092 (Allocated Stranded Cost Issues) (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Restructuring, stranded costs, regulatory assets, securitization, regulatory mitigation.
3/98	U-22491 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, other revenue requirement issues.
10/98	97-596	ME	Maine Office of the Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
10/98	9355-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Co.	Affiliate transactions.
10/98	U-17735 Rebuttal	LA	Louisiana Public Service Commission Staff	Cajun Electric Power Cooperative	G&T cooperative ratemaking policy, other revenue requirement issues.

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Date	Case	Jurisdict.	Party	Utility	Subject
11/98	U-23327	LA	Louisiana Public Service Commission Staff	SWEPCO, CSW and AEP	Merger policy, savings sharing mechanism, affiliate transaction conditions.
12/98	U-23358 (Direct)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
12/98	98-577	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
1/99	98-10-07	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, investment tax credits, accumulated deferred income taxes, excess deferred income taxes.
3/99	U-23358 (Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
3/99	98-474	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements, alternative forms of regulation.
3/99	98-426	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, alternative forms of regulation.
3/99	99-082	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
3/99	99-083	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
4/99	U-23358 (Supplemental Surrebuttal)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
4/99	99-03-04	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
4/99	99-02-05	CT	Connecticut Industrial Utility Customers	Connecticut Light and Power Co.	Regulatory assets and liabilities, stranded costs, recovery mechanisms.
5/99	98-426 99-082 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
5/99	98-474 99-083 (Additional Direct)	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
5/99	98-426 98-474 (Response to Amended Applications)	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Co.	Alternative regulation.
6/99	97-596	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Request for accounting order regarding electric industry restructuring costs.
7/99	U-23358	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate transactions, cost allocations.

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Date	Case	Jurisdict.	Party	Utility	Subject
7/99	99-03-35	CT	Connecticut Industrial Energy Consumers	United Illuminating Co.	Stranded costs, regulatory assets, tax effects of asset divestiture.
7/99	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co., Central and South West Corp, American Electric Power Co.	Merger Settlement and Stipulation.
7/99	97-596 Surrebuttal	ME	Maine Office of Public Advocate	Bangor Hydro-Electric Co.	Restructuring, unbundling, stranded cost, T&D revenue requirements.
7/99	98-0452-E-GI	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
8/99	98-577 Surrebuttal	ME	Maine Office of Public Advocate	Maine Public Service Co.	Restructuring, unbundling, stranded costs, T&D revenue requirements.
8/99	98-426 99-082 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co.	Revenue requirements.
8/99	98-474 98-083 Rebuttal	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements.
8/99	98-0452-E-GI Rebuttal	WV	West Virginia Energy Users Group	Monongahela Power, Potomac Edison, Appalachian Power, Wheeling Power	Regulatory assets and liabilities.
10/99	U-24182 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
11/99	PUC Docket 21527	TX	The Dallas-Fort Worth Hospital Council and Coalition of Independent Colleges and Universities	TXU Electric	Restructuring, stranded costs, taxes, securitization.
11/99	U-23358 Surrebuttal Affiliate Transactions Review	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Service company affiliate transaction costs.
01/00	U-24182 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, affiliate transactions, tax issues, and other revenue requirement issues.
04/00	99-1212-EL-ETP 99-1213-EL-ATA 99-1214-EL-AAM	OH	Greater Cleveland Growth Association	First Energy (Cleveland Electric Illuminating, Toledo Edison)	Historical review, stranded costs, regulatory assets, liabilities.

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Date	Case	Jurisdict.	Party	Utility	Subject
05/00	2000-107	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	ECR surcharge roll-in to base rates.
05/00	U-24182 Supplemental Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Affiliate expense proforma adjustments.
05/00	A-110550F0147	PA	Philadelphia Area Industrial Energy Users Group	PECO Energy	Merger between PECO and Unicom.
05/00	99-1658-EL-ETP	OH	AK Steel Corp.	Cincinnati Gas & Electric Co.	Regulatory transition costs, including regulatory assets and liabilities, SFAS 109, ADIT, EDIT, ITC.
07/00	PUC Docket 22344	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	Statewide Generic Proceeding	Escalation of O&M expenses for unbundled T&D revenue requirements in projected test year.
07/00	U-21453	LA	Louisiana Public Service Commission	SWEPCO	Stranded costs, regulatory assets and liabilities.
08/00	U-24064	LA	Louisiana Public Service Commission Staff	CLECO	Affiliate transaction pricing ratemaking principles, subsidization of nonregulated affiliates, ratemaking adjustments.
10/00	SOAH Docket 473-00-1015 PUC Docket 22350	TX	The Dallas-Fort Worth Hospital Council and The Coalition of Independent Colleges and Universities	TXU Electric Co.	Restructuring, T&D revenue requirements, mitigation, regulatory assets and liabilities.
10/00	R-00974104 Affidavit	PA	Duquesne Industrial Intervenors	Duquesne Light Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, capital costs, switchback costs, and excess pension funding.
11/00	P-00001837 R-00974008 P-00001838 R-00974009	PA	Metropolitan Edison Industrial Users Group Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Final accounting for stranded costs, including treatment of auction proceeds, taxes, regulatory assets and liabilities, transaction costs.
12/00	U-21453, U-20925, U-22092 (Subdocket C) Surrebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Stranded costs, regulatory assets.
01/01	U-24993 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Allocation of regulated and nonregulated costs, tax issues, and other revenue requirement issues.
01/01	U-21453, U-20925, U-22092 (Subdocket B) Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Industry restructuring, business separation plan, organization structure, hold harmless conditions, financing.
01/01	Case No. 2000-386	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Recovery of environmental costs, surcharge mechanism.

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Date	Case	Jurisdict.	Party	Utility	Subject
01/01	Case No. 2000-439	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Recovery of environmental costs, surcharge mechanism.
02/01	A-110300F0095 A-110400F0040	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	GPU, Inc. FirstEnergy Corp.	Merger, savings, reliability.
03/01	P-00001860 P-00001861	PA	Met-Ed Industrial Users Group, Penelec Industrial Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of costs due to provider of last resort obligation.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Settlement Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on overall plan structure.
04/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
05/01	U-21453, U-20925, U-22092 (Subdocket B) Contested Issues Transmission and Distribution Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: agreements, hold harmless conditions, separations methodology.
07/01	U-21453, U-20925, U-22092 (Subdocket B) Transmission and Distribution Term Sheet	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Business separation plan: settlement agreement on T&D issues, agreements necessary to implement T&D separations, hold harmless conditions, separations methodology.
10/01	14000-U	GA	Georgia Public Service Commission Adversary Staff	Georgia Power Company	Revenue requirements, Rate Plan, fuel clause recovery.
11/01	14311-U Direct Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
11/01	U-25687 Direct	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, capital structure, allocation of regulated and nonregulated costs, River Bend uprate.
02/02	PUC Docket 25230	TX	The Dallas-Fort Worth Hospital Council and the Coalition of Independent Colleges and Universities	TXU Electric	Stipulation. Regulatory assets, securitization financing.

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02/02	U-25687 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
03/02	14311-U Rebuttal Panel with Bolin Killings	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, earnings sharing plan, service quality standards.
03/02	14311-U Rebuttal Panel with Michelle L. Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements, revenue forecast, O&M expense, depreciation, plant additions, cash working capital.
03/02	001148-EI	FL	South Florida Hospital and Healthcare Assoc.	Florida Power & Light Co.	Revenue requirements. Nuclear life extension, storm damage accruals and reserve, capital structure, O&M expense.
04/02	U-25687 (Suppl. Surrebuttal)	LA	Louisiana Public Service Commission	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, River Bend uprate.
04/02	U-21453, U-20925 U-22092 (Subdocket C)	LA	Louisiana Public Service Commission	SWEPCO	Business separation plan, T&D Term Sheet, separations methodologies, hold harmless conditions.
08/02	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.
08/02	U-25888	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc. and Entergy Louisiana, Inc.	System Agreement, production cost disparities, prudence.
09/02	2002-00224 2002-00225	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Line losses and fuel clause recovery associated with off-system sales.
11/02	2002-00146 2002-00147	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Environmental compliance costs and surcharge recovery.
01/03	2002-00169	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Power Co.	Environmental compliance costs and surcharge recovery.
04/03	2002-00429 2002-00430	KY	Kentucky Industrial Utilities Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Extension of merger surcredit, flaws in Companies' studies.
04/03	U-26527	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
06/03	EL01-88-000 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	System Agreement, production cost equalization, tariffs.

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06/03	2003-00068	KY	Kentucky Industrial Utility Customers	Kentucky Utilities Co.	Environmental cost recovery, correction of base rate error.
11/03	ER03-753-000	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Unit power purchases and sale cost-based tariff pursuant to System Agreement.
11/03	ER03-583-000, ER03-583-001, ER03-583-002 ER03-681-000, ER03-681-001 ER03-682-000, ER03-682-001, ER03-682-002 ER03-744-000, ER03-744-001 (Consolidated)	FERC	Louisiana Public Service Commission	Entergy Services, Inc., the Entergy Operating Companies, EWO Marketing, L.P, and Entergy Power, Inc.	Unit power purchases and sale agreements, contractual provisions, projected costs, levelized rates, and formula rates.
12/03	U-26527 Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
12/03	2003-0334 2003-0335	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Earnings Sharing Mechanism.
12/03	U-27136	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	Purchased power contracts between affiliates, terms and conditions.
03/04	U-26527 Supplemental Surrebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Revenue requirements, corporate franchise tax, conversion to LLC, capital structure, post-test year adjustments.
03/04	2003-00433	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas & Electric Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	2003-00434	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co.	Revenue requirements, depreciation rates, O&M expense, deferrals and amortization, earnings sharing mechanism, merger surcredit, VDT surcredit.
03/04	SOAH Docket 473-04-2459 PUC Docket 29206	TX	Cities Served by Texas-New Mexico Power Co.	Texas-New Mexico Power Co.	Stranded costs true-up, including valuation issues, ITC, ADIT, excess earnings.
05/04	04-169-EL-UNC	OH	Ohio Energy Group, Inc.	Columbus Southern Power Co. & Ohio Power Co.	Rate stabilization plan, deferrals, T&D rate increases, earnings.
06/04	SOAH Docket 473-04-4555 PUC Docket 29526	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Stranded costs true-up, including valuation issues, ITC, EDIT, excess mitigation credits, capacity auction true-up revenues, interest.

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08/04	SOAH Docket 473-04-4555 PUC Docket 29526 (Suppl Direct)	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric	Interest on stranded cost pursuant to Texas Supreme Court remand.
09/04	U-23327 Subdocket B	LA	Louisiana Public Service Commission Staff	SWEPCO	Fuel and purchased power expenses recoverable through fuel adjustment clause, trading activities, compliance with terms of various LPSC Orders.
10/04	U-23327 Subdocket A	LA	Louisiana Public Service Commission Staff	SWEPCO	Revenue requirements.
12/04	Case Nos. 2004-00321, 2004-00372	KY	Gallatin Steel Co.	East Kentucky Power Cooperative, Inc., Big Sandy Recc, et al.	Environmental cost recovery, qualified costs, TIER requirements, cost allocation.
01/05	30485	TX	Houston Council for Health and Education	CenterPoint Energy Houston Electric, LLC	Stranded cost true-up including regulatory Central Co. assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
02/05	18638-U	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Revenue requirements.
02/05	18638-U Panel with Tony Wackerly	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Comprehensive rate plan, pipeline replacement program surcharge, performance based rate plan.
02/05	18638-U Panel with Michelle Thebert	GA	Georgia Public Service Commission Adversary Staff	Atlanta Gas Light Co.	Energy conservation, economic development, and tariff issues.
03/05	Case Nos. 2004-00426, 2004-00421	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, excess common equity ratio, deferral and amortization of nonrecurring O&M expense.
06/05	2005-00068	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	Environmental cost recovery, Jobs Creation Act of 2004 and §199 deduction, margins on allowances used for AEP system sales.
06/05	050045-EI	FL	South Florida Hospital and Heallthcare Assoc.	Florida Power & Light Co.	Storm damage expense and reserve, RTO costs, O&M expense projections, return on equity performance incentive, capital structure, selective second phase post-test year rate increase.
08/05	31056	TX	Alliance for Valley Healthcare	AEP Texas Central Co.	Stranded cost true-up including regulatory assets and liabilities, ITC, EDIT, capacity auction, proceeds, excess mitigation credits, retrospective and prospective ADIT.
09/05	20298-U	GA	Georgia Public Service Commission Adversary Staff	Atmos Energy Corp.	Revenue requirements, roll-in of surcharges, cost recovery through surcharge, reporting requirements.
09/05	20298-U	GA	Georgia Public Service	Atmos Energy Corp.	Affiliate transactions, cost allocations, capitalization,

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	Panel with Victoria Taylor		Commission Adversary Staff		cost of debt.
10/05	04-42	DE	Delaware Public Service Commission Staff	Artesian Water Co.	Allocation of tax net operating losses between regulated and unregulated.
11/05	2005-00351 2005-00352	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric	Workforce Separation Program cost recovery and shared savings through VDT surcredit.
01/06	2005-00341	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Co.	System Sales Clause Rider, Environmental Cost Recovery Rider. Net Congestion Rider, Storm damage, vegetation management program, depreciation, off-system sales, maintenance normalization, pension and OPEB.
03/06	PUC Docket 31994	TX	Cities	Texas-New Mexico Power Co.	Stranded cost recovery through competition transition or change.
05/06	31994 Supplemental	TX	Cities	Texas-New Mexico Power Co.	Retrospective ADFIT, prospective ADFIT.
03/06	U-21453, U-20925, U-22092 (Subdocket B)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
03/06	NOPR Reg 104385-OR	IRS	Alliance for Valley Health Care and Houston Council for Health Education	AEP Texas Central Company and CenterPoint Energy Houston Electric	Proposed Regulations affecting flow- through to ratepayers of excess deferred income taxes and investment tax credits on generation plant that is sold or deregulated.
04/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, Inc.	2002-2004 Audit of Fuel Adjustment Clause Filings. Affiliate transactions.
07/06	R-00061366, Et. al.	PA	Met-Ed Ind. Users Group Pennsylvania Ind. Customer Alliance	Metropolitan Edison Co., Pennsylvania Electric Co.	Recovery of NUG-related stranded costs, government mandated program costs, storm damage costs.
07/06	U-23327	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
08/06	U-21453, U-20925, U-22092 (Subdocket J)	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc.	Jurisdictional separation plan.
11/06	05CVH03-3375 Franklin County Court Affidavit	OH	Various Taxing Authorities (Non-Utility Proceeding)	State of Ohio Department of Revenue	Accounting for nuclear fuel assemblies as manufactured equipment and capitalized plant.
12/06	U-23327 Subdocket A Reply Testimony	LA	Louisiana Public Service Commission Staff	Southwestern Electric Power Co.	Revenue requirements, formula rate plan, banking proposal.
03/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.

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03/07	PUC Docket 33309	TX	Cities	AEP Texas Central Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	PUC Docket 33310	TX	Cities	AEP Texas North Co.	Revenue requirements, including functionalization of transmission and distribution costs.
03/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Interim rate increase, RUS loan covenants, credit facility requirements, financial condition.
03/07	U-29157	LA	Louisiana Public Service Commission Staff	Cleco Power, LLC	Permanent (Phase II) storm damage cost recovery.
04/07	U-29764 Supplemental and Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States, Inc., Entergy Louisiana, LLC	Jurisdictional allocation of Entergy System Agreement equalization remedy receipts.
04/07	ER07-682-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and state income tax effects on equalization remedy receipts.
04/07	ER07-684-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Fuel hedging costs and compliance with FERC USOA.
05/07	ER07-682-000 Supplemental Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Allocation of intangible and general plant and A&G expenses to production and account 924 effects on MSS-3 equalization remedy payments and receipts.
06/07	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC, Entergy Gulf States, Inc.	Show cause for violating LPSC Order on fuel hedging costs.
07/07	2006-00472	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative	Revenue requirements, post-test year adjustments, TIER, surcharge revenues and costs, financial need.
07/07	ER07-956-000 Affidavit	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Storm damage costs related to Hurricanes Katrina and Rita and effects of MSS-3 equalization payments and receipts.
10/07	05-UR-103 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	05-UR-103 Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company, Wisconsin Gas, LLC	Revenue requirements, carrying charges on CWIP, amortization and return on regulatory assets, working capital, incentive compensation, use of rate base in lieu of capitalization, quantification and use of Point Beach sale proceeds.
10/07	25060-U Direct	GA	Georgia Public Service Commission Public Interest Adversary Staff	Georgia Power Company	Affiliate costs, incentive compensation, consolidated income taxes, §199 deduction.

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11/07	06-0033-E-CN Direct	WV	West Virginia Energy Users Group	Appalachian Power Company	IGCC surcharge during construction period and post-in-service date.
11/07	ER07-682-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	ER07-682-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization and allocation of intangible and general plant and A&G expenses.
01/08	07-551-EL-AIR Direct	OH	Ohio Energy Group, Inc.	Ohio Edison Company, Cleveland Electric Illuminating Company, Toledo Edison Company	Revenue requirements.
02/08	ER07-956-000 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
03/08	ER07-956-000 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and the Entergy Operating Companies	Functionalization of expenses, storm damage expense and reserves, tax NOL carrybacks in accounts, ADIT, nuclear service lives and effects on depreciation and decommissioning.
04/08	2007-00562, 2007-00563	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas and Electric Co.	Merger surcredit.
04/08	26837 Direct Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
05/08	26837 Suppl Rebuttal Bond, Johnson, Thebert, Kollen Panel	GA	Georgia Public Service Commission Staff	SCANA Energy Marketing, Inc.	Rule Nisi complaint.
06/08	2008-00115	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Environmental surcharge recoveries, including costs recovered in existing rates, TIER.

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07/08	27163 Direct	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Revenue requirements, including projected test year rate base and expenses.
07/08	27163 Taylor, Kollen Panel	GA	Georgia Public Service Commission Public Interest Advocacy Staff	Atmos Energy Corp.	Affiliate transactions and division cost allocations, capital structure, cost of debt.
08/08	6680-CE-170 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Nelson Dewey 3 or Colombia 3 fixed financial parameters.
08/08	6680-UR-116 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	CWIP in rate base, labor expenses, pension expense, financing, capital structure, decoupling.
08/08	6680-UR-116 Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Capital structure.
08/08	6690-UR-119 Direct	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, incentive compensation, Crane Creek Wind Farm incremental revenue requirement, capital structure.
09/08	6690-UR-119 Surrebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Public Service Corp.	Prudence of Weston 3 outage, Section 199 deduction.
09/08	08-935-EL-SSO, 08-918-EL-SSO	OH	Ohio Energy Group, Inc.	First Energy	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	08-917-EL-SSO	OH	Ohio Energy Group, Inc.	AEP	Standard service offer rates pursuant to electric security plan, significantly excessive earnings test.
10/08	2007-00564, 2007-00565, 2008-00251 2008-00252	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Co., Kentucky Utilities Company	Revenue forecast, affiliate costs, ELG v ASL depreciation procedures, depreciation expenses, federal and state income tax expense, capitalization, cost of debt.
11/08	EL08-51	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities, regulatory asset and bandwidth remedy.
11/08	35717	TX	Cities Served by Oncor Delivery Company	Oncor Delivery Company	Recovery of old meter costs, asset ADFIT, cash working capital, recovery of prior year restructuring costs, levelized recovery of storm damage costs, prospective storm damage accrual, consolidated tax savings adjustment.
12/08	27800	GA	Georgia Public Service Commission	Georgia Power Company	AFUDC versus CWIP in rate base, mirror CWIP, certification cost, use of short term debt and trust preferred financing, CWIP recovery, regulatory incentive.
01/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
01/09	ER08-1056 Supplemental Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Blytheville leased turbines; accumulated depreciation.

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02/09	EL08-51 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Spindletop gas storage facilities regulatory asset and bandwidth remedy.
02/09	2008-00409 Direct	KY	Kentucky Industrial Utility Customers, Inc.	East Kentucky Power Cooperative, Inc.	Revenue requirements.
03/09	ER08-1056 Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
03/09 04/09	U-21453, U-20925 U-22092 (Sub J) Direct Rebuttal	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
04/09	2009-00040 Direct-Interim (Oral)	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Emergency interim rate increase; cash requirements.
04/09	PUC Docket 36530	TX	State Office of Administrative Hearings	Oncor Electric Delivery Company, LLC	Rate case expenses.
05/09	ER08-1056 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy System Agreement bandwidth remedy calculations, including depreciation expense, ADIT, capital structure.
06/09	2009-00040 Direct-Permanent	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements, TIER, cash flow.
07/09	080677-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Multiple test years, GBRA rider, forecast assumptions, revenue requirement, O&M expense, depreciation expense, Economic Stimulus Bill, capital structure.
08/09	U-21453, U-20925, U-22092 (Subdocket J) Supplemental Rebuttal	LA	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC	Violation of EGSI separation order, ETI and EGSL separation accounting, Spindletop regulatory asset.
08/09	8516 and 29950	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Modification of PRP surcharge to include infrastructure costs.
09/09	05-UR-104 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Electric Power Company	Revenue requirements, incentive compensation, depreciation, deferral mitigation, capital structure, cost of debt.
09/09	09AL-299E Answer	CO	CF&I Steel, Rocky Mountain Steel Mills LP, Climax Molybdenum Company	Public Service Company of Colorado	Forecasted test year, historic test year, proforma adjustments for major plant additions, tax depreciation.

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09/09	6680-UR-117 Direct and Surrebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Power and Light Company	Revenue requirements, CWIP in rate base, deferral mitigation, payroll, capacity shutdowns, regulatory assets, rate of return.
10/09	09A-415E Answer	CO	Cripple Creek & Victor Gold Mining Company, et al.	Black Hills/CO Electric Utility Company	Cost prudence, cost sharing mechanism.
10/09	EL09-50 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
10/09	2009-00329	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Trimble County 2 depreciation rates.
12/09	PUE-2009-00030	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Return on equity incentive.
12/09	ER09-1224 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	ER09-1224 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
01/10	EL09-50 Rebuttal Supplemental Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback accumulated deferred income taxes, Entergy System Agreement bandwidth remedy calculations.
02/10	ER09-1224 Final	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Hypothetical versus actual costs, out of period costs, Spindletop deferred capital costs, Waterford 3 sale/leaseback ADIT.
02/10	30442 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Revenue requirement issues.
02/10	30442 McBride-Kollen Panel	GA	Georgia Public Service Commission Staff	Atmos Energy Corporation	Affiliate/division transactions, cost allocation, capital structure.
02/10	2009-00353	KY	Kentucky Industrial Utility Customers, Inc., Attorney General	Louisville Gas and Electric Company, Kentucky Utilities Company	Ratemaking recovery of wind power purchased power agreements.
03/10	2009-00545	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Ratemaking recovery of wind power purchased power agreement.
03/10	E015/GR-09-1151	MN	Large Power Interveners	Minnesota Power	Revenue requirement issues, cost overruns on environmental retrofit project.

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04/10	2009-00459	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Revenue requirement issues.
04/10	2009-00548, 2009-00549	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	Revenue requirement issues.
08/10	31647	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Revenue requirement and synergy savings issues.
08/10	31647 Wackerly-Kollen Panel	GA	Georgia Public Service Commission Staff	Atlanta Gas Light Company	Affiliate transaction and Customer First program issues.
08/10	2010-00204	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	PPL acquisition of E.ON U.S. (LG&E and KU) conditions, acquisition savings, sharing deferral mechanism.
09/10	38339 Direct and Cross-Rebuttal	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Revenue requirement issues, including consolidated tax savings adjustment, incentive compensation FIN 48; AMS surcharge including roll-in to base rates; rate case expenses.
09/10	EL10-55	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
09/10	2010-00167	KY	Gallatin Steel	East Kentucky Power Cooperative, Inc.	Revenue requirements.
09/10	U-23327 Subdocket E Direct	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
11/10	U-23327 Rebuttal	LA	Louisiana Public Service Commission	SWEPCO	Fuel audit: S02 allowance expense, variable O&M expense, off-system sales margin sharing.
09/10	U-31351	LA	Louisiana Public Service Commission Staff	SWEPCO and Valley Electric Membership Cooperative	Sale of Valley assets to SWEPCO and dissolution of Valley.
10/10	10-1261-EL-UNC	OH	Ohio OCC, Ohio Manufacturers Association, Ohio Energy Group, Ohio Hospital Association, Appalachian Peace and Justice Network	Columbus Southern Power Company	Significantly excessive earnings test.
10/10	10-0713-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, Potomac Edison Power Company	Merger of First Energy and Allegheny Energy.

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10/10	U-23327 Subdocket F Direct	LA	Louisiana Public Service Commission Staff	SWEPCO	AFUDC adjustments in Formula Rate Plan.
11/10	EL10-55 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Depreciation rates and expense input effects on System Agreement tariffs.
12/10	ER10-1350 Direct	FERC	Louisiana Public Service Commission	Entergy Services, Inc. Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
01/11	ER10-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Operating Cos	Waterford 3 lease amortization, ADIT, and fuel inventory effects on System Agreement tariffs.
03/11 04/11	ER10-2001 Direct Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc., Entergy Arkansas, Inc.	EAI depreciation rates.
04/11	U-23327 Subdocket E	LA	Louisiana Public Service Commission Staff	SWEPCO	Settlement, incl resolution of S02 allowance expense, var O&M expense, sharing of OSS margins.
04/11 05/11	38306 Direct Suppl Direct	TX	Cities Served by Texas-New Mexico Power Company	Texas-New Mexico Power Company	AMS deployment plan, AMS Surcharge, rate case expenses.
05/11	11-0274-E-GI	WV	West Virginia Energy Users Group	Appalachian Power Company, Wheeling Power Company	Deferral recovery phase-in, construction surcharge.
05/11	2011-00036	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Revenue requirements.
06/11	29849	GA	Georgia Public Service Commission Staff	Georgia Power Company	Accounting issues related to Vogtle risk-sharing mechanism.
07/11	ER11-2161 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
07/11	PUE-2011-00027	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Return on equity performance incentive.
07/11	11-346-EL-SSO 11-348-EL-SSO 11-349-EL-AAM 11-350-EL-AAM	OH	Ohio Energy Group	AEP-OH	Equity Stabilization Incentive Plan; actual earned returns; ADIT offsets in riders.
08/11	U-23327 Subdocket F Rebuttal	LA	Louisiana Public Service Commission Staff	SWEPCO	Depreciation rates and service lives; AFUDC adjustments.
08/11	05-UR-105	WI	Wisconsin Industrial Energy Group	WE Energies, Inc.	Suspended amortization expenses; revenue requirements.

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08/11	ER11-2161 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc. and Entergy Texas, Inc.	ETI depreciation rates; accounting issues.
09/11	PUC Docket 39504	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Investment tax credit, excess deferred income taxes; normalization.
09/11	2011-00161 2011-00162	KY	Kentucky Industrial Utility Consumers, Inc.	Louisville Gas & Electric Company, Kentucky Utilities Company	Environmental requirements and financing.
10/11	11-4571-EL-UNC 11-4572-EL-UNC	OH	Ohio Energy Group	Columbus Southern Power Company, Ohio Power Company	Significantly excessive earnings.
10/11	4220-UR-117 Direct	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	4220-UR-117 Surrebuttal	WI	Wisconsin Industrial Energy Group	Northern States Power-Wisconsin	Nuclear O&M, depreciation.
11/11	PUC Docket 39722	TX	Cities Served by AEP Texas Central Company	AEP Texas Central Company	Investment tax credit, excess deferred income taxes; normalization.
02/12	PUC Docket 40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Temporary rates.
03/12	11AL-947E Answer	CO	Climax Molybdenum Company and CF&I Steel, L.P. d/b/a Evraz Rocky Mountain Steel	Public Service Company of Colorado	Revenue requirements, including historic test year, future test year, CACJA CWIP, contra-AFUDC.
03/12	2011-00401	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Big Sandy 2 environmental retrofits and environmental surcharge recovery.
4/12	2011-00036 Direct Rehearing Supplemental Rebuttal Rehearing	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Rate case expenses, depreciation rates and expense.
04/12	10-2929-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, CRES capacity charges, Equity Stabilization Mechanism
05/12	11-346-EL-SSO 11-348-EL-SSO	OH	Ohio Energy Group	AEP Ohio Power	State compensation mechanism, Equity Stabilization Mechanism, Retail Stability Rider.
05/12	11-4393-EL-RDR	OH	Ohio Energy Group	Duke Energy Ohio, Inc.	Incentives for over-compliance on EE/PDR mandates.

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06/12	40020	TX	Cities Served by Oncor	Lone Star Transmission, LLC	Revenue requirements, including ADIT, bonus depreciation and NOL, working capital, self insurance, depreciation rates, federal income tax expense.
07/12	120015-EI	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Revenue requirements, including vegetation management, nuclear outage expense, cash working capital, CWIP in rate base.
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corp.	Environmental retrofits, including environmental surcharge recovery.
09/12	05-UR-106	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Electric Power Company	Section 1603 grants, new solar facility, payroll expenses, cost of debt.
10/12	2012-00221 2012-00222	KY	Kentucky Industrial Utility Customers, Inc.	Louisville Gas and Electric Company, Kentucky Utilities Company	Revenue requirements, including off-system sales, outage maintenance, storm damage, injuries and damages, depreciation rates and expense.
10/12	120015-EI Direct	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
11/12	120015-EI Rebuttal	FL	South Florida Hospital and Healthcare Association	Florida Power & Light Company	Settlement issues.
10/12	40604	TX	Steering Committee of Cities Served by Oncor	Cross Texas Transmission, LLC	Policy and procedural issues, revenue requirements, including AFUDC, ADIT – bonus depreciation & NOL, incentive compensation, staffing, self-insurance, net salvage, depreciation rates and expense, income tax expense.
11/12	40627 Direct	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
12/12	40443	TX	Cities Served by SWEPCO	Southwestern Electric Power Company	Revenue requirements, including depreciation rates and service lives, O&M expenses, consolidated tax savings, CWIP in rate base, Turk plant costs.
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Termination of purchased power contracts between EGSL and ETI, Spindletop regulatory asset.
01/13	ER12-1384 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	Little Gypsy 3 cancellation costs.
02/13	40627 Rebuttal	TX	City of Austin d/b/a Austin Energy	City of Austin d/b/a Austin Energy	Rate case expenses.
03/13	12-426-EL-SSO	OH	The Ohio Energy Group	The Dayton Power and Light Company	Capacity charges under state compensation mechanism, Service Stability Rider, Switching Tracker.

Expert Testimony Appearances
of
Lane Kollen
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Date	Case	Jurisdict.	Party	Utility	Subject
04/13	12-2400-EL-UNC	OH	The Ohio Energy Group	Duke Energy Ohio, Inc.	Capacity charges under state compensation mechanism, deferrals, rider to recover deferrals.
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Resource plan, including acquisition of interest in Mitchell plant.
05/13	2012-00535	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
06/13	12-3254-EL-UNC	OH	The Ohio Energy Group, Inc., Office of the Ohio Consumers' Counsel	Ohio Power Company	Energy auctions under CBP, including reserve prices.
07/13	2013-00144	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Biomass renewable energy purchase agreement.
07/13	2013-00221	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Hawesville Smelter market access.
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Revenue requirements, excess capacity, restructuring.
12/13	2013-00413	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Agreements to provide Century Sebree Smelter market access.
01/14	ER10-1350 Direct and Answering	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 lease accounting and treatment in annual bandwidth filings.
02/14	U-32981	LA	Louisiana Public Service Commission	Entergy Louisiana, LLC	Montauk renewable energy PPA.
04/14	ER13-432 Direct	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
05/14	PUE-2013-00132	VA	HP Hood LLC	Shenandoah Valley Electric Cooperative	Market based rate; load control tariffs.
07/14	PUE-2014-00033	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting, change in FAC Definitional Framework.
08/14	ER13-432 Rebuttal	FERC	Louisiana Public Service Commission	Entergy Gulf States Louisiana, LLC and Entergy Louisiana, LLC	UP Settlement benefits and damages.
08/14	2014-00134	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Requirements power sales agreements with Nebraska entities.
09/14	E-015/CN-12-1163 Direct	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class cost allocation.
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Allocation of fuel costs to off-system sales.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
10/14	ER13-1508	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Entergy service agreements and tariffs for affiliate power purchases and sales; return on equity.
10/14	14-0702-E-42T 14-0701-E-D	WV	West Virginia Energy Users Group	First Energy-Monongahela Power, Potomac Edison	Consolidated tax savings; payroll; pension, OPEB, amortization; depreciation; environmental surcharge.
11/14	E-015/CN-12-1163 Surrebuttal	MN	Large Power Intervenors	Minnesota Power	Great Northern Transmission Line; cost cap; AFUDC v. current recovery; rider v. base recovery; class allocation.
11/14	05-376-EL-UNC	OH	Ohio Energy Group	Ohio Power Company	Refund of IGCC CWIP financing cost recoveries.
11/14	14AL-0660E	CO	Climax, CF&I Steel	Public Service Company of Colorado	Historic test year v. future test year; AFUDC v. current return; CACJA rider, transmission rider; equivalent availability rider; ADIT; depreciation; royalty income; amortization.
12/14	EL14-026	SD	Black Hills Industrial Intervenors	Black Hills Power Company	Revenue requirement issues, including depreciation expense and affiliate charges.
12/14	14-1152-E-42T	WV	West Virginia Energy Users Group	AEP-Appalachian Power Company	Income taxes, payroll, pension, OPEB, deferred costs and write offs, depreciation rates, environmental projects surcharge.
01/15	9400-YO-100 Direct	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
01/15	14F-0336EG 14F-0404EG	CO	Development Recovery Company LLC	Public Service Company of Colorado	Line extension policies and refunds.
02/15	9400-YO-100 Rebuttal	WI	Wisconsin Industrial Energy Group	Wisconsin Energy Corporation	WEC acquisition of Integrys Energy Group, Inc.
03/15	2014-00396	KY	Kentucky Industrial Utility Customers, Inc.	AEP-Kentucky Power Company	Base, Big Sandy 2 retirement rider, environmental surcharge, and Big Sandy 1 operation rider revenue requirements, depreciation rates, financing, deferrals.
03/15	2014-00371 2014-00372	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Revenue requirements, staffing and payroll, depreciation rates.
04/15	2014-00450	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	AEP-Kentucky Power Company	Allocation of fuel costs between native load and off-system sales.
04/15	2014-00455	KY	Kentucky Industrial Utility Customers, Inc. and the Attorney General of the Commonwealth of Kentucky	Big Rivers Electric Corporation	Allocation of fuel costs between native load and off-system sales.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
04/15	ER2014-0370	MO	Midwest Energy Consumers' Group	Kansas City Power & Light Company	Affiliate transactions, operation and maintenance expense, management audit.
05/15	PUE-2015-00022	VA	Virginia Committee for Fair Utility Rates	Virginia Electric and Power Company	Fuel and purchased power hedge accounting; change in FAC Definitional Framework.
05/15 09/15	EL10-65 Direct, Rebuttal Complaint	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Accounting for AFUDC Debt, related ADIT.
07/15	EL10-65 Direct and Answering Consolidated Bandwidth Dockets	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Waterford 3 sale/leaseback ADIT, Bandwidth Formula.
09/15	14-1693-EL-RDR	OH	Public Utilities Commission of Ohio	Ohio Energy Group	PPA rider for charges or credits for physical hedges against market.
12/15	45188	TX	Cities Served by Oncor Electric Delivery Company	Oncor Electric Delivery Company	Hunt family acquisition of Oncor; transaction structure; income tax savings from real estate investment trust (REIT) structure; conditions.
12/15 01/16	6680-CE-176 Direct, Surrebuttal, Supplemental Rebuttal	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light Company	Need for capacity and economics of proposed Riverside Energy Center Expansion project; ratemaking conditions.
03/16 03/16 04/16 05/16 06/16	EL01-88 Remand Direct Answering Cross-Answering Rebuttal	FERC	Louisiana Public Service Commission	Entergy Services, Inc.	Bandwidth Formula: Capital structure, fuel inventory, Waterford 3 sale/leaseback, Vidalia purchased power, ADIT, Blythesville, Spindletop, River Bend AFUDC, property insurance reserve, nuclear depreciation expense.
03/16	15-1673-E-T	WV	West Virginia Energy Users Group	Appalachian Power Company	Terms and conditions of utility service for commercial and industrial customers, including security deposits.
04/16	39971 Panel Direct	GA	Georgia Public Service Commission Staff	Southern Company, AGL Resources, Georgia Power Company, Atlanta Gas Light Company	Southern Company acquisition of AGL Resources, risks, opportunities, quantification of savings, ratemaking implications, conditions, settlement.
04/16	2015-00343	KY	Office of the Attorney General	Atmos Energy Corporation	Revenue requirements, including NOL ADIT, affiliate transactions.
04/16	2016-00070	KY	Office of the Attorney General	Atmos Energy Corporation	R & D Rider.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
05/16	2016-00026 2016-00027	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Co., Louisville Gas & Electric Co.	Need for environmental projects, calculation of environmental surcharge rider.
05/16	16-G-0058 16-G-0059	NY	New York City	Keyspan Gas East Corp., Brooklyn Union Gas Company	Depreciation, including excess reserves, leak prone pipe.
06/16	160088-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Fuel Adjustment Clause Incentive Mechanism re: economy sales and purchases, asset optimization.
07/16	160021-EI	FL	South Florida Hospital and Healthcare Association	Florida Power and Light Company	Revenue requirements, including capital recovery, depreciation, ADIT.
07/16	16-057-01	UT	Office of Consumer Services	Dominion Resources, Inc. / Questar Corporation	Merger, risks, harms, benefits, accounting.
08/16	15-1022-EL-UNC 16-1105-EL-UNC	OH	Ohio Energy Group	AEP Ohio Power Company	SEET earnings, effects of other pending proceedings.
9/16	2016-00162	KY	Office of the Attorney General	Columbia Gas Kentucky	Revenue requirements, O&M expense, depreciation, affiliate transactions.
09/16	E-22 Sub 519, 532, 533	NC	Nucor Steel	Dominion North Carolina Power Company	Revenue requirements, deferrals and amortizations.
09/16	15-1256-G-390P (Reopened) 16-0922-G-390P	WV	West Virginia Energy Users Group	Mountaineer Gas Company	Infrastructure rider, including NOL ADIT and other income tax normalization and calculation issues.
10/16	10-2929-EL-UNC 11-346-EL-SSO 11-348-EL-SSO 11-349-EL-SSO 11-350-EL-SSO 14-1186-EL-RDR	OH	Ohio Energy Group	AEP Ohio Power Company	State compensation mechanism, capacity cost, Retail Stability Rider deferrals, refunds, SEET.
11/16	16-0395-EL-SSO Direct	OH	Ohio Energy Group	Dayton Power & Light Company	Credit support and other riders; financial stability of Utility, holding company.
12/16	Formal Case 1139	DC	Healthcare Council of the National Capital Area	Potomac Electric Power Company	Post test year adjust, merger costs, NOL ADIT, incentive compensation, rent.
01/17	46238	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company	Next Era acquisition of Oncor; goodwill, transaction costs, transition costs, cost deferrals, ratemaking issues.
02/17	16-0395-EL-SSO Direct (Stipulation)	OH	Ohio Energy Group	Dayton Power & Light Company	Non-unanimous stipulation re: credit support and other riders; financial stability of utility, holding company.
02/17	45414	TX	Cities of Midland, McAllen, and Colorado City	Sharyland Utilities, LP, Sharyland Distribution & Transmission Services, LLC	Income taxes, depreciation, deferred costs, affiliate expenses.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/17	2016-00370 2016-00371	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas and Electric Company	AMS, capital expenditures, maintenance expense, amortization expense, depreciation rates and expense.
06/17	29849 (Panel with Philip Hayet)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics.
08/17	17-0296-E-PC	WV	West Virginia Energy Users Group	Monongahela Power Company, The Potomac Edison Power Company	ADIT, OPEB.
10/17	2017-00179	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Weather normalization, Rockport lease, O&M, incentive compensation, depreciation, income taxes.
10/17	2017-00287	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers Electric Corporation	Fuel cost allocation to native load customers.
12/17	2017-00321	KY	Attorney General	Duke Energy Kentucky (Electric)	Revenues, depreciation, income taxes, O&M, regulatory assets, environmental surcharge rider, FERC transmission cost reconciliation rider.
12/17	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	Vogtle 3 and 4 economics, tax abandonment loss.
01/18	2017-00349	KY	Kentucky Attorney General	Atmos Energy Kentucky	O&M expense, depreciation, regulatory assets and amortization, Annual Review Mechanism, Pipeline Replacement Program and Rider, affiliate expenses.
06/18	18-0047	OH	Ohio Energy Group	Ohio Electric Utilities	Tax Cuts and Jobs Act. Reduction in income tax expense; amortization of excess ADIT.
07/18	T-34695	LA	LPSC Staff	Crimson Gulf, LLC	Revenues, depreciation, income taxes, O&M, ADIT.
08/18	48325	TX	Cities Served by Oncor	Oncor Electric Delivery Company	Tax Cuts and Jobs Act; amortization of excess ADIT.
08/18	48401	TX	Cities Served by TNMP	Texas-New Mexico Power Company	Revenues, payroll, income taxes, amortization of excess ADIT, capital structure.
08/18	2018-00146	KY	KIUC	Big Rivers Electric Corporation	Station Two contracts termination, regulatory asset, regulatory liability for savings
09/18 10/18	20170235-EI 20170236-EU Direct Supplemental Direct	FL	Office of Public Counsel	Florida Power & Light Company	FP&L acquisition of City of Vero Beach municipal electric utility systems.

**Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
09/18 10/18	2017-370-E Direct 2017-207, 305, 370-E Surrebuttal Supplemental Surrebuttal	SC	Office of Regulatory Staff	South Carolina Electric & Gas Company and Dominion Energy, Inc.	Recovery of Summer 2 and 3 new nuclear development costs, related regulatory liabilities, securitization, NOL carryforward and ADIT, TCJA savings, merger conditions and savings.
12/18	2018-00261	KY	Attorney General	Duke Energy Kentucky (Gas)	Revenues, O&M, regulatory assets, payroll, integrity management, incentive compensation, cash working capital.
01/19	2018-00294 2018-00295	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company, Louisville Gas & Electric Company	AFUDC v. CWIP in rate base, transmission and distribution plant additions, capitalization, revenues generation outage expense, depreciation rates and expenses, cost of debt.
01/19	2018-00281	KY	Attorney General	Atmos Energy Corp.	AFUDC v. CWIP in rate base, ALG v. ELG depreciation rates, cash working capital, PRP Rider, forecast plant additions, forecast expenses, cost of debt, corporate cost allocation.
02/19 04/19	UD-18-17 Direct Surrebuttal and Cross-Answering	New Orleans	Crescent City Power Users Group	Entergy New Orleans, LLC	Post-test year adjustments, storm reserve fund, NOL ADIT, FIN48 ADIT, cash working capital, depreciation, amortization, capital structure, formula rate plans, purchased power rider.
03/19	2018-0358	KY	Attorney General	Kentucky American Water Company	Capital expenditures, cash working capital, payroll expense, incentive compensation, chemicals expense, electricity expense, water losses, rate case expense, excess deferred income taxes.
03/19	48929	TX	Steering Committee of Cities Served by Oncor	Oncor Electric Delivery Company LLC, Sempra Energy, Sharyland Distribution & Transmission Services, L.L.C.., Sharyland Utilities, L.P.	Sale, transfer, merger transactions, hold harmless and other regulatory conditions.
06/19	49421	TX	Gulf Coast Coalition of Cities	CenterPoint Energy Houston Electric	Prepaid pension asset, accrued OPEB liability, regulatory assets and liabilities, merger savings, storm damage expense, excess deferred income taxes.
07/19	49494	TX	Cities Served by AEP Texas	AEP Texas, Inc.	Plant in service, prepaid pension asset, O&M, ROW costs, incentive compensation, self-insurance expense, excess deferred income taxes.
08/19	19-G-0309 19-G-0310	NY	New York City	National Grid	Depreciation rates, net negative salvage.

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Date	Case	Jurisdict.	Party	Utility	Subject
10/19	42315	GA	Atlanta Gas Light Company	Public Interest Advocacy Staff	Capital expenditures, O&M expense, prepaid pension asset, incentive compensation, merger savings, affiliate expenses, excess deferred income taxes.
10/19	45253	IN	Duke Energy Indiana	Office of Utility Consumer Counselor	Prepaid pension asset, inventories, regulatory assets and labilities, unbilled revenues, incentive compensation, income tax expense, affiliate charges, ADIT, riders.
12/19	2019-00271	KY	Attorney General	Duke Energy Kentucky	ADIT, EDIT, CWC, payroll expense, incentive compensation expense, depreciation rates, pilot programs
05/20	202000067-EI	FL	Office of Public Counsel	Tampa Electric Company	Storm Protection Plan.
06/20	20190038-EI	FL	Office of Public Counsel	Gulf Power Company	Hurricane Michael costs.
07/20 09/20	PUR-2020-00015 Direct Surrebuttal	VA	Old Dominion Committee for Fair Utility Rates	Appalachian Power Company	Coal Amortization Rider, storm damage, prepaid pension and OPEB assets, return on joint-use assets.
07/20 09/20	2019-226-E Direct Surrebbutal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Integrated Resource Plan.
10/20	2020-00160	KY	Attorney General	Water Service Corporation of Kentucky	Return on rate base v. operating ratio.
10/20	2020-00174	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Rate base v. capitalization, Rockport UPA, prepaid pension and OPEB, cash working capital, incentive compensation, Rockport 2 depreciation expense, EDIT, AMI, grid modernization rider.
11/20 12/20	2020-125-E Direct Surrebuttal	SC	Office of Regulatory Staff	Dominion Energy South Carolina	Summer 2 and 3 cancelled plant and transmission cost recovery; TCJA; regulatory assets.
12/20	2020172-EI	FL	Office of Public Counsel	Florida Power & Light Company	Hurricane Dorian costs.
12/20	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM23, Vogtle 3 and 4 rate impact analyses.
02/21 04/21	2019-224-E 2019-225-E Direct Surrebuttal	SC	Office of Regulatory Staff	Duke Energy Carolinas, LLC, Duke Energy Progress, LLC	Integrated Resource Plans.
03/21	51611	TX	Steering Committee of Cities Served by Oncor	Sharyland Utilities, L.L.C	ADIT, capital structure, return on equity.

Expert Testimony Appearances
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Date	Case	Jurisdict.	Party	Utility	Subject
03/21	2020-00349 2020-00350	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Utilities Company and Louisville Gas and Electric Company	Rate base v. capitalization, retired plant costs, depreciation, securitization, staffing + payroll, pension + OPEB, AMI, off-system sales margins.
04/21	18-857-EL-UNC 19-1338-EL-UNC 20-1034-EL-UNC 20-1476-EL-UNC	OH	The Ohio Energy Group	First Energy Ohio Companies	Significantly Excessive Earnings Test; legacy nuclear plant costs.
05/21 06/21	2021-00004 Direct Supplemental Direct	KY	Attorney General and Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	CPCN for CCR/ELG Projects at Mitchell Plant
06/21	29849 (Panel with Philip Hayet, Tom Newsome)	GA	Georgia Public Service Commission Staff	Georgia Power Company	VCM24, Vogtle 3 and 4 rate impact analyses.

EXHIBIT___(LK-2)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 75
RESPONSIBLE PERSON: **Michelle K. Carpenter / Julia J. Tucker**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 75. For each PJM planning year 2015/2016, 2016/2017, 2017/2018, 2018/2019, 2019/2020, 2020/2021, 2021/2022, 2023/2024 and 2024/2025 please provide:

1) the amount of capacity (Company owned capacity and demand response broken out separately) in MW that the Company sold into the PJM Base Residual Auction,

2) the price it received in $/MW-day and 3) the total capacity revenue that has been or will be received.

Response 75. Please see page 2 of this response for a summary of the amount of company-owned and demand response capacity in MWs that EKPC sold or plans to sell into the PJM Base Residual and Incremental Auctions for the delivery years of 2015/2016, 2016/2017, 2017/2018, 2018/2019, 2019/2020, 2020/2021, 2021/2022, 2023/2024 and 2024/2025. This schedule also includes the associated pricing in $/MW-day and total capacity revenue that has been or is anticipated to be received. The revenue reported on this schedule is based upon the delivery year and is only for PJM billing code 2600, RPM Auction, and does not include the charges associated with purchasing the required load obligation capacity from the PJM Base Residual and Incremental Auctions. Therefore, these revenue amounts are not representative of the calendar year net capacity sales for financial reporting purposes. EKPC's Account 447251 reflects the net position of all capacity-related charges and credits associated with EKPC selling capacity into the auctions and buying capacity to cover its required load obligation volume (all PJM 2600 and 1600 series billing codes) plus any capacity purchases and/or sales revenues from other organizations.

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
EKPC PJM RPM Summary by Delivery Year (1)

	2015/2016	2016/2017		2017/2018		2018/2019		2019/2020		2020/2021	2021/2022	(4) 2022/2023	(4) 2023/2024	(4) 2024/2025
RPM Product Type	Base	Base	CP	Base	CP	Base	CP	Base	CP	CP	CP	CP	CP	CP
BRA Clearing Price ($/MW-Day)	$0.00	$59.37	$134.00	$120.00	$151.50	$149.98	$164.77	$80.00	$100.00	$76.53	$140.00	$88.40	$92.50	$94.94
BRA Generation UCAP (MW)	0.0	306.4	2,324.6	178.4	2,304.2	702.5	1,741.0	605.6	2,304.0	2,856.5	3,050.6	3,010.4	3,010.4	3,010.4
BRA Demand Response UCAP (MW)	0.0	13.9	118.6	16.4	118.5	0.0	128.4	0.0	133.8	132.7	146.3	247.6	247.6	247.6
1st Incremental Auction ($/MW-Day)	$43.00	$0.00	$0.00	$84.00	$0.00	$0.00	$0.00	$15.00	$51.33	$42.90	$23.00	$0.00	$0.00	$0.00
1st IA Cleared UCAP (MW)	382.9	0.0	0.0	4.7	0.0	0.0	0.0	2.1	29.4	0.0	0.0	0.0	0.0	0.0
1st IA Demand Response UCAP (MW)	16.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2nd Incremental Auction ($/MW-Day)	$0.00	$0.00	$0.00	$26.50	$0.00	$5.00	$50.00	$0.00	$32.87	$20.25	$10.26	$0.00	$0.00	$0.00
2nd IA Cleared UCAP (MW)	0.0	0.0	0.0	324.9	0.0	292.2	0.1	0.0	11.7	0.0	0.0	0.0	0.0	0.0
2nd IA Demand Response UCAP (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0	0.0
3rd Incremental Auction ($/MW-Day)	$100.76	$5.02	$0.00	$0.00	$0.00	$14.29	$34.99	$0.00	$0.00	$10.00	$20.55	$0.00	$0.00	$0.00
3rd IA Cleared UCAP (MW)	0.0	176.2	0.0	0.0	0.0	30.6	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3rd IA Demand Response UCAP (MW)	8.3	14.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.9	7.0	0.0	0.0	0.0
Total Generation UCAP (MW)	382.9	482.6	2,324.6	508.0	2,304.2	1,025.4	1,743.3	607.7	2,345.1	2,856.5	3,050.6	3,010.4	3,010.4	3,010.4
Total Demand Response UCAP (MW)	24.7	28.0	118.6	16.4	118.5	0.0	128.4		133.8	143.6	157.3	247.6	247.6	247.6
Total Revenue ($) (2) (3)	$6,590,273		$126,786,510		$145,704,507		$151,608,510		$107,660,065	$83,538,455	$163,429,075	$105,122,147	$109,997,722	$112,898,082

(1) PJM Delivery Year is from June through May

(2) Total Revenue represents PJM Billing Code 2600, RPM Auction for Delivery Years 2015/2016, 2016/2017, 2017/2018, 2018/2019, and 2019/2020

(3) Total Revenue for Delivery Years 2020/2021, 2021/2022, 2022/2023, 2023/2024, and 2024/2025 are estimated

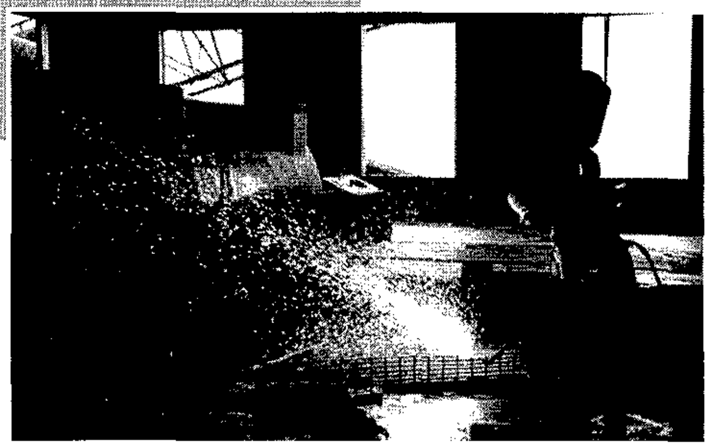
(4) BRA and Incremental Auction clearing prices are forecasted for Delivery Years 2022/2023, 2023/2024, and 2024/2025

EXHIBIT___(LK-3)

Brent Wasson, left, and Cliff Harmon discuss work being done during the Dale Station demolition.

Fuel supply and emissions

Low natural gas prices continued to impact EKPC's fuel mix with coal becoming less dominant as a fuel source. The use of coal in EKPC's generating fleet has declined from 82 percent of our generation in 2010 to 46 percent in 2019. As a result, plant emissions — including sulfur dioxide, nitrogen oxide and carbon dioxide — also continued to decline. CO2 fell by 3.55 percent from 2010 levels.



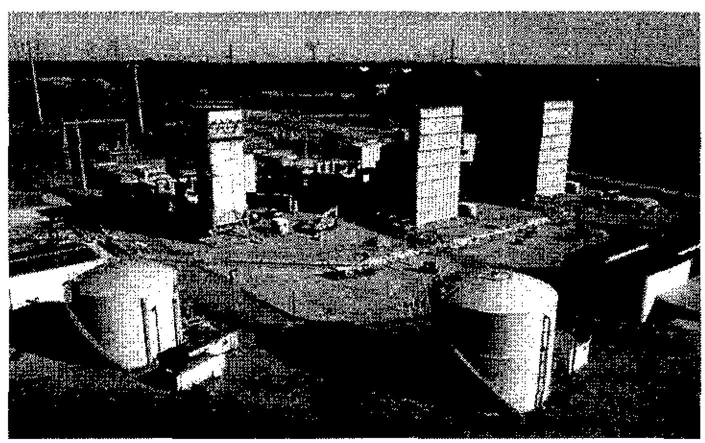
The Dale Station demolition leveled the footprint of EKPC's first power plant.

Dale Station demolition completed

A team of dedicated workers completed the demolition of Dale Station, filling and leveling the footprint where the plant stood.

The project involved the demolition of large boilers and massive brick walls, along with the meticulous cutting and collection of tons of pipes and equipment. The work completed the total reclamation and clean close of the Dale Station site.

EKPC is forever indebted to those who served at Dale Station, its first power plant, and the work they did to dramatically improve the lives of thousands of Kentuckians by safely providing reliable and affordable energy. For more than 60 years, the plant provided vital power to Kentuckians, and it was the first plant financed by the federal Rural Utilities Service.



Bluegrass Station Unit #3 became available to serve EKPC's load in 2019.

EKPC gains availability of the third Bluegrass unit

Three natural gas-fueled generating units with a net capacity of 567 megawatts operate at Bluegrass Station in Oldham County. Until May 2019, one unit was subject to a tolling agreement with a neighboring utility that received all of its energy output. With the end of that agreement, all three units are available to serve EKPC's load.

EXHIBIT___(LK-4)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 53
RESPONSIBLE PERSON: Isaac S. Scott
COMPANY: East Kentucky Power Cooperative, Inc.

Request 53. Refer to Schedule 1.07, which details the proforma adjustment normalize wages and salaries. Describe all known reasons why the "2020 Merit Increase Annualized" amount in the middle column for Transmission O&M wages and salaries amounted to a 9.6% increase over test year actual amounts ($12,796,417/$11,676,336).

Response 53. The reason for the change in the Transmission O&M wages and salaries presented on Schedule 1.07 is the result of preparing the payroll normalization based on a single payroll. As shown in Attachment 3 – Workpaper 1.07 – Wages & Salaries, the September 18, 2020 payroll was annualized in order to determine the effect of the 2020 merit increase. The allocation of the payroll costs between capital and expense accounts reflects the account allocations for that one payroll. However, over the course of a year, the allocation of each payroll's cost between accounts will fluctuate with the result at the end of a year reflecting a "blended" allocation. Thus, the change in the Transmission O&M wages and salaries between the 2020 merit increase and the test year actual is the result of the process used to annualize the payroll costs and not a specific event or circumstance.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 54
RESPONSIBLE PERSON: Isaac S. Scott
COMPANY: East Kentucky Power Cooperative, Inc.

Request 54. Refer to Schedule 1.07, which details the proforma adjustment to normalize wages and salaries. Describe all known reasons why the "2020 Merit Increase Annualized" amount in the middle column for Customer Service & Information O&M wages and salaries amounted to a 9.5% increase over test year actual amounts ($1,646,924/$1,504,128).

Response 54. The reason for the change in the Customer Service & Information O&M wages and salaries presented on Schedule 1.07 is the result of preparing the payroll normalization based on a single payroll. Please see the response to Request 53.

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 55
RESPONSIBLE PERSON: **Isaac S. Scott**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 55. Refer to Schedule 1.07, which details the proforma adjustment to normalize wages and salaries. Describe all known reasons why the "2020 Merit Increase Annualized" amount in the middle column for Administrative & General O&M wages and salaries amounted to an 11.6% increase over test year actual amounts ($14,694,317/$13,161,170).

Response 55. The reason for the change in the Administrative & General O&M wages and salaries presented on Schedule 1.07 is the result of preparing the payroll normalization based on a single payroll. Please see the response to Request 53.

EXHIBIT___(LK-5)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
FIRST REQUEST FOR INFORMATION RESPONSE

COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION DATED 3/4/21
REQUEST 23
RESPONSIBLE PERSON: **Barry Lindeman**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 23. For each employee group, state the amount, percentage increase, and effective dates for general wage increases and, separately, for merit increases granted or to be granted in the past two calendar years and the historical test period.

Response 23. See pages 2 through 5 of this response for the amount, percentage increase, and effective dates for general wage increases and, separately, for merit increases granted or to be granted in the past two calendar years and the historical test period.

Average General Increase %
and Average General Increase $
for Exempt/Non-exempt

Row Labels	Average of % Change	Average of Amount
2018		
E	5.47%	$ 5,118
N	4.18%	$ 2,019
2019		
E	4.95%	$ 5,296
N	5.79%	$ 2,435
2020		
E	5.60%	$ 5,619
N	10.30%	$ 4,532
Grand Total	**5.42%**	**$ 4,319**

Average General Increase % and Average General Increase $ for Full-time and Part-time Employees

Row Labels	Average of % Change	Average of Amount	
2018			
FT	4.48%	$	3,962
PT	6.31%	$	1,822
2019			
FT	4.65%	$	4,759
PT	9.62%	$	3,133
2020			
FT	4.76%	$	4,322
PT	20.51%	$	7,766
Grand Total	**5.42%**	**$**	**4,319**

*A few instances in FT employees with demotions which impacts averages.

*Larger increase in 2020 for PT employees due to updating pay plan for student engineers.

Average Merit Increase % and Average Increase $ for Exempt/Non-exempt

Row Labels	Average of % Change	Average of Amount	
2018			
E	3.17%	$	5,101
N	2.99%	$	2,218
2019			
E	3.38%	$	4,112
N	3.20%	$	2,431
2020			
E	3.10%	$	4,045
N	2.87%	$	2,715
Grand Total	**3.125%**	**$**	**3,506**

Average Merit Increase % and Average Increase $ for Full-time Employees

Row Labels	Average of % Change	Average of Amount
2018	3.083%	$ 3,739
2019	3.299%	$ 3,336
2020	2.996%	$ 3,442
Grand Total	**3.125%**	**$ 3,506**

*Part-time employees are not eligible for merit increases

EXHIBIT___(LK-6)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 57
RESPONSIBLE PERSON: **Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 57. Provide a copy of all source documents relied on, such as actuarial reports, to record pension and OPEB expense during 2019, 2020, and 2021 to date. In addition, provide the expense percentage, the environmental surcharge percentage, and the capital percentage used in the computations and demonstrate that the Company did not include benefits costs that normally would be capitalized or reflected as environmental surcharge related as expense amounts.

Response 57. Please see pages 3 through 45 of this response for copies of Mercer's ASC 715 Actuarial Valuation Reports on EKPC's postretirement benefits (health and life) as of December 31, 2019 and 2020, which provide the net periodic benefit cost for each respective year. The 2020 report also includes the estimated net periodic benefit cost for the year ending December 31, 2021. Each year, the estimated net periodic benefit cost is recorded over twelve months with the monthly amount allocated to capital and expense based upon each respective month's labor distribution. The labor distribution is also detailed at the project level, which means the environmental surcharge is only allocated this cost in proportion to labor charged to eligible projects. Since the allocation of this cost is based upon labor, the resulting percentages charged to capital, environmental surcharge, and expense vary from month to month. Listed below are the annualized percentages for 2019, 2020, and for the four months ended April 30, 2021.

	2019	**2020**	**2021 YTD**
Net Periodic Benefit Cost	$ 3,280,634.00	$ 1,057,933.00	$ 180,342.64
Expense Percentage	93.21%	91.44%	92.79%
Environmental Surcharge Percentage	2.24%	3.90%	4.41%
Capital Percentage	4.55%	4.66%	2.80%
Total	100.00%	100.00%	100.00%

EKPC participates in a multiemployer-defined benefit pension plan and defined contribution plans. Therefore, there are no actuarial reports relied upon to record expense. Contributions are allocated to capital and expense based upon each month's labor distribution, as described above.

EXHIBIT___(LK-7)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 61
RESPONSIBLE PERSON: **Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 61. Refer to Exhibit ISS-1 Schedule 1.23. Provide the amounts of the highest cost exclusion and disallowed forced outage amounts for 2020.

Response 61. For the year ended December 31, 2020, the fuel adjustment clause highest-cost exclusion and disallowed forced outages were $308,974 and $68,386, respectively.

EXHIBIT___(LK-8)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 62
RESPONSIBLE PERSON: Michelle K. Carpenter
COMPANY: East Kentucky Power Cooperative, Inc.

Request 62. Refer to Exhibit ISS-1 Schedule 1.23. Describe all known reasons why the highest cost exclusion amount for 2015 of $6,757,298 was almost double that for any other listed year.

Response 62. Nearly half of the $6,757,298 highest-cost exclusion for 2015 occurred in February 2015, which was due to extremely cold temperatures occurring throughout the Eastern connection. Both EKPC and PJM set all-time winter peaks on February 20, 2015 at hour ending 0800. Increased demand in the PJM footprint drove up hourly market prices well beyond EKPC's highest-cost units available.

EXHIBIT___(LK-9)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 17
RESPONSIBLE PERSON: **Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 17. Provide a history of maintenance expense by generating unit by O&M expense account for each year 2011 through 2020. Provide the major outage maintenance as a subset of the expense by generating unit by O&M expense account. Provide a description of the scope of each such outage and the normal frequency for the scope of each such outage, including whether it was a one-time or unusual event.

Response 17. Please refer to pages 2 through 5 of this response and corresponding Excel file *AG Nucor DR2 Response 17.xlsx* for a summary of maintenance expense by generating unit, by O&M expense account, for each year 2011 through 2020. EKPC's historical accounting records were not maintained to separately identify those costs within maintenance expense that represent major maintenance. However, please refer to Responses 16b and 16c for information derived from EKPC's Production maintenance records related to major maintenance projects by generating unit, along with descriptions of the scope of work and expected frequency of such outages.

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Plant, Operating Unit, Account and Subaccount

Production Maint by Account/Oper Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
510000 - Maint. Supv/Engr-Steam Gen	160,814.77	114,573.99	93,905.37	133,450.41	130,062.48	147,512.09	153,676.86	148,989.97	28,211.13	16,305.31
511000 - Maint. of Structures-Steam Gen	1,256,638.73	1,435,242.86	684,233.35	1,198,545.50	1,200,684.92	1,316,763.30	1,681,955.13	1,248,357.54	811,860.55	803,304.23
512000 - Maint. of Boiler Plant-Steam Gen	4,334,298.56	3,505,960.34	3,906,015.04	3,998,355.65	3,463,705.59	2,787,419.99	2,470,505.05	3,419,440.03	2,234,539.89	1,385,899.62
513000 - Maint. of Elec Plant-Steam Gen	898,141.31	1,232,830.44	572,426.85	882,449.57	763,265.61	685,388.23	1,368,588.18	600,758.23	990,961.29	573,066.54
CP00 - Cooper Station-Common Total	**6,649,893.37**	**6,288,607.63**	**5,256,580.61**	**6,212,801.13**	**5,557,718.60**	**4,937,083.61**	**5,674,725.22**	**5,417,545.77**	**4,065,572.86**	**2,778,575.70**
511000 - Maint. of Structures-Steam Gen	735.68	1,521.34	166,385.15	3,082.18	66,324.43	17,147.92	10,370.10	3,921.17	2,775.99	741.92
512000 - Maint. of Boiler Plant-Steam Gen	424,304.39	168,727.41	854,308.03	744,826.23	1,104,100.15	1,216,778.16	955,980.33	1,165,294.01	1,106,371.48	575,564.66
513000 - Maint. of Elec Plant-Steam Gen	152,251.30	73,584.41	30,971.21	719,306.77	162,058.66	399,644.05	210,174.19	78,056.54	994,994.96	146,989.78
CP01 - Cooper-Unit 1 Total	**577,291.37**	**243,833.16**	**1,051,664.39**	**1,467,215.18**	**1,332,483.24**	**1,633,570.13**	**1,176,524.62**	**1,247,271.72**	**2,104,142.43**	**723,296.36**
511000 - Maint. of Structures-Steam Gen	8,831.71	492.40	52,120.00	-	783.22	274.05	15,413.09	70,816.78	87,910.31	1,270.75
512000 - Maint. of Boiler Plant-Steam Gen	500,449.18	2,315,341.67	553,123.61	1,230,991.71	1,053,822.94	1,146,796.79	977,303.16	2,553,762.31	799,992.83	220,199.27
513000 - Maint. of Elec Plant-Steam Gen	505,500.96	2,863,905.25	161,010.03	67,562.49	78,826.60	88,688.83	1,065,064.84	829,707.11	365,663.87	376,451.32
CP02 - Cooper-Unit 2 Total	**1,014,781.85**	**5,179,739.32**	**766,253.64**	**1,298,554.20**	**1,133,432.76**	**1,235,759.67**	**2,057,781.09**	**3,454,286.20**	**1,253,567.01**	**597,921.34**
511000 - Maint. of Structures-Steam Gen	-	-	-	-	353.49	-	-	-	-	-
512000 - Maint. of Boiler Plant-Steam Gen	-	130,027.23	584,760.76	825,226.53	568,709.70	526,177.73	1,207,234.00	767,251.68	679,988.13	677,403.26
CP22 - Cooper-Scrubber 2 Total	**-**	**130,027.23**	**584,760.76**	**825,226.53**	**569,063.19**	**526,177.73**	**1,207,234.00**	**767,251.68**	**679,988.13**	**677,403.26**
510000 - Maint. Supv/Engr-Steam Gen	748,827.38	741,888.75	401,455.63	144,587.75	141,426.25	52,444.13	-	-	-	-
511000 - Maint. of Structures-Steam Gen	213,799.85	205,829.39	119,429.89	68,616.71	24,743.70	6,990.85	-	-	-	-
512000 - Maint. of Boiler Plant-Steam Gen	2,614,425.22	1,288,197.09	544,242.14	325,815.93	426,873.79	26,153.31	-	-	-	-
513000 - Maint. of Elec Plant-Steam Gen	287,192.28	341,387.77	55,621.37	70,458.70	30,906.26	1,899.36	-	-	-	-
DA00 - Dale Station-Common Total	**3,864,244.73**	**2,577,303.00**	**1,120,749.03**	**609,479.09**	**623,950.00**	**87,487.65**	**-**	**-**	**-**	**-**
512000 - Maint. of Boiler Plant-Steam Gen	25,992.53	8,253.60	-	-	-	-	-	-	-	-
DA01 - Dale-Unit 1 Total	**25,992.53**	**8,253.60**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
512000 - Maint. of Boiler Plant-Steam Gen	-	264.37	-	-	-	-	-	-	-	-
DA03 - Dale-Unit 3 Total	**-**	**264.37**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
512000 - Maint. of Boiler Plant-Steam Gen	-	-	106.15	259.66	-	-	-	-	-	-
DA04 - Dale-Unit 4 Total	**-**	**-**	**106.15**	**259.66**	**-**	**-**	**-**	**-**	**-**	**-**
553000 - Maint. of Gen&Elec Equip-Oth Gen	1,213.22	1,983.71	9,783.25	28,493.12	4,235.37	-	-	-	-	-
DG00 - Diesel Generator-Common Total	**1,213.22**	**1,983.71**	**9,783.25**	**28,493.12**	**4,235.37**	**-**	**-**	**-**	**-**	**-**
553000 - Maint. of Gen&Elec Equip-Oth Gen	(67.39)	2,161.71	110.20	-	7,148.65	17,965.07	5,809.06	24,604.81	76,555.06	14,044.64
DG01 - Cooper Diesel Generator Total	**(67.39)**	**2,161.71**	**110.20**	**-**	**7,148.65**	**17,965.07**	**5,809.06**	**24,604.81**	**76,555.06**	**14,044.64**
553000 - Maint. of Gen&Elec Equip-Oth Gen	12,059.01	10,281.76	15,013.42	90,351.17	35,549.23	32,841.10	57,802.94	36,126.91	98,104.36	31,854.50
DG02 - Cagle's Diesel Generator Total	**12,059.01**	**10,281.76**	**15,013.42**	**90,351.17**	**35,549.23**	**32,841.10**	**57,802.94**	**36,126.91**	**98,104.36**	**31,854.50**
551000 - Maint. Supv/Engr-Oth Power Gen	4.93	-	-	-	-	-	-	-	-	-
552000 - Maint. of Structures-Oth Pwr Gen	10,356.49	-	-	-	2,890.80	-	7,883.40	-	3,546.51	224,847.70
553000 - Maint. of Gen&Elec Equip-Oth Gen	361,965.82	192,522.28	240,589.90	204,864.57	143,650.94	304,230.52	336,934.83	165,421.33	283,825.35	370,271.00
LF01 - Green Valley LFGTE Total	**372,327.24**	**192,522.28**	**240,589.90**	**204,864.57**	**146,541.74**	**304,230.52**	**344,818.23**	**165,421.33**	**287,371.86**	**595,118.70**

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Plant, Operating Unit, Account and Subaccount

Production Maint by Account/Oper Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
552000 - Maint. of Structures-Oth Pwr Gen	-	-	-	-	-	-	3,816.00	-	96,000.00	69,988.22
553000 - Maint. of Gen&Elec Equip-Oth Gen	290,169.19	489,475.00	344,199.46	245,098.39	236,926.80	450,773.87	250,243.63	274,670.96	731,626.71	266,247.83
LF02 - Laurel Ridge LFGTE Total	**290,169.19**	**489,475.00**	**344,199.46**	**245,098.39**	**236,926.80**	**450,773.87**	**254,059.63**	**274,670.96**	**827,626.71**	**336,236.05**
551000 - Maint. Supv/Engr-Oth Power Gen	179.40	-	-	-	-	-	-	-	-	-
552000 - Maint. of Structures-Oth Pwr Gen	-	-	-	-	-	-	-	-	16,724.65	150,247.13
553000 - Maint. of Gen&Elec Equip-Oth Gen	264,506.44	335,948.53	207,651.40	391,578.02	381,250.46	614,174.62	648,351.96	560,993.62	827,482.73	714,746.10
LF03 - Bavarian LFGTE Total	**264,685.84**	**335,948.53**	**207,651.40**	**391,578.02**	**381,250.46**	**614,174.62**	**648,351.96**	**560,993.62**	**844,207.38**	**864,993.23**
551000 - Maint. Supv/Engr-Oth Power Gen	933.60	-	-	-	-	-	-	-	-	-
552000 - Maint. of Structures-Oth Pwr Gen	-	160.46	-	-	2,350.57	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	211,854.04	483,355.72	189,084.69	171,932.81	157,115.14	333,090.74	46,891.48	88,202.33	44,298.79	213,938.04
LF04 - Hardin County LFGTE Total	**212,787.64**	**483,516.18**	**189,084.69**	**171,932.81**	**159,465.71**	**333,090.74**	**46,891.48**	**88,202.33**	**44,298.79**	**213,938.04**
551000 - Maint. Supv/Engr-Oth Power Gen	382.80	-	-	-	-	-	-	-	-	-
552000 - Maint. of Structures-Oth Pwr Gen	-	-	-	-	-	5,492.75	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	171,884.33	202,666.42	644,165.46	211,844.49	212,998.08	391,255.30	168,445.63	107,909.24	359,287.69	715,089.86
LF05 - Pendleton County LFGTE Total	**172,267.13**	**202,666.42**	**644,165.46**	**211,844.49**	**212,998.08**	**396,748.05**	**168,445.63**	**107,909.24**	**359,287.69**	**715,089.86**
552000 - Maint. of Structures-Oth Pwr Gen	-	-	-	-	-	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	21,588.83	22,971.22	(2,940.85)	-	108.80	-	-	-	-	-
LF06 - Mason County LFGTE Total	**21,588.83**	**22,971.22**	**(2,940.85)**	**-**	**108.80**	**-**	**-**	**-**	**-**	**-**
413200 - Maint. Exp Plnt Lease Oth	-	-	-	-	-	45,580.33	45,835.05	65,640.57	78,467.91	73,897.89
553000 - Maint. of Gen&Elec Equip-Oth Gen	-	-	-	-	-	-	-	-	-	-
LF07 - Glasgow LFGTE Total	**-**	**-**	**-**	**-**	**-**	**45,580.33**	**45,835.05**	**65,640.57**	**78,467.91**	**73,897.89**
413200 - Maint. Exp Plnt Lease Oth	-	-	-	-	-	217,337.16	365,077.18	311,040.50	113,989.09	-
551000 - Maint. Supv/Engr-Oth Power Gen	-	-	-	-	-	45,988.09	76,380.05	112,345.00	158,507.12	179,742.98
552000 - Maint. of Structures-Oth Pwr Gen	-	-	-	-	-	22,848.33	312,667.40	235,570.71	250,757.81	138,787.09
553000 - Maint. of Gen&Elec Equip-Oth Gen	-	-	-	-	-	365,837.70	340,858.48	274,165.26	430,497.09	1,077,563.37
OC00 - Bluegrass Oldham Co-Common Total	**-**	**-**	**-**	**-**	**-**	**652,011.28**	**1,094,983.11**	**933,121.47**	**953,751.11**	**1,396,093.44**
553000 - Maint. of Gen&Elec Equip-Oth Gen	-	-	-	-	19.16	36,175.10	156,647.99	217,562.89	202,496.27	187,235.64
OC01 - Bluegrass Oldham Co-1 Total	**-**	**-**	**-**	**-**	**19.16**	**36,175.10**	**156,647.99**	**217,562.89**	**202,496.27**	**187,235.64**
553000 - Maint. of Gen&Elec Equip-Oth Gen	-	-	-	-	19.16	28,925.58	432,592.03	228,369.13	365,360.36	383,748.02
OC02 - Bluegrass Oldham Co-2 Total	**-**	**-**	**-**	**-**	**19.16**	**28,925.58**	**432,592.03**	**228,369.13**	**365,360.36**	**383,748.02**
413200 - Maint. Exp Plnt Lease Oth	-	-	-	-	-	235,378.03	(86,479.66)	180,609.72	37,396.94	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	-	-	-	-	19.17	-	-	-	737,510.35	135,343.88
OC03 - Bluegrass Oldham Co-3 Total	**-**	**-**	**-**	**-**	**19.17**	**235,378.03**	**(86,479.66)**	**180,609.72**	**774,907.29**	**135,343.88**
553000 - Maint. of Gen&Elec Equip-Oth Gen	-	-	-	-	-	-	-	16,061.70	38,725.32	31,556.57
SF01 - Solar Facility-Coop 1 Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**16,061.70**	**38,725.32**	**31,556.57**

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Plant, Operating Unit, Account and Subaccount

Production Maint by Account/Oper Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
512000 - Maint. of Boiler Plant-Steam Gen	-	-	-	-	-	-	12,424.96	223,067.78	254,883.13	78,557.86
551000 - Maint. Supv/Engr-Oth Power Gen	-	-	-	3,232.50	2,298.88	74,961.00	249,387.18	251,665.22	258,097.04	352,276.77
552000 - Maint. of Structures-Oth Pwr Gen	88,943.21	116,836.28	107,398.89	115,633.83	449,634.21	711,495.24	696,949.87	666,455.48	461,289.11	521,002.31
553000 - Maint. of Gen&Elec Equip-Oth Gen	829,303.99	995,688.92	556,389.34	1,731,267.08	579,322.87	490,940.85	497,598.04	1,024,411.02	701,187.73	746,268.13
SM50 - Smith CT's-Common Total	**918,247.20**	**1,112,525.20**	**663,788.23**	**1,850,133.41**	**1,031,255.96**	**1,277,397.09**	**1,456,360.05**	**2,165,599.50**	**1,675,457.01**	**1,698,105.07**
552000 - Maint. of Structures-Oth Pwr Gen	13,231.95	7,884.21	28,317.78	9,094.25	1,464.54	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	47,826.12	138,578.56	205,031.19	67,117.21	191,215.01	2,671,697.19	105,048.75	21,743.38	120,790.61	100,568.20
SM51 - Smith CT-Unit 1 Total	**61,058.07**	**146,462.77**	**233,348.97**	**76,211.46**	**192,679.55**	**2,671,697.19**	**105,048.75**	**21,743.38**	**120,790.61**	**100,568.20**
552000 - Maint. of Structures-Oth Pwr Gen	40.73	1,729.29	221.46	106.41	-	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	46,720.07	353,654.60	263,349.82	154,710.97	546,776.07	183,932.33	453,735.60	964,573.50	737,068.12	383,339.45
SM52 - Smith CT-Unit 2 Total	**46,760.80**	**355,383.89**	**263,571.28**	**154,817.38**	**546,776.07**	**183,932.33**	**453,735.60**	**964,573.50**	**737,068.12**	**383,339.45**
552000 - Maint. of Structures-Oth Pwr Gen	1,976.54	583.73	1,766.04	1,510.31	849.36	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	63,434.07	869,762.17	586,759.08	(107,416.18)	69,371.61	135,560.67	124,080.07	4,733,919.68	490,756.97	100,936.39
SM53 - Smith CT-Unit 3 Total	**65,410.61**	**870,345.90**	**588,525.12**	**(105,905.87)**	**70,220.97**	**135,560.67**	**124,080.07**	**4,733,919.68**	**490,756.97**	**100,936.39**
552000 - Maint. of Structures-Oth Pwr Gen	1,343.84	771.34	13,663.21	330.90	1,227.94	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	39,104.53	257,575.46	73,108.62	717,840.83	197,238.08	173,804.12	93,590.68	67,219.88	179,356.60	73,519.77
SM54 - Smith CT-Unit 4 Total	**40,448.37**	**258,346.80**	**86,771.83**	**718,171.73**	**198,466.02**	**173,804.12**	**93,590.68**	**67,219.88**	**179,356.60**	**73,519.77**
552000 - Maint. of Structures-Oth Pwr Gen	6,956.67	2,735.30	4,091.14	275.84	298.81	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	19,567.08	230,956.30	49,738.27	292,613.15	934,440.66	140,541.52	209,084.52	146,872.82	514,052.36	58,569.99
SM55 - Smith CT-Unit 5 Total	**26,523.75**	**233,691.60**	**53,829.41**	**292,888.99**	**934,739.47**	**140,541.52**	**209,084.52**	**146,872.82**	**514,052.36**	**58,569.99**
552000 - Maint. of Structures-Oth Pwr Gen	1,004.94	1,037.37	4,928.75	3,325.54	978.93	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	46,818.85	47,413.29	424,885.68	119,891.52	1,449,070.20	255,723.80	(110,696.78)	766,539.78	191,928.70	356,497.96
SM56 - Smith CT-Unit 6 Total	**47,823.79**	**48,450.66**	**429,814.43**	**123,217.06**	**1,450,049.13**	**255,723.80**	**(110,696.78)**	**766,539.78**	**191,928.70**	**356,497.96**
552000 - Maint. of Structures-Oth Pwr Gen	6,242.31	7,754.86	3,892.50	138.73	716.50	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	79,889.50	460,079.54	490,932.49	19,985.86	119,105.05	171,824.23	1,380,599.39	143,846.30	499,976.55	92,865.00
SM57 - Smith CT-Unit 7 Total	**86,131.81**	**467,834.40**	**494,824.99**	**20,124.59**	**119,821.55**	**171,824.23**	**1,380,599.39**	**143,846.30**	**499,976.55**	**92,865.00**
552000 - Maint. of Structures-Oth Pwr Gen	5,650.24	5,575.73	7,992.09	7,888.69	105.52	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	159,502.45	29,622.44	1,823,792.75	(104,533.87)	788,065.79	536,941.00	235,529.92	724,807.59	416,349.13	241,347.81
SM59 - Smith CT-Unit 9 Total	**165,152.69**	**35,198.17**	**1,831,784.84**	**(96,645.18)**	**788,171.31**	**536,941.00**	**235,529.92**	**724,807.59**	**416,349.13**	**241,347.81**
552000 - Maint. of Structures-Oth Pwr Gen	2,705.95	2,896.25	5,744.33	41,513.08	4,440.12	-	-	-	-	-
553000 - Maint. of Gen&Elec Equip-Oth Gen	130,838.10	(62,400.51)	157,673.93	529,653.99	573,890.97	463,448.58	389,983.94	621,769.94	718,551.56	920,274.91
SM60 - Smith CT-Unit 10 Total	**133,544.05**	**(59,504.26)**	**163,418.26**	**571,167.07**	**578,331.09**	**463,448.58**	**389,983.94**	**621,769.94**	**718,551.56**	**920,274.91**
510000 - Maint. Supv/Engr-Steam Gen	1,264,319.41	1,237,840.49	1,358,775.58	2,560,484.75	2,758,678.66	3,025,836.48	2,998,718.19	3,048,985.59	3,282,613.81	3,397,261.11
511000 - Maint. of Structures-Steam Gen	3,329,719.04	4,685,289.86	4,084,390.35	5,505,151.84	4,709,871.28	4,300,825.35	4,851,922.34	4,361,886.69	5,013,428.30	4,277,521.96
512000 - Maint. of Boiler Plant-Steam Gen	5,774,832.16	7,161,561.59	8,010,357.93	7,235,548.16	6,116,203.89	7,199,241.52	7,089,926.93	8,964,566.26	6,285,494.39	6,295,966.63
513000 - Maint. of Elec Plant-Steam Gen	230,614.59	488,211.78	393,768.21	144,981.81	413,562.27	317,421.42	135,904.09	311,557.05	494,809.42	351,126.69
SP00 - Spurlock Station-Common Total	**10,599,485.20**	**13,572,903.72**	**13,847,292.07**	**15,446,166.56**	**13,998,316.10**	**14,843,324.77**	**15,076,471.55**	**16,686,995.59**	**15,076,345.92**	**14,321,876.39**

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Plant, Operating Unit, Account and Subaccount

Production Maint by Account/Oper Unit	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
511000 - Maint. of Structures-Steam Gen	20,015.45	24,855.33	2,963.07	-	44,062.65	367.34	9,115.41	279,204.73	328,840.23	305.90
512000 - Maint. of Boiler Plant-Steam Gen	4,379,182.70	2,771,127.37	5,638,197.13	5,305,197.93	5,740,465.97	5,821,595.84	5,495,824.37	6,537,277.46	7,396,304.65	6,653,977.43
513000 - Maint. of Elec Plant-Steam Gen	485,473.47	668,530.53	6,890,516.91	1,397,902.22	1,587,082.58	1,026,080.74	755,773.74	2,245,062.81	2,076,204.65	2,137,047.39
SP01 - Spurlock-Unit 1 Total	**4,884,671.62**	**3,464,513.23**	**12,531,677.11**	**6,703,100.15**	**7,371,611.20**	**6,848,043.92**	**6,260,713.52**	**9,061,545.00**	**9,801,349.53**	**8,791,330.72**
511000 - Maint. of Structures-Steam Gen	5,254.90	99,180.71	1,059.61	91,470.14	34,984.38	211.32	6,908.56	9,100.00	-	44,524.71
512000 - Maint. of Boiler Plant-Steam Gen	5,156,238.07	9,384,142.26	5,826,961.90	9,728,149.63	11,205,460.63	8,209,742.43	13,662,193.66	11,187,093.19	12,773,635.83	13,441,390.16
513000 - Maint. of Elec Plant-Steam Gen	511,347.81	2,882,087.27	1,217,970.07	1,110,547.23	594,752.91	1,759,898.49	7,418,912.38	1,780,251.26	3,081,445.77	1,787,261.30
SP02 - Spurlock-Unit 2 Total	**5,672,840.78**	**12,365,410.24**	**7,045,991.58**	**10,930,167.00**	**11,835,197.92**	**9,969,852.24**	**21,088,014.60**	**12,976,444.45**	**15,855,081.60**	**15,273,176.17**
511000 - Maint. of Structures-Steam Gen	97,067.03	54,001.78	39,100.62	69,256.30	37,566.74	346.01	44,775.76	2,041.90	24,573.33	1,012.42
512000 - Maint. of Boiler Plant-Steam Gen	7,745,770.31	5,700,678.68	6,781,539.78	9,354,938.74	9,074,993.21	8,395,940.75	10,093,234.19	9,496,747.34	9,792,131.57	6,865,222.17
513000 - Maint. of Elec Plant-Steam Gen	269,662.64	602,902.59	561,832.32	610,686.63	4,848,931.20	922,283.87	807,420.27	1,022,406.02	770,954.86	1,946,508.08
SP03 - Spurlock-Unit 3 Total	**8,112,499.98**	**6,357,583.05**	**7,382,472.72**	**10,034,881.67**	**13,961,491.15**	**9,318,570.63**	**10,945,430.22**	**10,521,195.26**	**10,587,659.76**	**8,812,742.67**
510000 - Maint. Supv/Engr-Steam Gen	-	330.60	-	-	-	-	-	-	-	-
511000 - Maint. of Structures-Steam Gen	21,220.82	58,231.30	63,962.93	12,422.31	12,057.84	1,060.23	825.95	-	17,299.29	6,731.40
512000 - Maint. of Boiler Plant-Steam Gen	4,667,001.48	3,797,934.31	3,887,903.07	7,511,857.95	7,248,647.83	6,583,544.05	7,421,241.05	7,693,226.50	9,384,211.29	8,891,147.39
513000 - Maint. of Elec Plant-Steam Gen	301,344.57	326,988.93	300,263.32	1,133,890.29	604,148.51	694,404.39	548,874.80	600,865.55	2,134,925.67	1,090,508.34
SP04 - Spurlock-Unit 4 Total	**4,989,566.87**	**4,183,485.14**	**4,252,129.32**	**8,658,170.55**	**7,864,854.18**	**7,279,008.67**	**7,970,941.80**	**8,294,092.05**	**11,536,436.25**	**9,988,387.13**
511000 - Maint. of Structures-Steam Gen	-	1,053.46	-	-	-	-	-	-	-	-
512000 - Maint. of Boiler Plant-Steam Gen	566,864.34	227,772.35	28,612.62	91,711.23	583,148.05	801,649.35	783,999.22	1,273,687.10	1,773,048.88	835,722.10
SP20 - Spurlock Scrubbers-Common Total	**566,864.34**	**228,825.81**	**28,612.62**	**91,711.23**	**583,148.05**	**801,649.35**	**783,999.22**	**1,273,687.10**	**1,773,048.88**	**835,722.10**
512000 - Maint. of Boiler Plant-Steam Gen	1,078,155.15	1,532,049.21	1,325,179.27	1,575,498.99	1,853,927.51	1,436,908.55	1,452,661.39	1,497,906.64	1,816,661.08	1,703,644.17
513000 - Maint. of Elec Plant-Steam Gen	-	-	-	-	28.79	-	-	-	-	-
SP21 - Spurlock-Scrubber 1 Total	**1,078,155.15**	**1,532,049.21**	**1,325,179.27**	**1,575,498.99**	**1,853,956.30**	**1,436,908.55**	**1,452,661.39**	**1,497,906.64**	**1,816,661.08**	**1,703,644.17**
512000 - Maint. of Boiler Plant-Steam Gen	2,899,627.96	2,211,318.55	2,922,474.20	3,038,265.30	2,362,679.93	2,667,872.32	2,135,758.60	2,822,339.68	2,601,264.51	2,825,230.87
SP22 - Spurlock-Scrubber 2 Total	**2,899,627.96**	**2,211,318.55**	**2,922,474.20**	**3,038,265.30**	**2,362,679.93**	**2,667,872.32**	**2,135,758.60**	**2,822,339.68**	**2,601,264.51**	**2,825,230.87**
Grand Total	**53,874,047.60**	**63,554,379.20**	**64,573,277.76**	**71,839,840.45**	**76,142,696.07**	**70,744,074.06**	**83,337,329.42**	**87,276,748.19**	**87,646,565.68**	**76,334,481.89**

EXHIBIT___(LK-10)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 19
RESPONSIBLE PERSON: **Isaac S. Scott / Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 19. Refer to the response to AG-Nucor 1-31.

Request 19a. Indicate whether the amounts reflected in the excel file entitled "AG_NUCOR_DR1_Response 31.xlsx" reflect outage maintenance expenses "as incurred" or reductions for deferrals and increases for amortizations. If the latter, then provide a version of the spreadsheet that shows the expenses as incurred, the deferrals, and the amortizations.

Response 19a. The amounts reflected in Response 31 represent maintenance expenses for Generally Accepted Accounting Principles ("GAAP") financial reporting purposes, meaning the amounts shown exclude expenses incurred that were granted regulatory asset treatment and include any subsequent amortization of regulatory assets. Please refer to pages 6 and 7 of this response, along with corresponding Excel file *AG Nucor DR2 Response 19.xlsx, Tab 19a,* which takes the original schedule provided and removes the impact of the major maintenance regulatory asset to arrive at maintenance costs incurred for each year.

Request 19b. Provide an expanded version of the excel file entitled "AG_NUCOR_DR1_Response 31.xlsx" as modified by the response to part (a) that reflects the amounts included in the test year after proforma adjustments, including deferrals and amortizations.

Response 19b. Please refer to pages 8 through 10 and corresponding Excel file *AG Nucor DR2 Response 19.xlsx, Tab 19b* for a version of the schedule provided in Response 19a that excludes Account 413200, Maintenance Expense, Plant Leased to Others. The 2019 maintenance expense on this file corresponds to the production maintenance expense shown on Mr. Scott's Exhibit ISS-1. For RUS reporting purposes and Exhibit ISS-1, all leased plant activity is shown as a net number on one line item, Income Leased Property-Net. However, production maintenance expense on Exhibit ISS-1 should have also included the Exhibit ISS-1, Schedule 1.26 proposed amortization adjustment of $905,523 for the Spurlock major maintenance regulatory asset. It appears that this adjustment was inadvertently shown as an adjustment to Depreciation and Amortization on Schedule 1.00, Summary of Proposed Proforma Adjustments. EKPC typically charges the amortization of regulatory assets to the account that would normally be expensed, which in this case, is maintenance. Therefore, the proposed test year production maintenance expense balance should be comprised of the balance from Exhibit ISS-1 of $87,416,712 plus the $905,523 regulatory asset amortization adjustment to come to a total of $88,322,235.

Request 19c. Explain why the Company did not propose a normalized generation maintenance expense based on an average of actual historic years.

Response 19c. In filing a rate application utilizing a historic test year, EKPC focused on proposing adjustments that reflected known and measurable events or results. EKPC did propose adjustments based on an average of historic years for forced outage and highest purchased power costs not recoverable through the FAC, as it believed such adjustments had been considered and accepted previously by the Commission. EKPC did not consider applying a similar approach to its generation maintenance expense.

Also, please refer to pages 6 and 7 of this response. When comparing maintenance expense to maintenance costs incurred in 2019, you will notice that the major maintenance regulatory asset granted in 2019 in essence normalized EKPC's maintenance expense to a level that was comparable to prior years.

Request 19d. Confirm that the Company's generation maintenance expense varies significantly for each generating unit over a five year or longer period based on the detail provided in this response. For example, the total generation maintenance expense incurred in the test year was $87.6 million, but in 2020 was $76.3 million. If confirmed, then explain the reasons why the expense for each generating unit varies from year to year and the effect that major outage maintenance has on the variation from year to year.

Response 19d. EKPC confirms that generation maintenance expense can vary significantly from year to year depending upon where each unit is in its major maintenance cycle and if any unanticipated equipment failures occur that require maintenance in a given year, all of which are outside of routine maintenance. However, it should be noted that EKPC does not believe that production maintenance expense for 2020 is a representative year for comparison purposes. Several projects, including a scheduled major overhaul, were deferred or cancelled due to COVID-19.

Request 19e. Indicate if the Company is opposed or in favor of a normalized generation maintenance outage expense based on an average of actual historic years similar to that adopted by the Commission for Kentucky Power Company, Kentucky Utilities Company, and Louisville Gas and Electric Company. Provide a proposal and calculation of a normalized maintenance outage expense if the Commission were to consider such an adjustment in this proceeding.

Response 19e. EKPC is not familiar enough with the referenced normalization expense mechanisms to be either opposed to or in favor of such a mechanism. It would have helped EKPC's preparation of a response to this request if the specific case number references establishing these mechanisms and any subsequent modifications had been provided. EKPC would be willing to consider such a mechanism once it has had time to review and evaluate the mechanisms approved for Kentucky Power Company, Kentucky Utilities Company, and Louisville Gas & Electric Company. EKPC is aware that many of the rate cases for the listed utilities have utilized a forecasted test year. This fact may have a bearing on whether the normalization mechanism is appropriate for EKPC. In addition, EKPC is aware that many of the rate cases for the listed utilities have been resolved with settlement or stipulation agreements. These settlement or stipulation agreements usually contain provisions stating that the agreement has no precedential value and that the agreement cannot be cited as support in any other proceeding.

As EKPC has not determined it would be in favor of such an adjustment, it is unable, and not appropriate for it, to provide a proposal and calculation of a normalized maintenance outage expense adjustment at this time.

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Account, Subaccount, Plant and Operating Unit

Production Maint by Account/Oper Unit	2016	2017	2018	2019	2020
LF07 - Glasgow LFGTE	45,580.33	45,835.05	65,640.57	78,467.91	73,897.89
OC00 - Bluegrass Oldham Co-Common	217,337.16	365,077.18	311,040.50	113,989.09	-
OC03 - Bluegrass Oldham Co-3	235,378.03	(86,479.66)	180,609.72	37,396.94	-
413200 - Maint. Exp Plant Lease Oth Total	**498,295.52**	**324,432.57**	**557,290.79**	**229,853.94**	**73,897.89**
CP00 - Cooper Station-Common	147,512.09	153,676.86	148,989.97	28,211.13	16,305.31
DA00 - Dale Station-Common	52,444.13	-	-	-	-
SP00 - Spurlock Station-Common	3,025,836.48	2,998,718.19	3,048,985.59	3,282,613.81	3,397,261.11
510000 - Maint. Supv/Engr-Steam Gen	**3,225,792.70**	**3,152,395.05**	**3,197,975.56**	**3,310,824.94**	**3,413,566.42**
CP00 - Cooper Station-Common	1,316,763.30	1,681,955.13	1,248,357.54	811,860.55	803,304.23
CP01 - Cooper-Unit 1	17,147.92	10,370.10	3,921.17	2,775.99	741.92
CP02 - Cooper-Unit 2	274.05	15,413.09	70,816.78	87,910.31	1,270.75
DA00 - Dale Station-Common	6,990.85	-	-	-	-
SP00 - Spurlock Station-Common	4,300,825.35	4,851,922.34	4,361,886.69	5,013,428.30	4,277,521.96
SP01 - Spurlock-Unit 1	367.34	9,115.41	279,204.73	328,840.23	305.90
SP02 - Spurlock-Unit 2	211.32	6,908.56	9,100.00	-	44,524.71
SP03 - Spurlock-Unit 3	346.01	44,775.76	2,041.90	24,573.33	1,012.42
SP04 - Spurlock-Unit 4	1,060.23	825.95	-	17,299.29	6,731.40
SP20 - Spurlock Scrubbers-Common	-	-	-	-	-
511000 - Maint. of Structures-Steam Gen	**5,643,986.37**	**6,621,286.34**	**5,975,328.81**	**6,286,688.00**	**5,135,413.29**
CP00 - Cooper Station-Common	2,787,419.99	2,470,505.05	3,419,440.03	2,234,539.89	1,385,899.62
CP01 - Cooper-Unit 1	1,216,778.16	955,980.33	1,165,294.01	1,106,371.48	575,564.66
CP02 - Cooper-Unit 2	1,146,796.79	977,303.16	2,553,762.31	799,992.83	220,199.27
CP22 - Cooper-Scrubber 2	526,177.73	1,207,234.00	767,251.68	679,988.13	677,403.26
DA00 - Dale Station-Common	26,153.31	-	-	-	-
SM50 - Smith CT's-Common	-	12,424.96	223,067.78	254,883.13	78,557.86
SP00 - Spurlock Station-Common	7,199,241.52	7,089,926.93	8,964,566.26	6,285,494.39	6,295,966.63
SP01 - Spurlock-Unit 1	5,821,595.84	5,495,824.37	6,537,277.46	7,396,304.65	6,653,977.43
SP02 - Spurlock-Unit 2	8,209,742.43	13,662,193.66	11,187,093.19	12,773,635.83	13,441,390.16
SP03 - Spurlock-Unit 3	8,395,940.75	10,093,234.19	9,496,747.34	9,792,131.57	6,865,222.17
SP04 - Spurlock-Unit 4	6,583,544.05	7,421,241.05	7,693,226.50	9,384,211.29	8,891,147.39
SP20 - Spurlock Scrubbers-Common	801,649.35	783,999.22	1,273,687.10	1,773,048.88	835,722.10
SP21 - Spurlock-Scrubber 1	1,436,908.55	1,452,661.39	1,497,906.64	1,816,661.08	1,703,644.17
SP22 - Spurlock-Scrubber 2	2,667,872.32	2,135,758.60	2,822,339.68	2,601,264.51	2,825,230.87
512000 - Maint. of Boiler Plant-Steam Gen	**46,819,820.79**	**53,758,286.91**	**57,601,659.98**	**56,898,527.66**	**50,449,925.59**
CP00 - Cooper Station-Common	685,388.23	1,368,588.18	600,758.23	990,961.29	573,066.54
CP01 - Cooper-Unit 1	399,644.05	210,174.19	78,056.54	994,994.96	146,989.78
CP02 - Cooper-Unit 2	88,688.83	1,065,064.84	829,707.11	365,663.87	376,451.32
DA00 - Dale Station-Common	1,899.36	-	-	-	-
SP00 - Spurlock Station-Common	317,421.42	135,904.09	311,557.05	494,809.42	351,126.69
SP01 - Spurlock-Unit 1	1,026,080.74	755,773.74	2,245,062.81	2,076,204.65	2,137,047.39
SP02 - Spurlock-Unit 2	1,759,898.49	7,418,912.38	1,780,251.26	3,081,445.77	1,787,261.30
SP03 - Spurlock-Unit 3	922,283.87	807,420.27	1,022,406.02	770,954.86	1,946,508.08
SP04 - Spurlock-Unit 4	694,404.39	548,874.80	600,865.55	2,134,925.67	1,090,508.34
513000 - Maint. of Elec Plant-Steam Gen	**5,895,709.38**	**12,310,712.49**	**7,468,664.57**	**10,909,960.49**	**8,408,959.44**
OC00 - Bluegrass Oldham Co-Common	45,988.09	76,380.05	112,345.00	158,507.12	179,742.98
SM50 - Smith CT's-Common	74,961.00	249,387.18	251,665.22	258,097.04	352,276.77
551000 - Maint. Supv/Engr-Oth Power Gen	**120,949.09**	**325,767.23**	**364,010.22**	**416,604.16**	**532,019.75**
LF01 - Green Valley LFGTE	-	7,883.40	-	3,546.51	224,847.70
LF02 - Laurel Ridge LFGTE	-	3,816.00	-	96,000.00	69,988.22
LF03 - Bavarian LFGTE	-	-	-	16,724.65	150,247.13
LF05 - Pendleton County LFGTE	5,492.75	-	-	-	-
OC00 - Bluegrass Oldham Co-Common	22,848.33	312,667.40	235,570.71	250,757.81	138,787.09
SM50 - Smith CT's-Common	711,495.24	696,949.87	666,455.48	461,289.11	521,002.31

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Account, Subaccount, Plant and Operating Unit

Production Maint by Account/Oper Unit	2016	2017	2018	2019	2020
552000 - Maint. of Structures-Oth Pwr Gen	739,836.32	1,021,316.67	902,026.19	828,318.08	1,104,872.45

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Account, Subaccount, Plant and Operating Unit

Production Maint by Account/Oper Unit	2016	2017	2018	2019	2020
DG01 - Cooper Diesel Generator	17,965.07	5,809.06	24,604.81	76,555.06	14,044.64
DG02 - Cagle's Diesel Generator	32,841.10	57,802.94	36,126.91	98,104.36	31,854.50
LF01 - Green Valley LFGTE	304,230.52	336,934.83	165,421.33	283,825.35	370,271.00
LF02 - Laurel Ridge LFGTE	450,773.87	250,243.63	274,670.96	731,626.71	266,247.83
LF03 - Bavarian LFGTE	614,174.62	648,351.96	560,993.62	827,482.73	714,746.10
LF04 - Hardin County LFGTE	333,090.74	46,891.48	88,202.33	44,298.79	213,938.04
LF05 - Pendleton County LFGTE	391,255.30	168,445.63	107,909.24	359,287.69	715,089.86
LF07 - Glasgow LFGTE	-	-	-	-	-
OC00 - Bluegrass Oldham Co-Common	365,837.70	340,858.48	274,165.26	430,497.09	1,077,563.37
OC01 - Bluegrass Oldham Co-1	36,175.10	156,647.99	217,562.89	202,496.27	187,235.64
OC02 - Bluegrass Oldham Co-2	28,925.58	432,592.03	228,369.13	365,360.36	383,748.02
OC03 - Bluegrass Oldham Co-3	-	-	-	737,510.35	135,343.88
SF01 - Solar Facility-Coop 1	-	-	16,061.70	38,725.32	31,556.57
SM50 - Smith CT's-Common	490,940.85	497,598.04	1,024,411.02	701,187.73	746,268.13
SM51 - Smith CT-Unit 1	2,671,697.19	105,048.75	21,743.38	120,790.61	100,568.20
SM52 - Smith CT-Unit 2	183,932.33	453,735.60	964,573.50	737,068.12	383,339.45
SM53 - Smith CT-Unit 3	135,560.67	124,080.07	4,733,919.68	490,756.97	100,936.39
SM54 - Smith CT-Unit 4	173,804.12	93,590.68	67,219.88	179,356.60	73,519.77
SM55 - Smith CT-Unit 5	140,541.52	209,084.52	146,872.82	514,052.36	58,569.99
SM56 - Smith CT-Unit 6	255,723.80	(110,696.78)	766,539.78	191,928.70	356,497.96
SM57 - Smith CT-Unit 7	171,824.23	1,380,599.39	143,846.30	499,976.55	92,865.00
SM59 - Smith CT-Unit 9	536,941.00	235,529.92	724,807.59	416,349.13	241,347.81
SM60 - Smith CT-Unit 10	463,448.58	389,983.94	621,769.94	718,551.56	920,274.91
553000 - Maint. of Gen&Elec Equip-Oth Gen	**7,799,683.89**	**5,823,132.16**	**11,209,792.07**	**8,765,788.41**	**7,215,827.06**
Grand Total, Expensed	**70,744,074.06**	**83,337,329.42**	**87,276,748.19**	**87,646,565.68**	**76,334,481.89**

Remove Regulatory Asset & (Amortization) Activity					
SP02 - Spurlock-Unit 2	-	-	-	1,587,411.68	(198,426.32)
SP04 - Spurlock-Unit 4	-	-	-	3,007,597.23	(375,949.47)
512000 - Maint. of Boiler Plant-Steam Gen	-	-	-	4,595,008.91	(574,375.79)
SP02 - Spurlock-Unit 2	-	-	-	561,450.00	(70,181.04)
SP04 - Spurlock-Unit 4	-	-	-	2,087,724.83	(260,965.91)
513000 - Maint. of Elec Plant-Steam Gen	-	-	-	2,649,174.83	(331,146.95)
Total, Regulatory Asset & (Amortization)	**-**	**-**	**-**	**7,244,183.74**	**(905,522.74)**
Total Maintenance Costs Incurred	**70,744,074.06**	**83,337,329.42**	**87,276,748.19**	**94,890,749.42**	**75,428,959.15**

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Account, Subaccount, Plant and Operating Unit (Excluding Leased Plant)

Production Maint by Account/Oper Unit	2016	2017	2018	2019	2020
CP00 - Cooper Station-Common	147,512.09	153,676.86	148,989.97	28,211.13	16,305.31
DA00 - Dale Station-Common	52,444.13	-	-	-	-
SP00 - Spurlock Station-Common	3,025,836.48	2,998,718.19	3,048,985.59	3,282,613.81	3,397,261.11
510000 - Maint. Supv/Engr-Steam Gen	**3,225,792.70**	**3,152,395.05**	**3,197,975.56**	**3,310,824.94**	**3,413,566.42**
CP00 - Cooper Station-Common	1,316,763.30	1,681,955.13	1,248,357.54	811,860.55	803,304.23
CP01 - Cooper-Unit 1	17,147.92	10,370.10	3,921.17	2,775.99	741.92
CP02 - Cooper-Unit 2	274.05	15,413.09	70,816.78	87,910.31	1,270.75
DA00 - Dale Station-Common	6,990.85	-	-	-	-
SP00 - Spurlock Station-Common	4,300,825.35	4,851,922.34	4,361,886.69	5,013,428.30	4,277,521.96
SP01 - Spurlock-Unit 1	367.34	9,115.41	279,204.73	328,840.23	305.90
SP02 - Spurlock-Unit 2	211.32	6,908.56	9,100.00	-	44,524.71
SP03 - Spurlock-Unit 3	346.01	44,775.76	2,041.90	24,573.33	1,012.42
SP04 - Spurlock-Unit 4	1,060.23	825.95	-	17,299.29	6,731.40
SP20 - Spurlock Scrubbers-Common	-	-	-	-	-
511000 - Maint. of Structures-Steam Gen	**5,643,986.37**	**6,621,286.34**	**5,975,328.81**	**6,286,688.00**	**5,135,413.29**
CP00 - Cooper Station-Common	2,787,419.99	2,470,505.05	3,419,440.03	2,234,539.89	1,385,899.62
CP01 - Cooper-Unit 1	1,216,778.16	955,980.33	1,165,294.01	1,106,371.48	575,564.66
CP02 - Cooper-Unit 2	1,146,796.79	977,303.16	2,553,762.31	799,992.83	220,199.27
CP22 - Cooper-Scrubber 2	526,177.73	1,207,234.00	767,251.68	679,988.13	677,403.26
DA00 - Dale Station-Common	26,153.31	-	-	-	-
SM50 - Smith CT's-Common	-	12,424.96	223,067.78	254,883.13	78,557.86
SP00 - Spurlock Station-Common	7,199,241.52	7,089,926.93	8,964,566.26	6,285,494.39	6,295,966.63
SP01 - Spurlock-Unit 1	5,821,595.84	5,495,824.37	6,537,277.46	7,396,304.65	6,653,977.43
SP02 - Spurlock-Unit 2	8,209,742.43	13,662,193.66	11,187,093.19	12,773,635.83	13,441,390.16
SP03 - Spurlock-Unit 3	8,395,940.75	10,093,234.19	9,496,747.34	9,792,131.57	6,865,222.17
SP04 - Spurlock-Unit 4	6,583,544.05	7,421,241.05	7,693,226.50	9,384,211.29	8,891,147.39
SP20 - Spurlock Scrubbers-Common	801,649.35	783,999.22	1,273,687.10	1,773,048.88	835,722.10
SP21 - Spurlock-Scrubber 1	1,436,908.55	1,452,661.39	1,497,906.64	1,816,661.08	1,703,644.17
SP22 - Spurlock-Scrubber 2	2,667,872.32	2,135,758.60	2,822,339.68	2,601,264.51	2,825,230.87
512000 - Maint. of Boiler Plant-Steam Gen	**46,819,820.79**	**53,758,286.91**	**57,601,659.98**	**56,898,527.66**	**50,449,925.59**
CP00 - Cooper Station-Common	685,388.23	1,368,588.18	600,758.23	990,961.29	573,066.54
CP01 - Cooper-Unit 1	399,644.05	210,174.19	78,056.54	994,994.96	146,989.78
CP02 - Cooper-Unit 2	88,688.83	1,065,064.84	829,707.11	365,663.87	376,451.32
DA00 - Dale Station-Common	1,899.36	-	-	-	-
SP00 - Spurlock Station-Common	317,421.42	135,904.09	311,557.05	494,809.42	351,126.69
SP01 - Spurlock-Unit 1	1,026,080.74	755,773.74	2,245,062.81	2,076,204.65	2,137,047.39
SP02 - Spurlock-Unit 2	1,759,898.49	7,418,912.38	1,780,251.26	3,081,445.77	1,787,261.30
SP03 - Spurlock-Unit 3	922,283.87	807,420.27	1,022,406.02	770,954.86	1,946,508.08
SP04 - Spurlock-Unit 4	694,404.39	548,874.80	600,865.55	2,134,925.67	1,090,508.34
513000 - Maint. of Elec Plant-Steam Gen	**5,895,709.38**	**12,310,712.49**	**7,468,664.57**	**10,909,960.49**	**8,408,959.44**
OC00 - Bluegrass Oldham Co-Common	45,988.09	76,380.05	112,345.00	158,507.12	179,742.98
SM50 - Smith CT's-Common	74,961.00	249,387.18	251,665.22	258,097.04	352,276.77
551000 - Maint. Supv/Engr-Oth Power Gen	**120,949.09**	**325,767.23**	**364,010.22**	**416,604.16**	**532,019.75**
LF01 - Green Valley LFGTE	-	7,883.40	-	3,546.51	224,847.70
LF02 - Laurel Ridge LFGTE	-	3,816.00	-	96,000.00	69,988.22
LF03 - Bavarian LFGTE	-	-	-	16,724.65	150,247.13
LF05 - Pendleton County LFGTE	5,492.75	-	-	-	-
OC00 - Bluegrass Oldham Co-Common	22,848.33	312,667.40	235,570.71	250,757.81	138,787.09
SM50 - Smith CT's-Common	711,495.24	696,949.87	666,455.48	461,289.11	521,002.31
552000 - Maint. of Structures-Oth Pwr Gen	**739,836.32**	**1,021,316.67**	**902,026.19**	**828,318.08**	**1,104,872.45**

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Production Maintenance Expense by Account, Subaccount, Plant and Operating Unit (Excluding Leased Plant)

Production Maint by Account/Oper Unit	2016	2017	2018	2019	2020
DG01 - Cooper Diesel Generator	17,965.07	5,809.06	24,604.81	76,555.06	14,044.64
DG02 - Cagle's Diesel Generator	32,841.10	57,802.94	36,126.91	98,104.36	31,854.50
LF01 - Green Valley LFGTE	304,230.52	336,934.83	165,421.33	283,825.35	370,271.00
LF02 - Laurel Ridge LFGTE	450,773.87	250,243.63	274,670.96	731,626.71	266,247.83
LF03 - Bavarian LFGTE	614,174.62	648,351.96	560,993.62	827,482.73	714,746.10
LF04 - Hardin County LFGTE	333,090.74	46,891.48	88,202.33	44,298.79	213,938.04
LF05 - Pendleton County LFGTE	391,255.30	168,445.63	107,909.24	359,287.69	715,089.86
LF07 - Glasgow LFGTE	-	-	-	-	-
OC00 - Bluegrass Oldham Co-Common	365,837.70	340,858.48	274,165.26	430,497.09	1,077,563.37
OC01 - Bluegrass Oldham Co-1	36,175.10	156,647.99	217,562.89	202,496.27	187,235.64
OC02 - Bluegrass Oldham Co-2	28,925.58	432,592.03	228,369.13	365,360.36	383,748.02
OC03 - Bluegrass Oldham Co-3	-	-	-	737,510.35	135,343.88
SF01 - Solar Facility-Coop 1	-	-	16,061.70	38,725.32	31,556.57
SM50 - Smith CT's-Common	490,940.85	497,598.04	1,024,411.02	701,187.73	746,268.13
SM51 - Smith CT-Unit 1	2,671,697.19	105,048.75	21,743.38	120,790.61	100,568.20
SM52 - Smith CT-Unit 2	183,932.33	453,735.60	964,573.50	737,068.12	383,339.45
SM53 - Smith CT-Unit 3	135,560.67	124,080.07	4,733,919.68	490,756.97	100,936.39
SM54 - Smith CT-Unit 4	173,804.12	93,590.68	67,219.88	179,356.60	73,519.77
SM55 - Smith CT-Unit 5	140,541.52	209,084.52	146,872.82	514,052.36	58,569.99
SM56 - Smith CT-Unit 6	255,723.80	(110,696.78)	766,539.78	191,928.70	356,497.96
SM57 - Smith CT-Unit 7	171,824.23	1,380,599.39	143,846.30	499,976.55	92,865.00
SM59 - Smith CT-Unit 9	536,941.00	235,529.92	724,807.59	416,349.13	241,347.81
SM60 - Smith CT-Unit 10	463,448.58	389,983.94	621,769.94	718,551.56	920,274.91
553000 - Maint. of Gen&Elec Equip-Oth Gen	**7,799,683.89**	**5,823,132.16**	**11,209,792.07**	**8,765,788.41**	**7,215,827.06**
Grand Total, Expensed	**70,245,778.54**	**83,012,896.85**	**86,719,457.40**	**87,416,711.74**	**76,260,584.00**

Remove Regulatory Asset & (Amortization) Activity					
SP02 - Spurlock-Unit 2	-	-	-	1,587,411.68	(198,426.32)
SP04 - Spurlock-Unit 4	-	-	-	3,007,597.23	(375,949.47)
512000 - Maint. of Boiler Plant-Steam Gen	-	-	-	4,595,008.91	(574,375.79)
SP02 - Spurlock-Unit 2	-	-	-	561,450.00	(70,181.04)
SP04 - Spurlock-Unit 4	-	-	-	2,087,724.83	(260,965.91)
513000 - Maint. of Elec Plant-Steam Gen	-	-	-	2,649,174.83	(331,146.95)
Total, Regulatory Asset & (Amortization)	-	-	-	**7,244,183.74**	**(905,522.74)**
Total Maintenance Costs Incurred	**70,245,778.54**	**83,012,896.85**	**86,719,457.40**	**94,660,895.48**	**75,355,061.26**

EXHIBIT___(LK-11)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 7
RESPONSIBLE PERSON: **Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 7. Describe how the Company calculated depreciation expense on production plant for accounting and ratemaking purposes prior to the 2006 rate proceeding. For example, for accounting purposes and in one or more rate proceedings prior to the 2006 proceeding, indicate whether the Company calculated depreciation expense on production plant as the net book value divided by the remaining months of service based on the probable retirement date. If so, identify the last rate proceeding that it relied on that calculation methodology and indicate when it changed to the present calculation of multiplying the gross plant times the approved depreciation rates for accounting and ratemaking purposes.

Response 7. It is important to note that EKPC is only now, as part of this rate case proceeding, proposing to use a calculation whereby the original cost of the assets will be multiplied by the approved depreciation rates to determine depreciation expense for accounting and ratemaking purposes. This methodology, as fully described in the direct testimony of Mr. Spanos, incorporates both service lives and net salvage into the depreciation rates. From 2006 through current, EKPC has used the probable retirement dates of production plant to determine depreciation. In a previous EKPC rate case (Case No. 2006-00472), Exhibit F, Schedule 8, Page 1 explains that EKPC used the probable retirement dates reflected in the December 31, 2005 depreciation study approved in Case No. 2006-00236 for production plant.

EKPC questions the relevance of the historical aspect of this request given depreciation rates and methodologies used prior to 2006 have no bearing on this rate case proceeding. However, EKPC offers the following results of its research: Prior to 2006, depreciation studies and related calculations were only addressed twice in formal proceedings: 1) in Environmental Surcharges Case No. 2004-00321 whereby EKPC ultimately agreed as part of a settlement, to conduct a full depreciation study in two years, which was completed and filed in Case No. 2006-00236, as mentioned above, and 2) in Rate Case No. 1994-00336 whereby EKPC was required to conduct a full depreciation study within two years. The results of that study were filed with the Commission in 1998 and EKPC continued to use probable retirement dates of production plant as the methodology in determining depreciation.

EXHIBIT___(LK-12)

East Kentucky Power Cooperative, Inc.

Notes to Financial Statements (continued)

1. Summary of Significant Accounting Policies (continued)

Electric Plant in Service

Electric plant is stated at original cost, which is the cost of the plant when first dedicated to public service by the initial owner, plus the cost of all subsequent additions. The cost of assets constructed by the Cooperative includes material, labor, contractor and overhead costs.

The cost of maintenance and repairs, including renewals of minor items of property, is charged to operating expense. The cost of replacement of depreciable property units, as distinguished from minor items, is charged to electric plant. The cost of units replaced or retired, including cost of removal, net of any salvage value, is charged to accumulated depreciation.

Depreciation and Amortization

Depreciation for the generating plants and transmission facilities is provided on the basis of estimated useful lives at straight-line composite rates. Rates applied to electric plant in service for both 2019 and 2018 are:

Transmission and distribution plant	0.71%–3.42%
General plant	2.0%–20.00%

The production plant assets are depreciated on a straight-line basis from the date of acquisition to the end of life of the respective plant, which ranged from 2030 to 2051 in 2019 and 2018.

Depreciation and amortization expense was $121.7 million and $119.7 million for 2019 and 2018, respectively. Depreciation and amortization expense includes amortization expense of $12.2 million in 2019 and $12.6 million in 2018 related to plant abandonments granted regulatory asset treatment (Note 5).

The Cooperative received PSC approval to charge depreciation associated with asset retirement obligations to regulatory assets. These regulatory assets are charged to depreciation expense as recovery occurs. Depreciation charged to regulatory assets was $5.8 million and $6.3 million in 2019 and 2018, respectively.

EXHIBIT___(LK-13)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 29
RESPONSIBLE PERSON: **Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 29. Refer to Exhibit JJS-1, pages 69 and 146 of 245, which report data related to retirements for plant account 314 *Turbogenerator Units*. Page 69 lists retirements during age interval 9.5 years as $73,776,163. Page 146 lists retirements during 2019 of $73,792,664.

Request 29a. Provide a description and the amount of each retirement recorded on the books during 2019 for plant account 314 for each generating unit.

Response 29a. A summary of Account 314000 retirements by generating unit is provided on Page 3 of this response. The majority of these retirements were related to the scheduled Spurlock Unit 4 turbine overhaul. It should be noted that compatible Smith Unit 1 Regulatory Asset parts valued at approximately $20.6 million were used in the turbine overhaul project, thereby negating the need for additional cash outlay and also reducing the balance of the regulatory asset to be recovered in this rate case proceeding.

Request 29b. Provide copies of the journal entries made to record the retirements of plant in plant account 314 during 2019 for each generating unit.

Response 29b. Please see pages 4 through 7 of this response for copies of the retirement journal entries for Account 314000 that occurred in 2019.

Request 29c. Provide the plant in service and accumulated depreciation balances at the end of each month during 2019 associated with plant account 314 for each generating unit.

Response 29c. Please see page 8 of this response and corresponding *AG Nucor DR1 Response 29c.xlsx* for a schedule of Account 314000 plant in-service and accumulated depreciation by generating unit for each month in 2019. It should be noted that the December 2019 balance also includes balances in Account 106000, Completed Construction not Classified, that pertain to account 314000.

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Account 314000 Retirements
Test Year 2019

Journal ID	Account	Unit	Amount	Asset ID	Asset Descripttion
RET0046307	314000	SP02	$ 24,699.15	12943	Lube Oil Storage Tank
RET0049268	314000	SP04	$ 23,118,165.58	142704	Tubine, LP Rotor
RET0049269	314000	SP04	$ 23,958,826.20	142647	Generator Stator
RET0049269	314000	SP04	$ 3,362,642.27	142685	Stop Valve, Combined Reheat
RET0049269	314000	SP04	$ 840,660.57	142686	Stop Valve, Main Stream
RET0049269	314000	SP04	$ 1,471,156.00	142695	Turbine, HP Diaphragms
RET0049269	314000	SP04	$ 12,609,908.53	142699	Turbine, HP/IP Rotor and Assembly
RET0049269	314000	SP04	$ 8,406,605.68	142700	Turbine, IP Diaphragms
Total			$ 73,792,663.98		

East Kentucky Power Cooperative, Inc.
Report ID: GLX7501

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

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Run Date 2/14/19
Run Time: 2:22:53 PM

Unit	EKPC	**Ledger Group:**	ACTUALS	**Foreign Currency:**	USD
Journal ID:	RET0046307	**Source:**	AM	**Rate Type:**	
Journal Date:	1/31/19	**Reversal:**	None	**Effective Date:**	1/31/19
Description:	Asset Retirements	**Reversal Date:**		**Exchange Rate:**	1.00000000
				Ledger:	ACTUALS

Line #	Account	Oper Unit	Dept	Budget Cd	PC Bus Unit	Project	Activity	Source Type	Category	Sub Cat	Base Amount	Statistic Amt
1	108142	----	----	----	----	----	----	----	----	----	20,261.85 USD	
	Description: Retire assets from plant											
2	108800	----	----	----	EKPC	0S363	995	74	92405	00000	-40,441.33 USD	
	Description: Retire assets from plant											
3	108914	----	----	----	----	----	----	----	----	----	44,878.63 USD	
	Description: Retire assets from plant											
4	314000	SP02	----	----	----	----	----	----	----	----	-24,699.15 USD	
	Description: Retire assets from plant											

Business Unit	Total Lines	Total Base Debits	Total Base Credits
EKPC	4	65,140.48	65,140.48

Prepared by: Lm 2/14/19

Supervisor Review: DL 2/15/19

Controller Review: ______________

Posted by: ______________

East Kentucky Power Cooperative, Inc.
Report ID: GLX7501

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

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Run Date: 1/21/20
Run Time: 12:05:37 PM

Unit	EKPC	**Ledger Group:**	ACTUALS	**Foreign Currency:**	USD
Journal ID:	RET0049268	**Source:**	AM	**Rate Type:**	
Journal Date:	12/31/19	**Reversal:**	None	**Effective Date:**	12/31/19
Description:	Asset Retirements	**Reversal Date:**		**Exchange Rate:**	1 00000000
				Ledger:	ACTUALS

Line #	Account	Oper Unit	Dept	Budget Code	PC Bus Unit	Project	Activity	Source Type	Category	Sub Cat	Base Amount	Statistic Amt
1	108144	—	—	—	—	—	—	—	—	—	5,839,371.01 USD	
	Description: Retire assets from plant											
2	108800	—	—	—	EKPC	0S480	995	74	92405	00000	-274,570.74 USD	
	Description: Retire assets from plant											
3	108915	—	—	—	—	—	—	—	—	—	17,553,365.31 USD	
	Description: Retire assets from plant											
4	314000	SP04	—	—	—	—	—	—	—	—	-23,118,165.58 USD	
	Description: Retire assets from plant											

Business Unit	Total Lines	Total Base Debits	Total Base Credits
EKPC	4	23,392,736 32	23,392,736.32

Prepared by: [signature] 1/21/2020

Supervisor Review: [signature] 1/21/2020

Controller Review: [signature]

Posted by:

East Kentucky Power Cooperative, Inc.
Report ID: GLX7501

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

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Run Date: 1/21/20
Run Time: 12:08:23 PM

Unit	EKPC	**Ledger Group:**	ACTUALS	**Foreign Currency:**	USD
Journal ID:	RET0049269	**Source:**	AM	**Rate Type:**	
Journal Date:	12/31/19	**Reversal:**	None	**Effective Date:**	12/31/19
Description:	Asset Retirements	**Reversal Date:**		**Exchange Rate:**	1.00000000
				Ledger:	ACTUALS

Line #	Account	Oper Unit	Dept	Budget Code	PC Bus Unit	Project	Activity	Source Type	Category	Sub Cat	Base Amount	Statistic Amt
1	108144	—	—	—	—	—	—	—	—	—	12,793,531.13 USD	
	Description: Retire assets from plant											
2	108800	—	—	—	EKPC	0S480	995	74	92405	00000	-434,320.99 USD	
	Description: Retire assets from plant											
3	108915	—	—	—	—	—	—	—	—	—	38,290,589.11 USD	
	Description: Retire assets from plant											
4	314000	SP04	—	—	—	—	—	—	—	—	-50,649,799.25 USD	
	Description: Retire assets from plant											

Business Unit	Total Lines	Total Base Debits	Total Base Credits
EKPC	4	51,084,120.24	51,084,120.24

Prepared by: Am 1/21/2020
Supervisor Review: Dc 1/21/2020
Controller Review: [illegible]
Posted by:

East Kentucky Power Cooperative, Inc.
Report ID: GLX7501

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

Run Date: 1/23/20
Run Time: 12:02:59 PM

Unit	EKPC	**Ledger Group:**	ACTUALS	**Foreign Currency:**	USD
Journal ID:	0000049302	**Source:**	LM	**Rate Type:**	CRRNT
Journal Date:	12/31/19	**Reversal:**	None	**Effective Date:**	12/31/19
Description:	Correct project on RET0049268 and RET0049269	**Reversal Date:**		**Exchange Rate:**	1.00000000
				Ledger:	ACTUALS

Line #	Account	Oper Unit	Dept	Budget Code	PC Bus Unit	Project	Activity	Source Type	Category	Sub Cat	Base Amount	Statistic Amt
1	108800	—	—	—	EKPC	0S480	995	74	92405	00000	708,891.73 USD	
	Description: Corr Proj fr 0S480 to 0S510											
2	108800	—	—	—	EKPC	0S510	995	74	92405	00000	-708,891.73 USD	
	Description: Corr Proj fr 0S480 to 0S510											

Business Unit	Total Lines	Total Base Debits	Total Base Credits
EKPC	2	708,891.73	708,891.73

Prepared by: Bm 1/23/2020

Supervisor Review: DC 1/23/2020

Controller Review:

Posted by: HV 1/24/2020

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
314000 Plant in Service, Accumulated Depreciation, and Net Book Value by Generating Unit

Spurlock Unit 1	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
Plant In Service Balance	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29	$ 33,699,815.29
Accumulated Depreciation	$ 26,341,874.74	$ 26,370,504.87	$ 26,399,135.00	$ 26,427,765.13	$ 26,456,395.26	$ 26,485,025.39	$ 26,513,655.52	$ 26,542,285.65	$ 26,570,915.78	$ 26,599,545.91	$ 26,628,176.04	$ 26,656,805.96
Net Book Value	$ 7,357,940.55	$ 7,329,310.42	$ 7,300,680.29	$ 7,272,050.16	$ 7,243,420.03	$ 7,214,789.90	$ 7,186,159.77	$ 7,157,529.64	$ 7,128,899.51	$ 7,100,269.38	$ 7,071,639.25	$ 7,043,009.33
Spurlock Unit 2												
Plant In Service Balance	$ 51,449,697.48	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60	$ 60,137,136.60
Accumulated Depreciation	$ 36,590,389.35	$ 37,085,003.63	$ 37,167,332.64	$ 37,249,661.65	$ 37,331,990.66	$ 37,414,319.67	$ 37,496,648.68	$ 37,578,977.69	$ 37,661,306.70	$ 37,743,635.71	$ 37,825,964.72	$ 37,908,294.20
Net Book Value	$ 14,859,308.13	$ 23,052,132.97	$ 22,969,803.96	$ 22,887,474.95	$ 22,805,145.94	$ 22,722,816.93	$ 22,640,487.92	$ 22,558,158.91	$ 22,475,829.90	$ 22,393,500.89	$ 22,311,171.88	$ 22,228,842.40
Spurlock Unit 3												
Plant In Service Balance	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55	$ 80,408,959.55
Accumulated Depreciation	$ 27,365,008.14	$ 27,532,339.41	$ 27,699,670.68	$ 27,867,001.95	$ 28,034,333.22	$ 28,201,664.49	$ 28,368,995.76	$ 28,536,327.03	$ 28,703,658.30	$ 28,870,989.57	$ 29,038,320.84	$ 29,205,649.91
Net Book Value	$ 53,043,951.41	$ 52,876,620.14	$ 52,709,288.87	$ 52,541,957.60	$ 52,374,626.33	$ 52,207,295.06	$ 52,039,963.79	$ 51,872,632.52	$ 51,705,301.25	$ 51,537,969.98	$ 51,370,638.71	$ 51,203,309.64
Spurlock Unit 4												
Plant In Service Balance	$ 129,736,588.09	$ 129,736,588.09	$ 129,736,588.09	$ 129,736,588.09	$ 129,736,588.09	$ 129,938,368.22	$ 129,938,368.22	$ 129,938,368.22	$ 129,938,368.22	$ 129,938,368.22	$ 129,938,368.22	$ 80,239,064.25
Accumulated Depreciation	$ 31,619,475.98	$ 31,888,719.93	$ 32,157,963.88	$ 32,427,207.83	$ 32,696,451.78	$ 32,975,811.35	$ 33,245,587.70	$ 33,515,364.05	$ 33,785,140.40	$ 34,054,916.75	$ 34,324,693.10	$ 15,281,027.96
Net Book Value	$ 98,117,112.11	$ 97,847,868.16	$ 97,578,624.21	$ 97,309,380.26	$ 97,040,136.31	$ 96,962,556.87	$ 96,692,780.52	$ 96,423,004.17	$ 96,153,227.82	$ 95,883,451.47	$ 95,613,675.12	$ 64,958,036.29
Cooper												
Plant In Service Balance	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,875,381.59	$ 23,714,956.78
Accumulated Depreciation	$ 18,088,649.69	$ 18,130,888.67	$ 18,173,127.65	$ 18,215,366.63	$ 18,257,605.61	$ 18,299,844.59	$ 18,342,083.57	$ 18,384,322.55	$ 18,426,561.53	$ 18,468,800.51	$ 18,511,039.49	$ 18,507,702.47
Net Book Value	$ 5,786,731.90	$ 5,744,492.92	$ 5,702,253.94	$ 5,660,014.96	$ 5,617,775.98	$ 5,575,537.00	$ 5,533,298.02	$ 5,491,059.04	$ 5,448,820.06	$ 5,406,581.08	$ 5,364,342.10	$ 5,207,254.31
Totals												
Plant In Service Balance	$ 319,170,442.00	$ 327,857,881.12	$ 327,857,881.12	$ 327,857,881.12	$ 327,857,881.12	$ 328,059,661.25	$ 328,059,661.25	$ 328,059,661.25	$ 328,059,661.25	$ 328,059,661.25	$ 328,059,661.25	$ 278,199,932.47
Accumulated Depreciation	$ 140,005,397.90	$ 141,007,456.51	$ 141,597,229.85	$ 142,187,003.19	$ 142,776,776.53	$ 143,376,665.49	$ 143,966,971.23	$ 144,557,276.97	$ 145,147,582.71	$ 145,737,888.45	$ 146,328,194.19	$ 127,559,480.50
Net Book Value	$ 179,165,044.10	$ 186,850,424.61	$ 186,260,651.27	$ 185,670,877.93	$ 185,081,104.59	$ 184,682,995.76	$ 184,092,690.02	$ 183,502,384.28	$ 182,912,078.54	$ 182,321,772.80	$ 181,731,467.06	$ 150,640,451.97

EXHIBIT___(LK-14)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 16
RESPONSIBLE PERSON: Craig A. Johnson / Michelle K. Carpenter
COMPANY: East Kentucky Power Cooperative, Inc.

Request 16. Refer to the response to AG-Nucor 1-29.

Request 16a. Provide the dates of the Spurlock Unit 4 turbine overhaul.

Response 16a. The dates of the Spurlock Unit 4 turbine overhaul were from 4/7/2019 to 6/7/2019.

Request 16b. Describe the scope of the Spurlock Unit 4 turbine overhaul and contrast it to the scope of each prior and subsequent turbine overhaul of Spurlock Units 1, 2, 3, and 4.

Response 16b. A typical scope of work for performing a major turbine overhaul on the Spurlock units is provided on pages 6 through 9 of this response.

Request 16c. Indicate whether the scope of the Spurlock Unit 4 turbine overhaul was unusual in any respect or was undertaken in the normal course of business. If unusual, then describe why it was unusual and provide a copy of any studies, assessments, and/or reports that address the root cause of an event that would have caused the retirement of the equipment. If normal, then describe how the Company made that assessment.

Response 16c. EKPC's current standard practice is to complete major turbine overhauls on a 10 year cycle. Spurlock unit 4's 2019 major overhaul was not unusual as it relates to the general scope of all EKPC steam turbine overhauls. Specifics of a standard overhaul scope, not including discovery are described in response to 16b. What was different was in the planned approach to use the purchased, but never used, Smith unit turbine and generator rotors. EKPC worked diligently to sell the Smith unit assets on the open market but no buyers were found. The Smith assets were found to be interchangeable with EKPC's Gilbert 3 and Spurlock 4. Instead of selling them as scrap, they had tremendous value to EKPC and our member owners. By utilizing them in EKPC's Core Exchange Program ("CEP") the overall cost of the Spurlock 4's major turbine overhaul could be better controlled. When performing a traditional major turbine overhaul on Spurlock Units 1 or 2, neither of which have a spare core, all work is completed as emergent and within the outage window at premium expense to the members. This CEP approach allowed for any repairs to the rotating components to be completed after the outage, at straight-time rates, and made ready for the next outage. A second and maybe larger benefit is that it helps control outage duration creep. It has happened in the past that the discovery work and OEM ability to turn around repairs resulted in longer outages. Longer outages mean additional replacement power could be required and could cost more than the specific units dispatch costs. The CEP strategy takes the risk of issues with those components out of the equation, which is a benefit to EKPC's members. Spurlock 3 is scheduled for a major turbine overhaul in 2025. The CEP method will be used to develop the scope for that outage. EKPC was still actively trying to sell the Smith assets during the first major turbine overhaul for Spurlock 3 in 2015.

Request 16d. Provide a history of each Spurlock Unit 1, 2, 3, and 4 turbine overhaul with the following information: i) the dates of each, ii) scope of each, iii) maintenance expense incurred, iv) capital cost incurred, and v) plant retirements recorded.

Response 16d. The dates for previous Spurlock unit turbine overhauls, for which EKPC has good data, are as follows;

i) Spurlock 1: July 1, 2004 to October 27, 2004 (Forced outage; extended for generator work); March 29, 2013 to May 29, 2013;

Spurlock 2: March 29, 2008 to June 7, 2008; September 9, 2017 to December 3, 2017

Spurlock 3: March 1, 2015 to April 26, 2015

Spurlock 4: April 7, 2019 to June 7, 2019

ii) The scope of each outage is consistent with what is described in the response to 16b

iii) Spurlock 1: 2004- $2,408,934
2013- $4,993,150
Spurlock 2: 2008- $8,528,709
2017- $6,301,950
Spurlock 3: 2015- $4,088,092
Spurlock 4: 2019- $2,087,725

iv) Spurlock 4: 2019-$24,750,129

v) Spurlock 4: Rotors & Field

Request 16e. Confirm that the net book value of the Spurlock Unit 4 retirements is reflected as an asset amount in (reduction to) the accumulated depreciation reserve and that it is included in the Spurlock Unit 4 net plant in the depreciation study in this proceeding.

Response 16e. The net book value of the assets retired in conjunction with the Spurlock Unit 4 turbine overhaul, along with the associated cost of removal, was debited to accumulated depreciation on EKPC's books at December 31, 2019. EKPC confirms these records were the basis for the depreciation study completed by Gannett Fleming Valuation and Rate Consultants, LLC.

Request 16f. Provide the actual accumulated depreciation related to the Spurlock Unit 4 retirements December 2019 and the net book value reflected as a reduction to the accumulated depreciation after the retirements were recorded.

Response 16f. Please refer to the information listed below that shows the original cost and accumulated depreciation to arrive at the net book value of assets retired in December 2019 in conjunction with the Spurlock Unit 4 turbine overhaul project. As indicated in Response 16e, the net book value of the retired assets and the associated removal costs were debited to accumulated depreciation at December 31, 2019.

	Amount
Original Cost of Assets Retired	$73,767,965
Accumulated Depreciation	(18,632,902)
Net Book Value	55,135,063
Plus: Cost of Removal	708,892
Debit to Accumulated Depreciation at Retirement	$55,843,955

Standard Steam Turbine Major Base Scope

Steam Turbines:

Contractor to provide Project management/technical direction for each outage. East Kentucky Power Cooperative (EKPC) will provide technicians to disassemble/reassemble the equipment. Contractor will provide the services of specialized technicians on an as needed basis.

Note: Basic scope is completed in all cases. Scope may be modified as result pre-outage planning and review of prior reports. Scope changes related to discoveries in outage are evaluated and corrective measures determined at that time.

Pre-outage:

- Review unit operating history and prior outage reports
- Conduct Pre-Outage Planning
- Develop a list of General Electric (GE) Technical Information Letters (TILs) and discuss with EKPC
- Develop an outage task list
- Develop laydown plan
- Develop Foreign Material Exclusion (FME) plan
- Develop spare parts list
- Develop a pre-outage schedule in Primavera P6 (P6)

General:

- Remove / reinstall lagging
- Remove / reinstall valve insulation
- Have scaffolding and plan ready when needed.
- Determine needed Lock Out Tag Out (LOTO) activities

High Pressure (HP) Intermediate Pressure (IP) Section:

- Disassembly of the HP/IP Section
- Chart opening steam path clearances.

- Send all in service diaphragms to desired vendor to Clean & Inspection of all diaphragms **
    - o Replace packing & spill strips as required, remove packing prior to shipment of diaphragms to site.
- Send out Nozzle (N)1, N2, N3 packing heads for blast cleaning and Non Destructive Examination (NDE).
    - o Replace packing & spill strips as required, remove packing prior to shipment of diaphragms to site.
- Send out HP/IP rotor **
    - o Blast clean
    - o Magnetic particle inspection
    - o Mechanical inspection including run out
    - o Bore plug removal
    - o Life Extension Services Bore sonic inspection
    - o Bore plug supply & install
    - o Final Balance check
- Send out Nozzle Box for inspections including 100% Area checks.
- Remove HP Inner Shell and ship to desired vendor for cleaning, inspection, and repair.
    - o Blast clean, visual and magnetic particle inspection.
    - o Inspect snouts
    - o Ultrasonic Testing (UT) of studs only. Confirm that a UT Inspection of the stubs and a wobble check with studs installed is adequate for continued operation.
    - o Wobble check of studs.
- Clean & inspect all remaining HP section parts onsite
- Clean & inspect all HP bearings
- Receive all HP section components after inspect/repairs
- Install diaphragms, correct side slip, axial crush pin clearance
- Perform tops off tops on alignment.
- Re-install packing
- Install HP rotor
- Chart Clearances
- Assemble Inner Shells & Outer Shells
- Assemble Standards & complete final unit Assembly

<u>Low Pressure (LP) Section:</u>

- Disassembly of Low Pressure Section
- Chart opening steam path clearances.

- Send all in service diaphragms to desired vendor for Clean & Inspection of all diaphragms. **
  - o Replace packing & spill strips as required, remove packing prior to shipment of diaphragms to site.
- Send out LP rotor **
  - o Blast clean
  - o Magnetic particle inspection
  - o Mechanical inspection including run out
  - o Bore plug removal
  - o Life Extension Services Bore sonic inspection
  - o Bore plug supply & install
  - o Final Balance check
- Clean & inspect all remaining LP components onsite
- Clean & inspect all LP bearings
- Receive all LP section components after inspect/repairs
- Install diaphragms, correct side slip, axial crush pin clearance
- Perform alignment program.
- Re-install packing
- Install LP rotor
- Chart closing clearance
- Assemble upper half components.
- Assemble Standards & complete final unit Assembly

<u>Valves:</u>

- Disassemble all valves from the valve bodies. Clean and inspect valve studs and seats at site, Visual, Liquid Penetrant Test (PT), and UT inspections were applicable.
- Main Stop valve: Disassemble & Inspection - Onsite
- Control valves: send to desired vendor for disassembly, clean inspection, reassembly
- Combined Reheat Valves (CRV): Send both CRVs to desired vendor for disassembly, clean, inspection, and reassembly.
- Blowdown Valve: Disassemble, Inspection, reassemble – Onsite
- Perform contact checks, maximum lapping

Boiler Feed Pump Turbines, Steam (if applicable)

- Disassembly of both Boiler Feed Pump Turbines
- Chart opening steam path clearances

- Remove all steam path components
- Disassemble packing from diaphragms
- Blast clean and NDE all steam path components onsite
- Perform all steam path mechanical inspections onsite
- Disassemble all stop and control valves from valve bodies. Clean and inspect valve studs and seats at site, Visual, PT, and UT inspections were applicable
- Perform bearing inspections
- Install diaphragms, correct side slip, axial crush pin clearance & align according to agreed upon alignment program.
- Re-install packing
- Install rotor
- Chart Clearances
- Assemble Shell
- Install valves and perform contact checks
- Assemble Standards and complete final unit assembly

** *With Spurlock 3 & 4 now having spare HP/IP & LP rotors and full diaphragm sets, off site work on these key components during the outage window is not required. This complies with our new Core Exchange Program (CEP) adopted for these units.*

EXHIBIT___(LK-15)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC FOR APPROVAL OF A DEPRECIATION STUDY	)))	CASE NO. 2006-00236

APPLICATION

1. Applicant, East Kentucky Power Cooperative, Inc., hereinafter referred to as "EKPC", Post Office Box 707, 4775 Lexington Road, Winchester, Kentucky 40392-0707, files this Application for approval of a new depreciation study relating to its service facilities.

2. This Application is made pursuant to KRS §278.040 and related statutes, and 807 KAR 5:001 Section 8, and related sections.

3. A copy of Applicant's restated Articles of Incorporation and all amendments thereto were filed with the Public Service Commission (the "Commission") in PSC Case No. 90-197, the Application of EKPC for a Certificate of Public Convenience and Necessity to Construct Certain Steam Service Facilities in Mason County, Kentucky.

4. EKPC, as a part of the Settlement Agreement reached in PSC Case No. 2004-00321 with the Office of the Attorney General and Gallatin Steel Company, agreed to have a Depreciation Study performed on all of its assets, and to apply for approval of such study by the Commission and the Rural Utilities Service. EKPC files this Application in compliance with its agreement to submit the Depreciation Study to the Commission within 60 days of its completion.

5. Attached as Exhibit I to this Application is the Direct Testimony of Ann F. Wood on behalf of EKPC, which discusses the preparation of EKPC's new Depreciation Study, and

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF EAST KENTUCKY POWER COOPERATIVE, INC., FOR APPROVAL OF A DEPRECIATION STUDY	**) CASE NO.**

DIRECT TESTIMONY OF ANN F. WOOD
ON BEHALF OF
EAST KENTUCKY POWER COOPERATIVE, INC.

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

A. My name is Ann F. Wood, and my business address is 4775 Lexington Road, Winchester, Kentucky 40391. I am the Manager of Accounting and Materials Management for East Kentucky Power Cooperative, Inc., ("EKPC").

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

A. I received a B.S. Degree in Accounting from Georgetown College in 1987. After graduation I accepted an audit position with Coopers & Lybrand in the Lexington office. My responsibilities ranged from performing detailed audit testing to managing audits. In October 1995, I started working for Lexmark International, Inc. as an analyst. In May 1997, I joined EKPC as Manager of Internal Auditing. In February 2002, I became Manager of Accounting and Materials Management at EKPC. I am a certified public accountant in Kentucky.

Q. **Please provide a brief description of your duties at EKPC.**

A. As Manager of Accounting and Materials Management, I am responsible for all aspects of general accounting, payroll, plant accounting, purchasing, and the Winchester warehouse. I report directly to the Vice President of Finance.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring one exhibit referenced as Wood Exhibit 1.

Q. What is the purpose of your testimony?

A. In accordance with the Kentucky Public Service Commission (the "Commission") Order Approving the Application for Approval of an Environmental Compliance Plan and Implementation of an Environmental Surcharge in Case No. 2004-00321, EKPC engaged Gannett Fleming, Inc. ("Gannett Fleming") to perform a depreciation study for all assets. This depreciation study included an assessment of all EKPC assets in service at December 31, 2005. The purpose of my testimony is to sponsor the results of, and identify the major recommendations contained in, the depreciation study, in support of EKPC's request for approval of the study, and for authority to apply the asset life extensions recommended by this study, for book and future ratemaking purposes, beginning January 1, 2006.

Q. When did EKPC begin the depreciation study process?

A. In May 2005, EKPC sent a request for proposals for the study to four firms, and received proposals from two of the firms solicited. In September 2005, EKPC selected Gannett Fleming to perform the depreciation study.

Q. When was the depreciation study completed?

A. Gannett Fleming issued the final report, attached as Wood Exhibit 1, on May 26, 2006.

Q. What are the major findings in the depreciation study?

A. The results of the study are reflected in Section III of Wood Exhibit 1. The major change is to extend the retirement dates of production plant. Below is a summary of Gannett Fleming's recommendations regarding production plant.

	Current Depreciation End Date	Proposed Depreciation End Date	Additional Life (Years)
Dale	Fully Depreciated	2019	13
Cooper	2022	2030	8
Spurlock Common	2027	2045	18
Spurlock 1	2027	2040	13
Spurlock 2	2027	2042	15
Gilbert	2037	2045	8
CT 1,2,3	2023	2035	12
CT 4,5	2027	2041	14
CT 6,7	2029	2045	16
Landfills	2018	2038	20

Q. What information did the consultant review in making the recommendation to extend the useful life of those facilities?

A. Based upon the "Description of Statistical Support" in III-2 of Wood Exhibit 1, Gannett Fleming concluded that "the service life and salvage estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies."

Q. When do you plan to implement the results of this study for book purposes?

A. Upon approval by the Commission and the Rural Utilities Service ("RUS"), EKPC plans to apply the rates outlined in the study beginning January 1, 2006, since the study established its recommended changes in the service lives of the assets as of 12/31/05.

Q. What impact does this study have for future ratemaking purposes?

EXHIBIT___(LK-16)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 23
RESPONSIBLE PERSON: **John J. Spanos**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 23. Refer to Exhibit JJS-1 and the table of depreciable life spans and estimated retirement dates for each of the production plants. Explain all reasons why the depreciable life spans for Smith Unit 1, Unit 2, and Unit 3 reflect only 35-year life spans while Smith Units 4-10 all reflect life spans of 40 years.

Response 23. Similar to the process for steam facilities, life spans are determined based on various factors, which include technology of the facility, management plans, outlook for the facility, type of construction, condition of the facility, regulations and estimates of similar facilities within the electric industry. For combustion turbines, life spans have generally been expected to be in the 30-40-year range; however, these units are generally peaking. Therefore, based on EKPC plans for all the Smith units, the efficiencies of the units and how each is utilized in the overall generation fleet, it is expected that Smith Units 1, 2 & 3 will be retired/rehabilitated after 35 years while the others will have a 40-year life span. Demand of these peaking units is also a consideration for these units.

EXHIBIT___(LK-17)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 14
RESPONSIBLE PERSON: **Craig A. Johnson / John J. Spanos**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 14. Refer to the response to AG-Nucor 1-23.

Request 14a. Provide a chart comparing the technical characteristics and operating characteristics for each of the Smith CTs and each of the Bluegrass Oldham CTs showing all similarities and dissimilarities.

Response 14a. Please refer to the chart on page 4 of this response.

Request 14b. The response indicates that the proposed 35-year life spans for Smith Units 1-3 and 40-year life spans for Smith Units 4-10 are based on "EKPC plans for all the Smith units, the efficiencies of the units and how each is utilized in the overall generation fleet."

Request 14bi. Provide a copy of all engineering or other technical analysis that supports the use of two different life spans for similar generating units (Smith 1-3 v Smith 4-10 and Bluegrass Oldham 1-3. In addition, indicate when each such analysis was performed, the purpose for which it was performed, who developed or conducted the analysis, and the actual use of the analysis, if any, other than to support the life spans for depreciation purposes.

Response 14bi. There are not specific engineering or other technical analyses performed to establish a depreciable life span for combustion turbines. There were many factors that went into the analysis of the appropriate life span to use for EKPC's production facilities. These factors were discussed in the response to AG-Nucor 1-23. Examples of these key factors are: number of starts, efficiency of the units, how the unit is dispatched, and how can the unit meet the peaking demand. The current depreciation rates being utilized by EKPC are based on the same life span for each Smith Unit as recommended in this depreciation study. There haven't been any major changes to EKPC's plans related to these units that would necessitate a change in life span at this time. Retirements of these types of units happen in the 30-40 year age range, thus the 40-year life span being utilized on the newer Smith units is on the longer side of the typical industry range. Given the way EKPC utilizes Units 1-3, and the efficiencies of all the Smith units, it is expected that Units 1-3 (which were placed in service earlier than the other units) would have a somewhat shorter expected life span than the other Smith units.

Units 1-3 are larger units and take longer to get to full capacity to meet the demand of peaking requirements, so they have different overhaul cycles and consequently the overall life cycle is shorter.

Request 14bii. Provide a copy of the "EKPC plans for all the Smith units" cited in the response.

Response 14bii. The "plan" refers to how EKPC intends to operate its combustion turbine fleet in the PJM Market. There is no plan to operate those units differently in the future than EKPC does today.

EXHIBIT___(LK-18)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
INITIAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR INITIAL REQUEST FOR INFORMATION DATED 5/14/21
REQUEST 20
RESPONSIBLE PERSON: **Michelle K. Carpenter**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 20. Provide a monthly trial balance schedule for each month in 2018, 2019, 2020, and 2021 to date listing all accounts and subaccounts and month-end balances. Provide annual sums for each of the accounts and subaccounts and in total for each calendar year requested. In addition, provide the data in electronic format with all formulas intact and provide data in a monthly side by side comparison if possible.

Response 20. Please see pages 3 through 10 of this response and corresponding Excel spreadsheet *AG Nucor DR1 Response 20.xlsx* for all general ledger account balances for the years ended December 31, 2018, 2019, and 2021 to date. It should be noted that EKPC only provided year-end balances for 2018 through 2020 and year-to-date 2021 as its standard monthly trial balance reports provide year-to-date balances of all revenue and expense accounts, not monthly activity. However, monthly RUS Form 12 information, including operating statements, for 2019 through April 2021 have been provided in Response 40.

EKPC objects to the request for 40 months of trial balances as this is duplicative of financial information already provided in this case, responses to this and other current requests for information, or information available from annual and auditor's reports available on the Commission's website. Without waiving its objection, EKPC is providing its annual trial balances for 2018, 2019, 2020, and the first four months of 2021.

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Trial Balance Schedule
As of and for the Years Ending 2018, 2019, 2020 and Four Months Ending 4/30/2021

ACCOUNT		Year Ending 12/31/2018	Year Ending 12/31/2019	Year Ending 12/31/2020	Period Ending 04/30/2021
105000	Elec Plant Held for Future Use	27,461.55	27,461.55	27,461.55	27,461.55
106000	Compltd Const Not Classfd-Elec	95,227,803.20	111,390,347.73	283,657,429.61	264,865,463.99
106001	Equipment Purchases	946,026.63	1,603,534.00	6,875,505.50	574,483.80
107200	WIP-Construction & Contract	93,330,427.58	247,392,629.69	192,838,014.87	198,402,305.30
108110	Accum Deprec-Steam-Lab	(1,264,894.02)	(1,303,406.37)	(1,343,651.74)	(1,357,066.86)
108130	Accum Deprec-Steam-Cooper	(189,058,747.84)	(205,497,782.74)	(222,748,018.96)	(228,494,602.04)
108140	Accum Deprec-Steam-Splk Common	(16,310,440.30)	(19,138,436.93)	(22,517,855.81)	(23,939,577.30)
108141	Accum Deprec-Steam-Splk 1	(207,311,323.63)	(216,105,542.33)	(226,792,486.76)	(230,862,818.43)
108142	Accum Deprec-Steam-Splk 2	(308,654,812.50)	(320,872,613.52)	(333,893,608.57)	(338,846,362.55)
108143	Accum Deprec-Steam-Gilbert	(141,658,671.40)	(152,053,571.21)	(162,036,349.78)	(165,671,528.26)
108144	Accum Deprec-Steam-Splk 4	(126,189,141.13)	(119,812,241.77)	(130,805,938.58)	(134,913,474.71)
108410	Accum Deprec-Oth Prd-SM CT Com	(31,478,584.82)	(33,342,242.04)	(35,166,460.47)	(35,786,060.19)
108411	Accum Deprec-Oth Prd-SM CT 1	(15,864,598.84)	(16,444,425.26)	(17,144,342.88)	(17,378,122.24)
108412	Accum Deprec-Oth Prd-SM CT 2	(15,242,840.18)	(15,760,082.33)	(16,397,774.12)	(16,611,333.38)
108413	Accum Deprec-Oth Prd-SM CT 3	(15,680,765.99)	(16,232,333.63)	(16,918,330.37)	(17,144,736.32)
108414	Accum Deprec-Oth Prd-SM CT 4	(16,886,983.87)	(17,735,688.15)	(18,614,478.77)	(18,907,408.97)
108415	Accum Deprec-Oth Prd-SM CT 5	(14,713,208.95)	(15,466,657.93)	(16,219,263.65)	(16,470,132.13)
108416	Accum Deprec-Oth Prd-SM CT 6	(8,184,547.49)	(8,759,356.31)	(9,333,439.22)	(9,524,800.54)
108417	Accum Deprec-Oth Prd-SM CT 7	(8,097,538.85)	(8,665,390.67)	(9,232,516.63)	(9,421,558.87)
108419	Accum Deprec-Oth Prd-SM CT 9	(14,235,681.32)	(15,911,637.14)	(17,663,676.56)	(17,794,961.42)
108420	Accum Deprec-Oth Prd-SM CT 10	(15,129,779.64)	(16,676,540.38)	(17,400,209.47)	(17,252,973.18)
108450	Accum Depr-Oth Prd-OC CT Com	(5,431,864.38)	(5,837,669.70)	(6,542,386.13)	(7,744,537.05)
108451	Accum Depr-Oth Prd-OC CT 1	(25,418,254.08)	(26,964,792.97)	(28,532,366.53)	(29,160,018.30)
108452	Accum Depr-Oth Prd-OC CT 2	(24,269,940.71)	(25,812,116.49)	(27,399,211.37)	(28,021,447.76)
108453	Accum Depr-Oth Prd-OC CT 3	(22,890,077.41)	(24,282,772.08)	(25,743,508.90)	(26,342,222.32)
108460	Accum Deprec-Oth Prd-Landfill	(8,844,340.70)	(9,085,206.58)	(9,832,993.08)	(10,082,277.06)
108465	Accum Deprec-Oth Prd-Solar	(830,666.13)	(1,512,215.12)	(2,210,160.54)	(2,442,808.98)
108490	Accum Deprec-Oth Prd-Diesl Gen	(1,474,056.11)	(1,554,212.20)	(1,615,229.85)	(1,635,569.09)
108500	Accum Deprec-Transmission Plnt	(213,381,155.33)	(221,082,673.12)	(228,047,657.49)	(229,840,807.91)
108600	Accum Deprec-Distribution Plnt	(94,194,967.33)	(99,648,607.08)	(105,214,721.04)	(107,299,875.47)
108700	Accum Deprec-General Plant	(84,419,843.49)	(90,240,506.71)	(87,900,302.07)	(85,862,741.96)
108705	Accum Deprec-Software	(15,775,549.73)	(16,399,856.63)	(16,947,272.15)	(17,111,070.67)
108800	Retirement Work in Progress	9,834,456.98	17,438,512.59	17,900,948.82	13,622,502.69
108902	AccDepr AssetRetOblg	(19,792,009.52)	(18,907,453.70)	(24,157,389.57)	(25,161,498.41)
108911	AccDepr AssetRetCost-Lab	92,613.55	92,613.55	92,613.55	92,613.55
108913	AccDepr AssetRetCost-Cooper	850,753.08	1,174,145.24	1,174,145.24	1,174,145.24
108914	AccDepr AssetRetCost-Splk	59,623,935.90	61,480,441.40	62,002,522.14	62,063,925.75
108915	AccDepr AssetRetCost-Gilbert	9,988,425.75	66,910,266.92	71,830,043.32	71,830,043.32
108917	AccDepr AssetRetCost-CT Units	3,248,324.59	4,308,327.96	7,561,734.20	10,971,486.34
108918	AccDepr AssetRetCost-LF Units	13,754.46	1,057,660.74	1,057,660.74	1,057,660.74
108950	AccDepr AssetRetCost-Trns Plt	17,316,036.21	22,206,360.67	24,248,623.24	28,014,422.61
108960	AccDepr AssetRetCost-Dist Plt	7,924,918.22	8,301,815.03	10,999,111.99	11,577,392.49
108970	AccDepr AssetRetCost-Genrl Pl	902,482.59	1,025,565.13	2,570,164.56	3,518,548.61
111000	Accum Amort-Elec Utility Plant	(1,206,246.47)	(1,126,863.04)	(1,184,037.44)	(1,203,095.56)
111700	Accum Amort-Elect Leased Plant	-	(7,657.03)	(53,599.20)	(68,913.24)
114000	Electric Plant Acquisition Adj	4,019,664.03	4,019,664.03	4,019,664.03	4,019,664.03
115000	Accum Amort-Elec Plnt Acq Adj	(535,955.20)	(714,606.93)	(893,258.67)	(952,809.23)
121001	Nonutility Property-Transm	819.75	819.75	819.75	819.75
123100	Patronage Cap from Assoc Coop	2,001,321.64	2,311,809.99	2,637,867.52	2,682,091.59
123221	Invstmt in CFC Cap Subord Trm	8,210,939.68	8,124,519.38	7,373,483.49	7,287,063.19
123230	Oth Invst in Assoc Organizatns	626,724.56	626,724.56	626,724.56	626,724.56
123231	Oth Invst-Low Int Ln Prg-Coops	93,935.64	208,195.82	241,118.13	258,847.83
123234	Oth Invst-Coop Propane Buyout	929,005.48	411,527.43	163,874.48	106,165.94
124005	Oth Invst-Lake Cumberlnd Devlp	100.00	100.00	100.00	100.00
124006	Oth Invst-PatCap Assgn Nonassc	114,228.28	113,506.06	112,425.16	112,425.16
124053	Oth Invst-Poll Ctrl Bnd-Cooper	1,089,132.48	1,104,819.17	1,103,107.08	1,103,052.04
124054	Oth Invst-Poll Bnd Disc-Cooper	(2,552.01)	(1,641.01)	(25.73)	(7.26)

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Trial Balance Schedule
As of and for the Years Ending 2018, 2019, 2020 and Four Months Ending 4/30/2021

ACCOUNT		Year Ending 12/31/2018	Year Ending 12/31/2019	Year Ending 12/31/2020	Period Ending 04/30/2021
124080	Oth Invst-LT Rec-Inlnd Contain	3,242,204.76	2,260,924.20	1,202,062.64	838,407.31
128001	Oth Spec Fnds-Defrd Compensatn	4,286,015.85	3,446,519.58	4,490,710.39	4,659,441.16
128002	Oth Spec Fnds-Resrv Defrd Comp	(4,286,015.85)	(3,446,519.58)	(4,490,710.39)	(4,659,441.16)
128005	Oth Spec Fnds-Escr Dep Bnk One	40,086,484.55	38,311,156.24	38,865,950.69	38,875,867.59
128006	Oth Spec Fnds-TVA Deposit	-	667,451.52	1,105,407.57	1,105,534.98
128007	Oth Spec Fnds-Escr BG Oldham	3,000,000.00	-	-	-
131101	Cash-Genrl-PNC Bank Kentucky	17,575,858.17	8,670,323.37	17,564,343.59	17,055,111.71
131102	Cash-Genrl-PNC Prop Casualty	8,650.56	12,023.80	21,187.96	34,125.49
131103	Cash-Genrl-PNC Payroll	7,594.57	7,594.57	7,594.57	7,594.57
131104	Cash-Genrl-PNC Coop Solar	3,249.25	15,111.42	36,966.67	41,851.22
131105	Cash-MMDA-USBank	10,000,000.00	5,000,000.00	250,000.00	250,000.00
131106	Cash-MMDA-TraditionalBank	-	5,008,501.22	5,001,486.57	5,001,438.48
131200	Cash-Construction Fund-Trustee	500.00	500.00	500.00	500.00
131201	Cash-Construction Fund-Solar	-	-	-	-
134001	Other Special Deposits	425.00	425.00	425.00	425.00
134002	Special Deposit-PJM	2,196,076.52	1,731,894.47	1,738,175.15	1,738,277.06
135000	Working Funds	7,215.30	7,215.30	7,215.30	7,215.30
135002	Workng Fnds-Spec ROW Procuremt	15,411.53	31,164.24	22,283.44	15,424.29
135005	Workng Fnds-Medical Insurance	1,250,898.32	459,930.67	757,599.94	1,246,876.16
135006	Workng Fnds-Self Funded Dental	478,716.69	478,716.69	478,716.69	478,716.69
135007	Workng Fnds-Sec 125 Flex Spend	90,898.86	101,696.91	124,970.15	132,449.49
136001	Temp Cash Invst-Treasury Bills	95,000,000.00	111,000,000.00	100,000,000.00	95,000,000.00
142100	Cust Accounts Receivable-Elec	85,357,327.42	80,926,647.25	83,332,571.89	58,860,522.00
143001	Oth Accts Rec-General	1,790,894.83	112,492.46	295,948.26	450,551.14
143003	Oth Accts Rec-Coop Loan Prgm	-	-	-	-
143004	Oth Ac/Rec-Coop Propane Buyout	-	-	3,504.61	-
143005	Oth Accts Rec-Job Orders	10,950.17	125,740.86	282,426.77	1,929,416.88
143006	Oth Accts Rec-Workers Comp Ins	1,222,000.00	2,771,000.00	3,296,000.00	3,296,000.00
143011	Oth Accts Rec-Coop Med Insurnc	(247,835.24)	1,196,479.04	1,217,850.20	299,608.37
143028	Oth Accts Rec-COBRA	-	-	-	2,314.20
151002	Fuel Stock-Cooper	12,409,014.65	17,263,148.69	14,226,745.39	9,611,653.47
151006	Fuel Stock-Inventory Adjustmnt	1,952,347.39	(2,487,507.36)	-	-
151007	Fuel Stock-Limestone Inv Adj	26,437.78	49,280.41	174,417.10	58,139.03
151008	Fuel Stock-Coal-Miscellaneous	3,048,636.85	5,334,632.66	2,840,009.92	-
151010	Fuel Stock-Oil-Smith CT	3,236,667.00	3,221,492.16	3,176,396.50	3,813,333.11
151017	Fuel Stock-Oil-Bluegrass	-	-	1,306,985.58	1,677,815.31
151018	Fuel Stock-Gilbert	11,802,837.42	16,988,753.32	10,815,736.28	10,454,411.25
151020	Fuel Stock-Scrubber Coal	13,726,373.65	24,628,469.74	12,140,790.15	11,292,526.57
151028	Fuel Stock-Limestone-Gilbert	287,366.72	392,334.96	249,015.79	208,580.02
151029	Fuel Stock-Limestone-Sp 2 Scrb	210,515.35	210,126.30	210,066.56	262,508.47
151038	Fuel Stock-TDF Gilbert	-	7,557.90	2,975.02	9,029.71
151040	Fuel Stock-Mercontrol 8034	124,163.02	115,742.54	103,785.52	149,086.33
151041	Fuel Stock-Mercontrol 7895	18,444.64	19,249.29	64,827.09	64,827.09
151050	Fuel Stock-Ammonia Spurlock	91,373.77	52,132.94	14,349.72	32,176.09
151090	Fuel Stock (CB)	564,387.18	377,942.24	434,827.55	651,334.08
152000	Fuel Stock Exps Undistributed	665,150.02	696,937.69	893,533.54	659,759.22
154000	Plnt Matls/Op Supp-General	56,865,918.91	56,318,422.20	71,903,314.26	69,936,214.57
154001	Plnt Matls/Op Supp-Poles	424,377.02	439,621.64	409,457.72	673,826.95
154003	Plnt Matls/Op Supp-OCR	1,816,966.49	1,469,336.38	742,220.45	970,120.28
154004	Plnt Matls/Op Supp-Tran Reg	5,876,732.27	5,552,043.67	4,877,191.36	6,224,169.54
154006	Plnt Matls/Op Supp-ETS Hrdwr	30,682.95	30,017.46	30,063.48	30,669.81
154011	Plnt Matls/Op Supp-EK Computrs	2,499.26	2,658.26	2,282.76	2,282.76
154020	Plnt Matls/Op Supp-Gasoline	45,033.42	22,633.76	23,481.28	29,061.64
154099	Temp Asset Recd/Not Stocked	(193,053.86)	(101,809.69)	(293,109.82)	(293,109.82)
158100	Allowance Inventory	589,394.89	561,307.44	536,676.87	529,090.23
165100	Prepayments-Insurance	3,838,557.04	4,399,647.76	4,179,348.18	1,705,430.03
165102	Prepymts-24Hr Businss Trvl Ins	-	-	-	271.68
165103	Prepymts-Term Life Insurance	-	-	-	295,733.91

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Trial Balance Schedule
As of and for the Years Ending 2018, 2019, 2020 and Four Months Ending 4/30/2021

	ACCOUNT	Year Ending 12/31/2018	Year Ending 12/31/2019	Year Ending 12/31/2020	Period Ending 04/30/2021
165200	Oth Prepymts-Misc Exp-Subsq Yr	8,096,087.52	7,818,947.87	2,514,202.47	4,248,429.18
171000	Int/Div Rec-CFC	93,167.57	93,167.57	87,954.82	28,759.50
171001	Int/Div Rec-Genrl Fnd Investmt	105,956.40	89,377.24	1,148.76	3,551.67
171008	Int/Div Rec-Poll Contrl-Cooper	3,237.80	2,739.67	2,235.42	568.51
171009	Int/Div Rec-Pledged Escrow	457.76	452.87	-	-
175000	Derivative Instrument Assets	(495,124.35)	(77,693.02)	(2,359.56)	(1,166.36)
181001	Unamrt Debt Exp-Private PI Bon	917,364.43	881,121.43	844,878.43	830,464.11
181005	Unamrt Debt Exp-Coopr PC IssCs	46,395.69	36,364.29	26,332.89	23,726.45
181006	Unamrt Debt Exp-Sr Cr Facility	1,281,772.04	1,229,215.52	878,011.04	706,961.40
181007	Unamrt Debt Exp-CREB's	221,410.04	177,128.12	132,846.20	118,085.56
181008	Unamrt Debt Exp-Priv Plac 2019	-	1,083,912.35	1,047,139.79	1,032,548.95
182200	Unrecovered Plant-Dale	262,065.47	-	-	-
182201	Unrecovered Plant-Dale-ES	749,484.07	749,484.07	749,484.07	749,484.07
182302	Other Regulatory Asset-FAC	-	-	1,424,317.65	-
182303	Other Regulatory Asset-ES	-	-	-	546,226.00
182306	Other Regulatory Asset-SM CFB	123,506,200.73	88,847,396.40	64,796,705.59	60,884,390.85
182320	Oth Reg A - Dale 1&2 Asbestos	942,592.15	325,657.58	325,657.58	325,657.58
182321	Oth Reg A - Dale 3&4 Asbestos	4,571,241.79	1,034,892.92	1,034,892.92	1,034,892.92
182322	Oth Reg A - Cooper Asbestos	122,715.96	453,247.87	787,910.91	900,895.95
182330	Oth Reg A-Dale Ash	14,070,332.55	12,614,780.91	11,159,229.27	10,674,045.39
182331	Oth Reg A-Spur Ash Pond	13,382,100.80	18,012,148.99	22,682,788.34	23,404,865.44
182332	Oth Reg A-Spur Landfill	3,241,746.52	3,707,515.49	4,096,717.60	4,232,699.56
182333	Oth Reg A-Cooper Landfill	1,529,309.75	1,651,043.10	1,626,105.62	1,619,977.93
182334	Other Reg A-Dale Ash Hauling	-	-	-	-
182335	Oth Reg A-Smith Landfill	168,691.99	256,958.81	348,000.64	379,315.57
182350	Oth Reg A-Spurlock 2019 Major	-	7,244,183.74	6,338,661.00	6,036,820.00
183000	Prelim Survey/Invstgation Chgs	536,541.38	579,028.58	742,109.80	619,325.39
184100	Clearing-Transportation Exps	-	-	-	41,190.01
186050	Misc Def Debit-Other	466,249.65	958,700.39	1,306,638.34	518,814.70
186060	Misc Def Debt-Solar Lic O&M	1,631.00	4,210.95	4,659.95	3,349.95
189001	Unamort Loss Reaquir Debt- RUS	6,333,367.53	6,135,449.85	5,937,532.17	5,871,559.61
200000	Memberships Issued	(1,600.00)	(1,600.00)	(1,600.00)	(1,600.00)
201101	Patronage Capital Credits	(648,671,724.00)	(691,061,470.00)	(713,799,202.90)	(713,799,202.90)
201201	Patronage Capital Assignable	40,668,788.40	44,204,037.47	28,691,907.88	-
208001	Donated Capital	(3,034,924.10)	(3,034,924.10)	(3,034,924.10)	(3,034,924.10)
209001	Accum Oth Comprehensive Income	(12,123,030.00)	(21,209,309.00)	(27,454,700.00)	(27,454,700.00)
215101	Unrealzd Gn/Loss-Debt/Eqty Sec	41,408.63	(64,341.36)	(1,032.57)	(401.75)
221000	Bonds	(207,225,999.68)	(350,873,465.12)	(339,507,055.94)	(329,059,305.01)
224121	Oth LTD-CFC	-	(100,000,000.00)	(96,666,666.67)	(93,333,333.34)
224122	Oth LTD-NCSC	(7,411,270.00)	(5,575,041.00)	(4,239,219.00)	(3,860,553.20)
224140	Oth LTD-Misc-Gfathered Sick Lv	(188,698.51)	(130,773.57)	-	-
224150	Oth LTD-Sr Credit Facility	(320,000,000.00)	(185,000,000.00)	(245,000,000.00)	(200,000,000.00)
224300	LTD-RUS Notes Executed	(2,537,158,389.80)	(2,280,401,967.02)	(2,384,863,320.45)	(2,367,414,992.12)
224400	RUS Notes Exec-Constr-Debit	145,378,000.00	108,495,000.00	508,814,000.00	494,681,000.00
224600	Advance Pmts Unappld-LTD-Debit	505,654,386.67	349,593,355.60	704,845.57	714,137.63
227000	Capital Lease Obl-Non-current	-	(180,141.91)	(136,835.54)	(122,095.66)
228300	Pens/Bnfts-Resve-Retire Medcal	(66,053,264.93)	(57,552,923.14)	(51,150,942.46)	(51,331,285.10)
228301	Pens/Bnfts-Resve-Deferred Comp	(653,419.72)	(587,675.71)	(552,125.17)	(442,103.62)
228303	Pens/Bnfts-Resv-Annuity,LTD,WC	(1,610,000.00)	(3,286,000.00)	(3,656,000.00)	(3,656,000.00)
228304	Pens/Bnfts-Resve-Dental Insur	(40,000.00)	(36,000.00)	(33,000.00)	(32,066.69)
228305	Pens/Bnfts-Flex Spend Hea Care	(87,164.58)	(98,111.27)	(115,060.80)	(126,498.82)
228306	Pens/Bnfts-Flex Spend Dep Care	(3,174.77)	(2,575.11)	(8,825.09)	(4,650.98)
228307	Pens/Bnfts-401K Employee Contr	(76,871.55)	(74,741.66)	(78.91)	(75,478.34)
228308	Pens/Bnfts-401K 4% Emple Contr	(91,803.87)	(106,343.15)	-	(120,709.72)
228311	Pens/Bnfts-401K Employer Contr	(14,772.09)	(13,810.92)	5,122.76	(13,070.31)
228312	Pens/Bnfts-401K 4% Emplr Contr	(48,273.99)	(53,226.08)	-	(62,579.15)
228313	Pens/Bnfts-401K 6% Emplr Contr	(78,431.20)	(84,340.65)	-	(97,919.59)
228330	Pens/Bnfts-Med PPO	(641,566.72)	(904,994.33)	(841,618.65)	(1,973,850.76)

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228331	Pens/Bnfts-Retiree Med-PPO	(249,029.58)	(268,119.10)	(118,099.32)	(282,184.91)
228360	Pens/Bnfts-Drug Chg-Active	(3,295.77)	(8,042.99)	(3,046.57)	556,840.34
228361	Pens/Bnfts-Drug Chg-Retiree	(2,866.56)	(7,353.99)	(405.53)	97,101.21
228362	Pens/Bnfts-Vision	(24,000.00)	(29,000.00)	(27,000.00)	(8,765.26)
228363	Pens/Bnfts-Allstate Pln	61.64	(89.80)	(475.43)	(263.50)
228364	Pens/Bnfts-Sh.Term Disability	(16,193.35)	-	-	-
228368	HSA Employee Contribution	-	(360.00)	325.00	-
228369	HSA Employer Contribution	-	2,600.00	3,400.00	3,920.00
230002	Asset Retirement Oblig-Steam	(9,013,684.14)	(2,833,555.00)	(2,943,765.79)	(2,981,933.43)
230003	Asset Retirement Oblg-Ash	(48,137,591.36)	(50,007,480.23)	(42,269,998.15)	(42,443,114.65)
230004	Asset Retirement Oblg-LFPostCl	(3,128,895.85)	(3,478,181.38)	(3,637,296.16)	(3,692,762.16)
232100	Accounts Payable-General	(80,199,859.04)	(115,447,673.53)	(83,278,590.83)	(67,791,509.92)
232102	Misc Liability Rec Insp	(576,587.69)	(534,761.59)	(536,812.90)	(913,665.42)
232103	Expenses Payable	(14,239.61)	(10,622.34)	(8,145.60)	(1,000.47)
236100	Accrued Property Taxes	(144,152.40)	(268,000.00)	(496,149.20)	(4,491,787.48)
236200	Accrued FUTA	(603.07)	(684.71)	(600.07)	(218.20)
236300	Accrued FICA/SS Medicare	(5,921.84)	(13,024.07)	(25,147.20)	(441,329.11)
236400	Accrued SUTA	(1,072.05)	(1,793.48)	(1,637.54)	(1,822.52)
236500	Accrued State Sales Tax	(176,350.43)	(254,675.83)	(324,904.74)	(92,029.46)
237000	Interest Accrued	(4,047,489.67)	(8,090,065.61)	(7,585,996.32)	(7,627,837.19)
241000	Tax Coll Payable-FIT	(309.80)	(309.80)	(35,688.10)	(361,362.79)
241005	Tax Coll Payable-SIT	(121,125.69)	(4,584.32)	(5,563.55)	(127,569.45)
241011	Tax Coll Payable-Clark PR	18.00	18.00	18.00	(53,324.23)
241012	Tax Coll Payable-Pulaski PR	(19,986.12)	(20,162.94)	(18,944.12)	(6,925.49)
241013	Tax Coll Payable-Mason PR	(115,431.69)	(126,123.10)	(141,957.88)	(56,817.32)
241014	Tax Coll Payable-Nelson PR	(83.77)	(60.58)	(85.24)	(109.13)
241015	Tax Coll Payable-Laurel PR	(211.69)	(267.80)	(260.09)	(106.87)
241016	Tax Coll Payable-Boone PR	-	(168.02)	(18.18)	(85.87)
241017	Tax Coll Payable-Pendleton PR	(102.19)	(31.17)	(231.64)	(85.95)
241018	Tax Coll Payable-Frankfort PR	(693.98)	(296.32)	(379.37)	(108.51)
241019	Tax Coll Payable-Grant Co PR	(634.93)	(543.23)	(510.75)	(233.38)
242200	Accrued Payroll	(1,538,435.16)	(1,878,705.52)	(2,605,012.05)	(1,078,635.40)
242300	Accrd Empl Compensated Absnces	(1,716,806.97)	(1,849,850.49)	(3,518,558.58)	(3,518,558.58)
242500	Oth Curr/Accr Liab-Svg Bond PR	(400.00)	(400.00)	(400.00)	(400.00)
242502	Oth Curr/Accr Liab-Un Fnd PR	15,640.00	1,600.00	1,600.00	-
242503	Other Curr/Accr Liab-EAssoc PR	-	20.00	-	-
242504	Oth Curr/Accr Liab-Misc	(68,546.80)	(3,000.00)	(199,168.67)	(199,168.67)
242505	Oth Curr/Accr Liab-401K Ln PR	(48,311.25)	(50,075.96)	238.96	(50,731.68)
242506	Oth Curr/Accr Liab-Homestead	1,200.00	1,200.00	875.00	1,200.00
242508	Oth Curr/Accr Liab-ACRE	(69.94)	(1,049.54)	(69.94)	(689.98)
242510	Oth Curr/Accr Liab-Supple Life	-	-	-	106,530.39
242512	Oth Curr/Accr Liab-Family AD&D	-	-	-	29,622.15
242513	Other Curr/Accr Liab-FTR	(45,208.83)	(2,411.56)	3,739.18	712.22
243000	Capital Lease Obl-Current	-	(43,306.37)	(43,306.37)	(43,306.37)
252000	Customer Advances-Construction	-	-	-	(5,695,490.71)
253007	Oth Defd Cr-Solar Pnl Lic Fee	(400,069.29)	(416,485.75)	(421,500.07)	(426,560.07)
253008	Oth Defd Cr-Solar Lic Energy	(445.00)	(388.00)	(431.00)	(1,189.00)
253009	Oth Defd Cr-Solar Lic REC	(1,960.00)	(5,085.65)	(5,097.65)	(4,021.65)
253010	Oth Defd Cr-Solar Lic Capacity	-	363.00	-	-
253130	Other Defd Capacity Prepaids	-	-	-	-
254002	Other Regulatory Liab-FAC	(3,676,285.00)	(2,740,919.00)	-	(2,094,561.12)
254003	Other Regulatory Liab-ES	(873,985.00)	(1,032,992.00)	(2,389,225.00)	-
301000	Organization	5,040.43	5,040.43	5,040.43	5,040.43
303001	Misc Intang Plnt-Ghent Trn Twr	27,405.00	27,405.00	27,405.00	27,405.00
303002	Misc Intang Plnt-TVA Int Summe	210,302.40	210,302.40	210,302.40	210,302.40
303003	Misc Intang Plnt-Pleasant Gr M	51,387.36	51,387.36	51,387.36	51,387.36
303004	Misc Intang Plnt-KU Lynch Sw	573,252.35	547,151.21	547,151.21	547,151.21
303005	Misc Intang Plnt-Wolfe St Corp	13,225.80	13,225.80	13,225.80	13,225.80

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303006	Misc Intang Plnt-KU/Lake Reba	849,440.38	849,440.38	849,440.38	849,440.38
303007	Misc Intang Plnt-N Madison Tap	66,238.90	66,238.90	66,238.90	66,238.90
303008	Misc Intang Plnt-Zimmer	159,000.00	159,000.00	159,000.00	159,000.00
303009	Misc Intang Plnt-Stuart	409,160.00	409,160.00	409,160.00	409,160.00
303010	Misc Intang Plnt-LGE Tolling	146,000.00	-	-	-
310000	Land/Land Rights-Steam Prd	35,119,191.80	35,252,142.07	39,996,027.11	41,443,222.65
311000	Struct & Improvemts-Steam Prd	388,627,867.82	389,165,111.36	394,092,442.29	394,092,442.29
312000	Boiler Plant Equip-Steam Prd	1,577,030,095.59	1,574,736,513.36	1,589,361,807.09	1,599,568,391.23
314000	Turbogenerator Unit-Steam Prd	318,970,611.82	253,537,266.81	278,497,130.90	279,823,215.73
315000	Accessory Elec Equip-Steam Prd	114,787,888.51	114,287,420.43	115,678,520.24	115,678,520.24
316000	Misc Pwr Plant Equip-Steam Prd	13,344,011.42	15,703,954.91	15,882,149.90	15,944,884.73
317000	Asset Retire Costs-Steam Prod	9,367,767.34	2,668,860.62	2,668,860.62	2,668,860.62
317001	Asset Retire Costs-Ash	45,728,775.48	47,245,172.00	38,294,734.72	38,294,734.72
317002	Asset Retire Costs-LFPostClos	2,864,152.00	3,069,547.00	3,069,547.00	3,069,547.00
340000	Land & Land Rights-Oth Pwr Prd	5,924,091.19	5,964,035.69	5,964,035.69	5,964,035.69
341000	Struct & Improvmts-Oth Pwr Prd	51,973,228.63	52,871,798.04	52,931,816.51	52,931,816.51
342000	Fuel Hldrs/Accessr-Oth Pwr Prd	20,033,575.25	20,033,575.25	20,033,575.25	20,033,575.25
343000	Prime Movers-Oth Pwr Prd	405,884,096.97	406,211,866.10	406,525,614.99	405,419,084.10
344000	Generators-Oth Pwr Prd	86,690,134.57	103,150,557.26	103,150,557.26	103,150,557.26
345000	Accessory Elec Eq-Oth Pwr Prd	37,512,599.27	38,288,055.69	38,310,828.65	38,238,757.24
346000	Misc Pwr Plt Equip-Oth Pwr Prd	15,990,208.41	15,990,208.41	16,264,537.20	16,264,537.20
350000	Land/Land Rights-Transm Plant	4,688,859.26	4,688,859.26	4,688,859.26	4,688,859.26
350010	Land/Lnd Rghts-Easemts-TransPl	55,533,399.23	55,719,148.42	56,677,637.86	56,907,931.24
353000	Station Equipment-Trans Plant	257,918,882.60	259,426,782.31	271,329,998.86	275,258,134.63
353010	Station Equip-ECS-Trans Plant	9,655,734.89	9,476,611.16	9,906,956.69	9,903,048.01
354000	Towers & Fixtures-Trans Plant	3,853,520.91	3,853,520.91	3,853,520.91	3,853,520.91
355000	Poles & Fixtures-Trans Plant	148,734,704.13	150,851,436.29	157,775,914.45	172,439,720.19
356000	Overhd Conductors/Devices-Tran	130,459,690.62	132,608,503.00	132,934,424.23	136,394,644.80
359000	Roads and Trails-Trans Plant	23,287.65	23,287.65	23,287.65	23,287.65
360000	Land/Land Rights-Distr Plant	10,334,487.10	10,063,490.41	10,063,490.41	10,198,880.48
362000	Station Equipment-Distr Plant	203,756,634.89	212,368,871.92	222,294,086.85	226,488,595.89
362001	Station Equip-SCADA-Distr Plnt	5,946,980.39	5,957,706.56	7,376,293.13	7,376,293.13
368000	Line Transformers-Distr Plant	1,985,006.09	1,985,006.09	2,413,995.98	2,413,995.98
389000	Land/Land Rights-General Plant	1,381,311.62	1,381,311.62	1,381,311.62	1,381,311.62
389001	Land/Land Rights-Radio Towers	454,290.88	454,290.88	454,290.88	454,290.88
390000	Struct & Improvmts-General Plt	17,033,657.12	17,176,820.18	17,229,528.61	17,229,528.61
391000	Office Furn & Equip-Genrl Plnt	9,646,381.81	10,667,305.83	12,227,570.67	12,619,810.52
391001	Office Furn & Equip-PeopleSoft	17,080,999.94	17,298,493.67	17,577,003.88	18,586,688.97
391100	Office Furn & Equip - Leased	-	229,710.85	229,710.85	229,710.85
392000	Transportation Equip-Genrl Plt	16,015,571.74	17,294,890.14	18,797,214.65	18,872,549.99
393000	Stores Equipment-General Plant	126,083.46	132,973.46	132,973.46	132,973.46
394000	Tools, Shop & Garage Equipment	2,038,281.38	2,313,149.79	2,449,002.46	2,451,353.36
395000	Lab Equipment-General Plant	5,179,718.87	5,311,175.70	5,467,980.30	5,467,980.30
396000	Power Operated Equip-Genrl Plt	19,946,551.38	20,685,598.42	21,314,969.33	21,319,777.41
397000	Communication Equip-Genrl Plnt	40,586,849.45	41,370,762.43	37,084,056.21	36,272,711.10
397001	Communication Eq-ECS-Genrl Plt	642,538.48	642,538.48	612,404.47	612,404.47
398000	Misc Equipment-General Plant	2,415,833.71	2,428,472.92	2,630,483.76	2,636,506.49
403100	Deprec Exp-Steam Plant	65,830,306.78	65,596,902.10	67,540,541.81	23,992,892.83
403410	Deprec Exp-Oth Prd Plt-CT's	13,448,630.38	14,425,071.37	15,525,524.31	6,328,101.93
403420	Deprec Exp-Oth Prd Plt-Ldfills	634,639.36	697,589.69	662,904.56	220,989.93
403430	Deprec Exp-Oth Prd Plt-Dsl Gen	81,358.01	80,156.09	61,017.65	20,339.24
403440	Deprec Exp-Oth Prd Plt-Solar	722,240.78	681,548.99	697,945.42	232,648.44
403500	Deprec Exp-Transm Plant	9,624,436.03	9,697,504.32	9,908,603.34	3,418,378.47
403600	Deprec Exp-Distrib Plant	7,245,631.68	7,512,194.35	7,932,786.14	2,711,343.33
403700	Deprec Exp-Generl Plant	7,220,740.94	7,930,028.51	9,196,113.03	2,772,841.58
403702	Deprec Exp-Generl Plant-Nonreg	643.92	643.92	643.92	214.64
403800	Deprec Exp-Asset Retire Costs	451,842.73	2,025,756.88	2,358,892.66	786,297.68
404000	Amortization-Leased Elec Plant	-	7,657.03	45,942.17	15,314.04

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405000	Amortization-Intangible Plant	57,920.11	52,016.55	57,174.40	19,058.12
407000	Amortization-Unrecovered Plant	12,567,094.65	12,168,157.44	12,035,524.68	3,599,757.13
408700	Taxes-Other	190,098.88	118,995.07	266,510.62	36,251.16
409120	Income Taxes-Other States	1,200.00	1,200.00	1,200.00	1,200.00
411100	Accretion Expense	(21,102.06)	390,859.64	538,256.28	179,418.79
411600	Gains/Disposition of Util Plnt	(404,962.50)	(1,308,876.32)	-	-
411800	Gains/Disposition of Allownces	(45.11)	(43.00)	(15.25)	-
412000	Rev Elec Plnt Leased to Others	(10,831,974.60)	(4,008,204.02)	(590,777.00)	(194,903.00)
413100	Oper Exp Plt Leased Excld Fuel	1,129,957.63	463,473.12	127,410.12	44,045.63
413101	Oper Exp Plt Leased Oth-Fuel	112,718.87	111,717.09	130,457.05	41,463.56
413102	Oper Exp Plt Leased Prop Tax	204,626.92	182,077.06	13,064.13	1,092.00
413200	Maintenance Exp Plnt Lease Oth	557,290.79	229,853.94	73,897.89	26,340.45
413300	Depr Exp Plnt Leased Oth	1,596,256.50	587,725.29	84,881.94	28,294.05
413400	Amort Exp Plnt Leased Oth	43,800.00	14,600.02	-	-
417101	Exps/Nonutil Oper-Other/ACES	2,651.29	1,724.36	182.85	-
417103	Exps/Nonutil Oper-Envision	33,457.38	31,169.71	35,435.74	19,422.83
419000	Int/Div Income-Regulated	(27,658,512.54)	(25,302,329.08)	(12,643,410.24)	(182,206.10)
419002	Interst Income-Inlnd Container	(42,383.77)	(122,038.20)	(80,079.68)	(15,991.75)
419010	Int/Div Income-Nonregulated	(43,630.06)	(29,436.28)	(11,640.87)	(1,309.90)
421000	Misc Nonoper Incm-Other-Reg	1,364,136.10	1,178,734.28	(330,013.11)	(67,712.03)
421100	Gain/Disposition of Prop-Reg	(147,814.37)	(70,799.34)	(203,341.85)	(19,126.10)
421200	Loss/Disposition of Prop-Reg	21,286.38	46,492.16	9,481.72	-
424000	Oth Cap Creds & Patr Cap Alloc	(233,047.14)	(634,843.00)	(692,204.79)	(155,026.93)
425000	Miscellaneous Amortization	178,651.74	178,651.73	178,651.74	59,550.56
426100	Donations	165,280.00	160,655.84	130,786.37	10,500.00
426200	Life Insurance	(2,944.77)	-	-	-
426300	Penalties	-	-	-	-
426400	Civic,Political & Related Actv	27,550.40	12,251.71	12,255.76	1,139.86
426500	Oth Deductns-Regulated	622,385.80	694,242.01	847,763.89	-
427000	Interest on Long-Term Debt	115,438,973.90	112,361,639.67	100,921,594.54	28,961,192.75
428001	Amrt Debt Disc/Exp-Priv.PlBond	36,243.00	36,243.00	36,243.00	12,081.00
428005	Amrt Debt Disc/Exp-PCB-Cooper	10,031.40	10,031.40	10,031.40	3,343.80
428006	Amrt Debt Disc/Exp-Sr Cr Facil	376,144.14	358,712.52	351,204.48	117,068.16
428007	Amrt Debt Disc/Exp-CREB	44,281.92	44,281.92	44,281.92	14,760.64
428008	Amrt Debt Disc/Exp-Priv.Pl2019	-	27,308.21	36,772.56	12,257.52
428101	Amort Loss Required Debt- RUS	6,037.53	197,917.68	197,917.68	65,972.56
431010	Other Interest Exps-Regulated	11.00	57.00	101.00	-
431020	Other Interest Exps-Nonreg	-	-	-	24,075.20
431030	Other Interest Exps-Leased	-	1,054.80	6,396.55	1,827.76
447100	Sales/Resale-RUS Borr-Mbr Coop	(845,982,608.00)	(813,897,219.00)	(743,008,399.00)	(284,926,565.00)
447103	Sales/Resale-RUS Borr-Mbr-GPwr	(61,641.00)	(49,170.00)	(46,575.00)	(15,155.00)
447142	Sales/Resale-MbrCoop-Accrd FAC	5,128,862.00	(922,108.00)	(676,769.00)	1,177,216.00
447143	Sales/Resale-MbrCoop-Accrd ES	(1,183,950.00)	164,922.00	1,379,911.00	(2,884,472.00)
447250	Sales/Resale-Non RUS-Off Sys	(28,549,317.35)	(19,579,619.44)	(18,340,495.49)	(9,115,502.43)
447251	Misc Capacity Sales	(3,508,025.78)	(6,330,055.95)	(10,865,179.82)	(3,074,653.16)
451001	Misc Service Revenues-Reg	33.01	(3,987.54)	(4,107.45)	6,191.04
454001	Rent from Elec Property-Reg	(191,559.14)	(171,398.80)	(169,316.82)	(63,061.73)
456003	Oth Elec Rev-Sales Tax Compens	(600.00)	(600.00)	(600.00)	(200.00)
456010	Oth Elec Rev-Steam Sales-Inlnd	(11,124,024.00)	(10,687,040.00)	(10,399,384.00)	(4,005,670.00)
456042	Oth Elec Rev-Steam-Accrd FAC	85,825.00	(13,258.00)	(17,258.00)	27,523.00
456043	Oth Elec Rev-Steam-Accrd ES	(37,711.00)	(5,915.00)	(23,678.00)	(50,979.00)
456054	Facility Chgs-Cagles	(43,200.00)	(43,200.00)	(43,200.00)	(14,400.00)
456057	Facility Chgs-Big Sandy-Inez	(54,870.96)	(54,870.96)	(54,870.96)	(18,290.32)
456080	Oth Elec Rev-Solar Pnl License	(13,872.51)	(17,310.24)	(18,784.18)	-
456101	TS Revenue-Wheeling	(141,447.00)	(106,774.50)	(110,839.50)	(43,465.50)
456130	TS Revenue-Non Firm Pt to Pt	(2,896,984.22)	(3,470,050.11)	(3,258,169.79)	(746,540.58)
456131	TS Revenue-Anc Svc-Sched 3.1	(162,435.95)	(141,300.16)	(172,869.09)	(72,806.39)
456132	TS Revenue-Anc Svc-Sched 3.2	(88,331.47)	(87,601.85)	(77,099.39)	(26,886.88)

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Trial Balance Schedule
As of and for the Years Ending 2018, 2019, 2020 and Four Months Ending 4/30/2021

	ACCOUNT	Year Ending 12/31/2018	Year Ending 12/31/2019	Year Ending 12/31/2020	Period Ending 04/30/2021
459000	Rev/Sale of Renewbl Engy Credt	(630,780.64)	(697,751.65)	(1,174,010.37)	(530,664.50)
500000	Oper Supv/Engr-Steam Gen	7,520,384.87	8,546,343.43	9,233,986.38	3,200,205.66
501010	Fuel-Steam Generation-Coal	181,683,181.84	141,669,184.38	158,362,040.13	68,304,942.22
501020	Fuel-Steam Generation-Oil	3,191,450.14	3,247,009.87	1,755,464.58	847,312.92
501060	Fuel-Steam Generation-TDF	998,399.25	595,356.65	705,709.09	344,117.86
502000	Steam Expenses-Steam Gen	11,751,846.54	11,892,275.94	11,699,692.95	3,909,821.28
505000	Electric Expenses-Steam Gen	5,512,248.68	5,916,155.27	6,196,374.00	2,129,470.01
506001	Misc Steam Power Exps	27,073,806.82	22,992,426.53	25,812,888.17	10,600,328.31
506002	Misc Steam Power Exps-Environ	5,054,523.56	5,258,343.71	5,186,079.09	1,282,259.36
509000	Allowances	22,866.45	28,087.45	24,630.57	7,586.64
510000	Mntc Supv/Engr-Steam Gen	3,197,975.56	3,310,824.94	3,413,566.42	1,151,950.95
511000	Mntc of Structures-Steam Gen	5,975,328.81	6,286,688.00	5,135,413.29	1,431,281.85
512000	Mntc of Boiler Plant-Steam Gen	57,601,659.98	56,898,527.66	50,449,925.59	14,581,314.87
513000	Mntc of Elec Plant-Steam Gen	7,468,664.57	10,909,960.49	8,408,959.44	1,979,166.87
546000	Oper Supv/Engr-Oth Power Gen	2,317,411.69	3,287,392.90	3,247,861.12	1,099,381.11
547020	Fuel-Oth Power Gen-Oil	430,270.77	15,174.84	45,095.66	304,676.49
547030	Fuel-Oth Power Gen-Natural Gas	22,331,518.39	16,431,545.57	10,535,810.31	10,410,365.04
547040	Fuel-Oth Power Gen-Methane Gas	737,389.48	645,363.39	720,598.03	248,119.50
547050	Fuel-Oth Power Gen-Diesel	3,008.59	3,238.36	(799.52)	1,124.39
548000	Generation Exps-Oth Power Gen	5,082,726.09	5,783,337.64	6,590,042.40	2,376,925.16
549001	Misc Other Power Gen Expenses	1,498,368.46	2,257,183.82	2,274,690.00	682,693.86
549002	Misc Oth Pwr Gen Exps-Environ	1,594,610.56	1,639,395.78	2,016,958.86	580,246.67
551000	Mntc Supv/Engr-Oth Power Gen	364,010.22	416,604.16	532,019.75	205,648.65
552000	Mntc of Structures-Oth Pwr Gen	902,026.19	828,318.08	1,104,872.45	204,387.67
553000	Mntc of Gen&Elec Equip-Oth Gen	11,209,792.07	8,765,788.41	7,215,827.06	5,813,179.38
555000	Purchased Power	171,730,934.52	176,617,390.77	109,217,461.24	42,784,754.27
555001	Purchased Power-Solar License	12,180.00	15,399.38	14,518.00	4,352.00
556000	System Ctrl & Load Dispatching	4,512,322.19	4,821,880.41	5,340,768.51	1,900,500.88
557001	Oth Pwr Supp Ex-LTerm Pwr Supp	2,503,021.45	2,519,452.69	2,794,289.59	877,397.11
557002	Oth Pwr Supp Ex-Load Forecastg	807,393.62	699,835.58	645,532.65	161,649.09
557003	Oth Pwr Supp Ex-Broker Fees	2,258,900.22	2,282,256.00	2,331,993.96	774,493.68
559000	Renewable Energy Cred Expenses	-	1,154.72	337.25	-
560000	Oper Supv/Engr-Transm Expenses	10,270,225.05	10,174,845.25	10,706,984.98	3,363,706.44
561000	Trans Exp-Load Dispatching	3,337,022.18	4,007,823.70	4,273,254.58	1,342,388.77
562000	Trans Exp-Station Expenses	3,066,127.86	2,915,004.55	2,575,345.44	859,009.10
563000	Trans Exp-Overhead Line Exps	5,777,113.56	6,617,560.68	6,191,540.99	2,665,529.07
565000	Transmission of Elec By Others	8,689,706.17	8,713,043.09	15,602,396.24	7,325,450.15
566000	Misc Transmission Expenses	416,023.53	389,702.96	822,795.06	322,045.26
567000	Transmission Expense-Rents	446,268.84	446,268.84	431,903.28	90,501.84
568000	Mntc Supv/Engr-Transm Exps	298,891.82	224,852.43	222,632.21	50,894.71
570000	Mntc of Station Equip-Trans Ex	2,187,717.56	2,843,300.50	2,403,540.83	952,239.40
571000	Mntc of Ovhead Lines-Trans Exp	5,846,890.12	6,096,952.78	5,558,732.30	1,968,049.83
573000	Mntc of Misc Transmission Plnt	161,342.98	176,042.47	71,843.36	17,262.68
575700	Mrkt Admin.Monitor/Compliance	5,243,735.56	4,746,963.93	4,671,657.11	2,047,397.52
581000	Distrib Exp-Load Dispatching	230,723.14	226,841.71	212,586.55	68,116.80
582000	Distrib Exp-Station Expenses	1,297,462.39	1,511,689.10	1,433,269.58	438,516.34
592000	Mntc of Station Equip-Dist Exp	2,227,789.68	2,929,641.12	2,667,829.84	685,342.40
908000	Cust Assistance Exps-Regulated	9,575,935.45	6,223,953.12	4,551,012.07	1,328,549.28
909000	Info/Instr Advrtg-Sfty,Tech,Co	39,988.37	42,859.44	46,263.76	13,358.95
910000	Info/Instr Advrtg-Env Educ-Reg	-	24,906.67	48,305.85	660.63
913000	Sales Exps-Advrtg Exp-Reguitd	60,943.48	68,233.29	46,605.61	25,711.27
920000	Administrative/Generl Salaries	17,921,225.17	18,272,350.89	19,645,596.14	6,982,389.19
921000	Gen/Admin Offc Supplies & Exps	8,651,601.50	8,563,344.13	6,965,662.82	2,513,326.92
923001	Outside Services-Regulated	3,534,120.01	2,314,944.21	2,443,678.65	934,354.68
925000	Injuries and Damages	1,110,694.70	1,140,505.94	1,286,938.87	403,170.54
926000	Employee Pensions and Benefits	2,801,716.32	2,606,666.54	1,038,508.38	433,846.64
928000	Regulatory Commisn Exps-KY PSC	1,642,804.69	1,699,128.57	1,668,748.48	-
929001	Dupl Chgs-CR-Electric HD WH	(517,549.00)	(476,963.00)	(411,229.00)	(167,017.00)

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Trial Balance Schedule
As of and for the Years Ending 2018, 2019, 2020 and Four Months Ending 4/30/2021

ACCOUNT		Year Ending 12/31/2018	Year Ending 12/31/2019	Year Ending 12/31/2020	Period Ending 04/30/2021
930100	General Advertising Expense	768,999.54	658,804.07	290,087.47	148,804.05
930200	Misc Gen Exps-Directors Fees	779,465.17	790,621.35	623,224.25	241,370.19
930201	Misc Gen Exps-Dues-Regulated	2,194,647.30	2,335,391.07	2,400,800.65	863,272.60
930202	Misc Gen Exps-Member PR-Regltd	990,297.34	812,715.18	668,981.24	186,602.87
930203	Misc Gen Exps-Tax Ins Alloc	579,562.87	520,933.90	515,297.09	138,273.08
930204	Misc Gen Exps-Labor Exp RD-Reg	111,698.00	136,882.87	184,814.38	19,925.04
935000	Maint/General Plant-Winchester	3,034,297.66	2,732,236.33	1,990,660.37	715,157.05

EXHIBIT___(LK-19)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 33
RESPONSIBLE PERSON: Isaac S. Scott / Michelle K. Carpenter
COMPANY: East Kentucky Power Cooperative, Inc.

Request 33. Refer to Schedule 1.20 entitled Adjustment to Amortize Smith 1 Regulatory Asset.

Request 33a. Update the schedule for PJM capacity market benefits and capacity performance insurance premiums for 2020 actual amounts, 2021 year to date actual amounts, and budgeted, or if not budgeted, then estimated 2021 remaining year amounts through September 2021.

Response 33a. Schedule 1.20 – Adjustment to Amortize Smith 1 Regulatory Asset, is based upon the Stipulation Agreement approved by the Commission in Case No. 2015-00358.[4] The August 6, 2016 Stipulation Agreement described the "Smith Solution" that addressed the issues of returning the PJM Capacity Market Benefits to owner-members and their retail members and the amortization of the Smith 1 regulatory asset.

[4] *See In the Matter of Application of East Kentucky Power Cooperative, Inc. for Deviation from Obligation Resulting from Case No. 2012-00169*, Case No. 2015-00358, Order (Ky. P.S.C. Jan. 10, 2017).

The Stipulation Agreement specifically addressed how EKPC was to determine an amortization adjustment for Smith 1 in its next general base rate proceeding. Section 1.2.5 states:

> As part of its next general base rate proceeding, EKPC shall request that its rates be adjusted to reflect the amortization expense of the Smith 1 Regulatory Asset. This amortization adjustment shall be spread over the remaining months of the 10-year amortization period that began on January 1, 2017, and shall be based on the Smith 1 Regulatory Asset balance as of January 1, 2017, reduced by: (i) the actual results of EKPC's mitigation and salvage efforts during the period of January 1, 2017, through the end of the test year employed in the rate case; and (ii) the Net PJM Capacity Market Benefit earned by EKPC beginning with the 2016/2017 PJM Delivery Year and concluding at either the end of the test year employed in the rate case or the end of calendar year 2019. This latter determination shall be made depending on whether, at the time of EKPC's next general base rate proceeding, the PJM Capacity Market Costs associated with calendar year 2019 are known and measurable. If they are, EKPC shall request an amortization adjustment that reflects the full Net PJM Capacity Market Benefit realized through 2019. . . For cost-of-service purposes, the amortization expense of the Smith 1 Regulatory Asset will be treated like other capacity related costs (e.g., power plant depreciation).

Nucor, represented by the Kentucky Industrial Utility Customers, Inc., and the Attorney General ("AG") are signatories to the Stipulation Agreement. The Commission approved the Stipulation Agreement in total on January 10, 2017.

The test year in this proceeding is calendar year 2019. Updating Schedule 1.20 as requested goes beyond the provisions of Section 1.2.5 of the Stipulation Agreement that Nucor and the AG signed. Therefore, EKPC respectfully declines to provide the requested update to Schedule 1.20.

Request 33b. Update the schedule provided in response to part (a) of this question to show the annual amortization expense for 2017 through 2020 actual amounts, 2021 year to date actual amounts, and budgeted, or if not budgeted, then estimated 2021 remaining year amounts through September 2021. If there was no annual amortization expense in 2017, 2018, 2019, 2020, or 2021 year to date, then explain why not and cite to all authorities relied on to not record amortization expense.

Response 33b. As noted in the response to part (a) of this request, the determination of the Smith 1 Regulatory Asset amortization adjustment is dictated by the provisions of Section 1.2.5 of the Stipulation Agreement. The book amortization expenses are not part of the determination of the adjustment. Notwithstanding this provision, EKPC is providing the annual amortization expense for 2017 through 2020 and the actual amounts for 2021 year to date. Please see page 7 of this response. However, EKPC filed its rate case utilizing a historic test year rather than a forecasted test year. The standard for adjustments to a historic test year is that the adjustment is "known and measurable". Rate cases utilizing a forecasted test year rely on budgets and forecasts for adjustments. As this case was filed utilizing a historic test year, the budgeted 2021 or estimated 2021 amortization expense is not provided.

Request 33c. Explain why the Company did not show reductions in the regulatory asset or the annual amortization expense on this schedule.

Response 33c. Rows 14 through 17 of Schedule 1.20 reflect the reductions to the regulatory asset related to salvage, mitigation, and other credits and reversed accruals for the period 2017 through 2020. Although Section 1.2.5 of the Stipulation Agreement only required recognition of mitigation and other adjustments through 2019, EKPC voluntarily included the 2020 mitigation and credits. The book annual amortization expense was not reflected on this schedule because it is not a component of the determination of the amortization adjustment as detailed in Section 1.2.5 of the Stipulation Agreement.

Request 33d. Provide the per books balances at January 1, 2017, December 31, 2017, December 31, 2018, December 31, 2019, December 31, 2020, and each month in 2021 year to date.

Response 33d. Please see page 7 of this response for the requested book balances.

Request 33e. Refer to line 31 on this schedule. Explain why the 2019 PJM capacity market benefits were shown as a positive amount, adding to the regulatory asset balance, instead of a negative amount, reducing the regulatory asset balance.

Response 33e. The PJM Capacity Market Benefits reflects not only the revenues received from selling capacity but also the charges associated with purchasing the required load obligation capacity from the PJM Base Residual and Incremental Auctions.

An additional consideration was noted in EKPC's first status report on efforts between EKPC, the Kentucky Industrial Utility Customers, Inc., the AG, and the Commission Staff to reach a consensus on the flow-back of the PJM Capacity Market Benefits in Case No. 2015-00358. In first status report, dated January 14, 2016, EKPC noted on page 4 that:

> EKPC's generation assets are all bid into the PJM capacity market auctions. All generation asset costs are recovered in base rates, with the exception of the Bluegrass Station units, which are expected to be paid for by PJM capacity market benefits. Therefore, it would be appropriate to exclude the Bluegrass Station units from any capacity market benefit flow-back.

In 2019, the combination of selling capacity and purchasing required load obligation capacity in PJM coupled with the exclusion of the Bluegrass Station units from the capacity market benefit resulted in a net capacity market charge rather than a net capacity benefit. Thus, this net charge was shown as a positive amount in Schedule 1.20.

Request 33f. Refer to the response to AG-Nucor 1-20. Confirm that the regulatory asset balance at April 30, 2021 recorded on the Company's accounting books is $60.884 million. If confirmed, then explain why the amortization expense requested in this proceeding should be based on the $73.2 million regulatory asset balance calculated on Schedule 1.20 and not the recorded or estimated balance at September 30, 2021, which will be substantially less than even the $60.884 million at April 30, 2021.

Response 33f. EKPC confirms that the Smith 1 Regulatory Asset balance at April 30, 2021 is $60.884 million. The amortization expense requested in this proceeding was determined consistent with Section 1.2.5 of the Stipulation Agreement in Case No. 2015-00358. As parties to that Stipulation Agreement, Nucor and the AG agreed to the methodology to be utilized to determine the amortization adjustment, which did not include a consideration of the outstanding regulatory asset balance as of September 30, 2021 or any other date.

East Kentucky Power Cooperative, Inc.
Case No. 2021-00103
Smith 1 Regulatory Asset Amortization Expense and Book Balances

Amortization Expense

	Total 2017	$12,021,443.37
	Total 2018	$12,030,093.03
	Total 2019	$12,035,524.68
	Total 2020	$12,035,524.68
	YTD April 2021	$3,599,757.13

Regulatory Asset Balances

	January 1, 2017	$148,833,974.80
	December 31, 2017	$135,617,411.88
	December 31, 2018	$123,506,200.73
	December 31, 2019	$88,847,396.40
	December 31, 2020	$64,796,705.59
	January 31, 2021	$63,896,751.04
	February 28, 2021	$62,996,796.80
	March 31, 2021	$62,092,692.56
	April 30, 2021	$60,884,390.85

EXHIBIT___(LK-20)

1400 East Kentucky Power Cooperative, Inc. 01/01/2019 - 12/31/2019

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$4,198,018,962.00	$4,181,966,162.00
3, Construction Work in Progress (107)	$93,330,427.00	$247,392,630.00
4. TOTAL UTILITY PLANT	$4,291,349,389.00	$4,429,358,792.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$1,554,631,786.00	$1,558,959,449.00
6. Net Utility Plant	$2,736,717,603.00	$2,870,399,343.00
7. Nuclear Fuel (120.1-120.4,120.6)	$0.00	$0.00
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	$0.00	$0.00
9. Net Nuclear Fuel	$0.00	$0.00
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$2,736,717,603.00	$2,870,399,343.00
11. Utility Plant Adjustments (116)	$0.00	$0.00
12. Gas Stored Underground - Non Current (117)	$0.00	$0.00
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)	$820.00	$820.00
15. (Less) Accum. Prov. for Depr and Amort. (122)	$0.00	$0.00
16. Investment in Associated Companies (123)	$9,860,605.00	$9,370,967.00
17. Investments in Subsidiary Companies (123.1)	$2,001,322.00	$2,311,810.00
18.		
19. Noncurrent Portion of Allowances	$0.00	$0.00
20. Other Investments (124)	$4,443,114.00	$3,477,708.00
21. Special Funds (125-128)	$43,086,484.00	$38,978,608.00
22. TOTAL Other Property and Investments	$59,392,345.00	$54,139,913.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$27,595,853.00	$18,714,054.00
25. Special Deposits (132-134)	$2,196,502.00	$1,732,320.00
26. Working Fund (135)	$1,843,140.00	$1,078,724.00
27. Temporary Cash Investments (136)	$95,000,000.00	$111,000,000.00
28. Notes Receivable (141)	$0.00	$0.00
29. Customer Accounts Receivable (142)	$85,357,327.00	$80,926,647.00
30. Other Accounts Receivable (143)	$2,776,010.00	$4,205,712.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$0.00	$0.00
32. Notes Receivable from Associated Companies (145)	$0.00	$0.00

1001200 Duke Energy Kentucky, Inc. 01/01/2019 - 12/31/2019

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$2,399,457,684.00	$2,633,071,836.00
3, Construction Work in Progress (107)	$118,766,446.00	$114,642,467.00
4. TOTAL UTILITY PLANT	$2,518,224,130.00	$2,747,714,303.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$992,560,885.00	$1,005,243,913.00
6. Net Utility Plant	$1,525,663,245.00	$1,742,470,390.00
7. Nuclear Fuel (120.1-120.4,120.6)	$0.00	
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)	$0.00	
9. Net Nuclear Fuel	$0.00	$0.00
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$1,525,663,245.00	$1,742,470,390.00
11. Utility Plant Adjustments (116)	$0.00	
12. Gas Stored Underground - Non Current (117)	$0.00	
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)	$985,844.00	$1,231,001.00
15. (Less) Accum. Prov. for Depr and Amort. (122)	$0.00	
16. Investment in Associated Companies (123)	$0.00	
17. Investments in Subsidiary Companies (123.1)	$0.00	
18.		
19. Noncurrent Portion of Allowances	$0.00	
20. Other Investments (124)	$1,500.00	$1,500.00
21. Special Funds (125-128)	$7,330,598.00	$9,774,894.00
22. TOTAL Other Property and Investments	$8,317,942.00	$11,007,395.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$7,772,710.00	$7,145,664.00
25. Special Deposits (132-134)	$0.00	
26. Working Fund (135)	$0.00	
27. Temporary Cash Investments (136)	$0.00	
28. Notes Receivable (141)	$0.00	
29. Customer Accounts Receivable (142)	$4,925,759.00	$4,902,218.00
30. Other Accounts Receivable (143)	$6,089,935.00	$2,527,496.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$220,841.00	$313,942.00
32. Notes Receivable from Associated Companies (145)	$23,069,663.00	$16,029,153.00

300 Kentucky Power Company 01/01/2019 - 12/31/2019

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$2,732,212,005.00	$2,880,228,456.00
3. Construction Work in Progress (107)	$84,747,789.00	$98,671,345.00
4. TOTAL UTILITY PLANT	$2,816,959,794.00	$2,978,899,801.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$969,035,246.00	$1,026,166,192.00
6. Net Utility Plant	$1,847,924,548.00	$1,952,733,609.00
7. Nuclear Fuel (120.1-120.4,120.6)		
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)		
9. Net Nuclear Fuel		
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$1,847,924,548.00	$1,952,733,609.00
11. Utility Plant Adjustments (116)		
12. Gas Stored Underground - Non Current (117)		
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)	$6,670,698.00	$6,670,698.00
15. (Less) Accum. Prov. for Depr and Amort. (122)	$239,662.00	$224,833.00
16. Investment in Associated Companies (123)		
17. Investments in Subsidiary Companies (123.1)		
18.		
19. Noncurrent Portion of Allowances	$8,555,112.00	$8,399,493.00
20. Other Investments (124)	$1,941,831.00	$1,887,770.00
21. Special Funds (125-128)	$15,818,892.00	$23,421,499.00
22. TOTAL Other Property and Investments	$32,746,871.00	$40,154,627.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$1,168,118.00	$848,841.00
25. Special Deposits (132-134)	$916,736.00	$618,051.00
26. Working Fund (135)		
27. Temporary Cash Investments (136)		
28. Notes Receivable (141)		
29. Customer Accounts Receivable (142)	$20,962,767.00	$15,019,912.00
30. Other Accounts Receivable (143)	$56,964.00	$145,236.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$85,487.00	$345,516.00
32. Notes Receivable from Associated Companies (145)		

400 Kentucky Utilities Company 01/01/2019 - 12/31/2019

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$9,559,622,667.00	$9,880,639,710.00
3. Construction Work in Progress (107)	$502,916,453.00	$495,780,054.00
4. TOTAL UTILITY PLANT	$10,062,539,120.00	$10,376,419,764.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$3,429,322,259.00	$3,464,339,891.00
6. Net Utility Plant	$6,633,216,861.00	$6,912,079,873.00
7. Nuclear Fuel (120.1-120.4,120.6)		
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)		
9. Net Nuclear Fuel		
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$6,633,216,861.00	$6,912,079,873.00
11. Utility Plant Adjustments (116)		
12. Gas Stored Underground - Non Current (117)		
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)	$612,836.00	$657,564.00
15. (Less) Accum. Prov. for Depr and Amort. (122)		
16. Investment in Associated Companies (123)		
17. Investments in Subsidiary Companies (123.1)	$250,000.00	$250,000.00
18.		
19. Noncurrent Portion of Allowances		
20. Other Investments (124)		
21. Special Funds (125-128)		$30,690,208.00
22. TOTAL Other Property and Investments	$862,836.00	$31,597,772.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$12,611,870.00	$9,833,693.00
25. Special Deposits (132-134)	$0.00	$0.00
26. Working Fund (135)	$61,030.00	$58,730.00
27. Temporary Cash Investments (136)	$960,025.00	$2,285,927.00
28. Notes Receivable (141)		$700,740.00
29. Customer Accounts Receivable (142)	$130,948,341.00	$140,210,928.00
30. Other Accounts Receivable (143)	$33,150,250.00	$25,791,511.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$1,603,257.00	$1,450,900.00
32. Notes Receivable from Associated Companies (145)	$2.00	$570.00

500 Louisville Gas and Electric Company 01/01/2019 - 12/31/2019

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$7,066,113,828.00	$7,598,517,749.00
3, Construction Work in Progress (107)	$513,967,016.00	$297,170,976.00
4. TOTAL UTILITY PLANT	$7,580,080,844.00	$7,895,688,725.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$2,248,094,904.00	$2,307,519,595.00
6. Net Utility Plant	$5,331,985,940.00	$5,588,169,130.00
7. Nuclear Fuel (120.1-120.4,120.6)		
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)		
9. Net Nuclear Fuel		
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$5,331,985,940.00	$5,588,169,130.00
11. Utility Plant Adjustments (116)		
12. Gas Stored Underground - Non Current (117)	$2,139,990.00	$2,139,990.00
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)	$679,575.00	$679,575.00
15. (Less) Accum. Prov. for Depr and Amort. (122)	$63,360.00	$63,360.00
16. Investment in Associated Companies (123)		
17. Investments in Subsidiary Companies (123.1)	$594,286.00	$594,286.00
18.		
19. Noncurrent Portion of Allowances		
20. Other Investments (124)		
21. Special Funds (125-128)		$31,615,059.00
22. TOTAL Other Property and Investments	$1,210,501.00	$32,825,560.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$9,806,384.00	$7,603,691.00
25. Special Deposits (132-134)		
26. Working Fund (135)	$24,790.00	$24,790.00
27. Temporary Cash Investments (136)	$195,522.00	$6,826,682.00
28. Notes Receivable (141)		$351,900.00
29. Customer Accounts Receivable (142)	$111,014,875.00	$122,048,652.00
30. Other Accounts Receivable (143)	$29,641,165.00	$40,117,145.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$1,444,910.00	$1,224,231.00
32. Notes Receivable from Associated Companies (145)		

900 Big Rivers Electric Corporation 01/01/2019 - 12/31/2019

Balance Sheet - Assets and Other Debits (Ref Page: 110)

	Balance Beginning of Year	Balance End of Year
1. UTILITY PLANT		
2. Utility Plant (101-106,114)	$2,166,465,503.00	$2,062,465,999.00
3, Construction Work in Progress (107)	$33,931,909.00	$35,662,645.00
4. TOTAL UTILITY PLANT	$2,200,397,412.00	$2,098,128,644.00
5. (Less) Accum. Prov. for Depr. Amort. Depl. (108,111,115)	$1,187,688,403.00	$1,193,042,964.00
6. Net Utility Plant	$1,012,709,009.00	$905,085,680.00
7. Nuclear Fuel (120.1-120.4,120.6)		$0.00
8. (Less) Accum. Prov. for Amort. of Nucl. Assemblies (120.5)		$0.00
9. Net Nuclear Fuel		$0.00
10. Net Utility Plant (Enter Total of Line 6 and Line 9)	$1,012,709,009.00	$905,085,680.00
11. Utility Plant Adjustments (116)		$0.00
12. Gas Stored Underground - Non Current (117)		$0.00
13. OTHER PROPERTY AND INVESTMENTS		
14. Nonutility Property (121)		$0.00
15. (Less) Accum. Prov. for Depr and Amort. (122)		$0.00
16. Investment in Associated Companies (123)	$43,995,138.00	$43,297,251.00
17. Investments in Subsidiary Companies (123.1)		$0.00
18.		
19. Noncurrent Portion of Allowances		$0.00
20. Other Investments (124)	$15,334.00	$15,334.00
21. Special Funds (125-128)	$7,613,568.00	$9,390,633.00
22. TOTAL Other Property and Investments	$51,624,040.00	$52,703,218.00
23. CURRENT AND ACCRUED ASSETS		
24. Cash (131)	$2,225,664.00	$1,308,001.00
25. Special Deposits (132-134)	$3,086,799.00	$1,770,425.00
26. Working Fund (135)	$3,725.00	$3,725.00
27. Temporary Cash Investments (136)	$45,843,947.00	$39,211,508.00
28. Notes Receivable (141)		$0.00
29. Customer Accounts Receivable (142)	$32,627,401.00	$30,479,418.00
30. Other Accounts Receivable (143)	$5,030,394.00	$7,846,841.00
31. (Less) Accum. Prov. for Uncollectible Acct. Credit (144)	$1,422,762.00	$1,422,762.00
32. Notes Receivable from Associated Companies (145)		$0.00

Big Rivers
ELECTRIC CORPORATION

STRENGTH
IN OUR CORE

2020 ANNUAL REPORT

FIVE-YEAR REVIEW

AS OF DECEMBER 31, 2020 AND THE FOUR PRECEDING YEARS

(DOLLARS IN THOUSANDS)

[1]Includes investment income receivable. [2]Includes current maturities of long-term obligations. [3]The reduction in Big Rivers' net generating capacity owned is due to the retirement of Reid Station Unit 1 and the units at Coleman Station as of September 30, 2020.

SUMMARY OF OPERATIONS	2020	2019	2018	2017	2016
Operating Revenue:					
Electric Energy Revenue	$314,390	$362,252	$366,190	$394,424	$390,357
Other Operating Revenue and Income	14,318	16,475	14,015	12,805	12,233
Total Operating Revenue	328,708	378,727	380,205	407,229	402,590
Operating Expenses:					
Fuel for Electric Generation	83,939	119,831	128,555	126,644	144,148
Power Purchased	35,756	37,893	51,910	100,045	80,341
Operations (Excluding Fuel), Maintenance and Other	114,605	123,062	130,153	110,606	115,606
Depreciation	54,630	49,356	20,709	20,301	19,523
Total Operating Expenses	288,930	330,142	331,327	357,596	359,618
Interest Expense and Other:					
Interest	33,393	36,937	38,568	40,654	40,711
Income Tax Expense/(Benefit)	(448)	(28)	(12)	7	(6,748)
Other-Net	830	696	717	744	846
Total Interest Expense and Other	33,775	37,605	39,273	41,405	34,809
Operating Margin	6,003	10,980	9,605	8,228	8,163
Non-Operating Margin	4,192	5,735	5,625	4,770	4,742
Net Margin	$10,195	$16,715	$15,230	$12,998	$12,905
SUMMARY OF BALANCE SHEET					
Total Utility Plant	$1,888,955	$2,098,129	$2,200,397	$2,179,899	$2,146,205
Accumulated Depreciation	1,102,333	1,193,043	1,187,688	1,138,133	1,094,235
Net Utility Plant	786,622	905,086	1,012,709	1,041,766	1,051,970
Cash and Cash Equivalents	20,400	30,733	38,466	55,861	48,584
Restricted Cash-Construction Funds Trustee	353	353	-	-	-
Short-Term Investments	6,603	9,437	9,607	9,223	5,913
Reserve Account Investments[1]	666	1,391	691	391	312
Other Assets	543,591	402,213	301,413	292,507	270,810
Total Assets	$1,358,235	$1,349,213	$1,362,886	$1,399,748	$1,377,589
Equities	$531,539	$523,164	$505,816	$490,887	$478,152
Long-Term Debt[2]	696,742	733,942	761,464	801,162	813,829
Line of Credit	-	-	-	20,000	26,000
Regulatory Liabilities - Member Rate Mitigation	33,334	2,111	2,031	403	327
Asset Retirement Obligations	40,410	34,557	29,746	28,347	7,279
Other Liabilities and Deferred Credits	56,210	55,439	63,829	58,949	52,002
Total Liabilities and Equity	$1,358,235	$1,349,213	$1,362,886	$1,399,748	$1,377,589
ENERGY SALES (MWh)					
Member Rural	2,164,850	2,261,069	2,366,988	2,209,836	2,330,007
Member Large Industrial	824,680	946,070	953,808	919,896	914,557
Other	1,898,036	2,879,231	3,101,659	4,291,555	4,414,268
Total Energy Sales (MWh)	4,887,566	6,086,370	6,422,455	7,421,287	7,658,832
SOURCES OF ENERGY (MWh)					
Generated	3,440,864	4,964,983	5,291,136	5,034,777	5,828,106
Purchased	1,520,984	1,166,472	1,149,102	2,411,882	1,874,584
Losses and Net Interchange	(74,282)	(45,085)	(17,783)	(25,372)	(43,858)
Total Energy Available (MWh)	4,887,566	6,086,370	6,422,455	7,421,287	7,658,832
NET CAPACITY (MW)					
Net Generating Capacity Owned[3]	936	1,444	1,444	1,444	1,444
Rights to HMP&L Station Two	-	-	187	197	197
Other Net Capacity Available	178	178	178	178	178
Total Net Capacity (MW)	1,114	1,622	1,809	1,819	1,819
DEBT RATIOS					
Margins for Interest Ratio (MFIR)	1.30	1.45	1.39	1.32	1.31
Times Interest Earned Ratio (TIER)	1.30	1.45	1.39	1.32	1.31
Debt Service Coverage Ratio (DSCR)	1.63	1.63	1.22	1.22	1.23

BIG RIVERS ELECTRIC CORPORATION

Balance Sheets

December 31, 2020 and 2019

(Dollars in thousands)

Assets		2020	2019
Utility plant – net	$	786,622	905,086
Restricted investments – Member rate mitigation		666	1,391
Restricted investments – NRUCFC Capital Term Certificates		—	31,609
Other deposits and investments		22,377	21,474
Current assets:			
Cash and cash equivalents		20,400	30,733
Restricted cash – construction funds trustee		353	353
Short-term investments		6,603	9,437
Accounts receivable		40,736	37,266
Fuel inventory		20,391	26,965
Nonfuel inventory		17,457	24,216
Prepaid expenses and other assets		5,129	4,298
Total current assets		111,069	133,268
Deferred charges and other assets:			
Regulatory assets		435,252	250,562
Federal tax receivable		—	54
Other		2,249	5,769
Total deferred charges and other assets		437,501	256,385
Total	$	1,358,235	1,349,213
Equities and Liabilities			
Capitalization:			
Equities	$	531,539	523,164
Long-term debt		663,780	706,269
Total capitalization		1,195,319	1,229,433
Current liabilities:			
Current maturities of long-term obligations		32,962	27,673
Purchased power payable		3,713	2,702
Accounts payable		23,535	22,328
Accrued expenses		9,345	9,054
Accrued interest		903	3,279
Regulatory liabilities – member rate mitigation		12,223	—
Total current liabilities		82,681	65,036
Deferred credits and other:			
Regulatory liabilities – member rate mitigation		1,111	2,111
Regulatory liabilities – TIER credit		20,000	—
Asset retirement obligations		40,410	34,557
Deferred credits and other		18,714	18,076
Total deferred credits and other		80,235	54,744
Commitments and contingencies (note 13)			
Total	$	1,358,235	1,349,213

See accompanying notes to financial statements.

EXHIBIT___(LK-21)

6. Long-Term Debt (continued)

reserve funds be on deposit with a trustee throughout the term of the bonds in the amount of \$1.1 million. In addition, mandatory sinking fund payments are required ranging from \$0.6 million in 2020 to \$0.7 million in 2023. Debt service reserve and construction funds are held by a trustee and are invested primarily in U.S. Government securities and CFC promissory notes. These funds are included in restricted investments on the accompanying Balance Sheets and have a fair value of approximately \$1.1 million at December 31, 2020 and 2019.

In January 2008, EKPC was approved to receive up to \$8.6 million to finance certain qualified renewable energy projects with Clean Renewable Energy Bonds. The loan was fully advanced in July 2009. The amount outstanding at December 31, 2020, is \$1.3 million.

In September 2016, EKPC was authorized by the IRS to issue \$19.8 million in New Clean Renewable Energy Bonds to finance a planned community solar facility. In February 2017, EKPC issued an \$18 million note to CFC. The amount outstanding as of December 31, 2020, is \$17.1 million.

Promissory Notes

On July 5, 2019, the Cooperative exercised its option to extend its existing \$600 million unsecured credit facility with CFC as the lead arranger, for an additional year. The facility consists of a \$500 million revolving tranche and a \$100 million term loan tranche. This facility matures on July 4, 2023, and is to be utilized for general corporate purposes including capital construction projects. As of December 31, 2020, the Cooperative had outstanding borrowings of \$245 million (including the \$100 million unsecured term loan). As of December 31, 2020, the availability under the credit facility was \$355 million.

In December 2010, the Cooperative entered into an unsecured loan agreement with the National Cooperative Services Corporation for \$23.8 million to refinance indebtedness to RUS. As of December 31, 2020, the amount outstanding under these notes is \$4.2 million.

EXHIBIT___(LK-22)

EAST KENTUCKY POWER COOPERATIVE, INC.
PSC CASE NO. 2021-00103
SUPPLEMENTAL REQUEST FOR INFORMATION RESPONSE

AG & NUCOR REQUEST FOR INFORMATION DATED 06/04/21
REQUEST 28
RESPONSIBLE PERSON: **Isaac S. Scott**
COMPANY: **East Kentucky Power Cooperative, Inc.**

Request 28. Refer to the electronic workpaper related to the Exhibit ISS-1 Schedule 1.02 Surcharge Adjustment included with the Company's filing. Refer further to the worksheet tab entitled "Interest and Principal." Finally, refer to the Direct Testimony of Mr. Scott at pages 13-14 related to the calculation of the adjustment to remove interest expense related to the environmental surcharge from the total interest expense.

Request 28a. Provide a detailed description of all reasons why this methodology of using an allocation of the specific environmental debt based on the net book value of the environmental rate base to quantify interest expense related to environmental surcharge projects instead of simply using EKPC's overall average interest rate in the return on rate base component of the environmental surcharge calculation.

Response 28a. The methodology utilized to determine the interest expense exclusion related to the environmental surcharge is based on the methodology used to determine the weighted average cost of debt component of the rate of return on environmental compliance rate base. The net book value of the environmental surcharge projects that are financed with long-term debt is used in the determination of the weighted average cost of debt. Please see the Excel spreadsheet *AG Nucor DR2 Response 28a.xlsx*, which is the calculation of the weighted average cost of debt EKPC filed in its most recent environmental surcharge review proceeding.[2]

Unlike the investor-owned electric utilities, EKPC is required by the RUS to initially finance its utility assets with general funds. Only after the asset has been completed, placed into service, and recorded in the accounting records as "planted" can it be eligible for long-term debt financing. When drawing down the long-term debt financing, EKPC must specifically identify the projects with the entity the debt issuances are associated. Thus, EKPC can match the projects in the environmental surcharge with the particular issuance of long-term debt.

Request 28b. Provide citations to any prior base cases or other cases in which this methodology was explicitly authorized by the Commission.

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[2] *See In the Matter of An Electronic Examination by the Public Service Commission of the Environmental Surcharge Mechanism of East Kentucky Power Cooperative, Inc. for the Two-Year Expense Period Ending May 31, 2019, and the Pass-Through Mechanisms of Its Sixteen Member Distribution Cooperatives*, Case No. 2019-00380, EKPC's Response to Commission Staff's First Request for Information, Request 5.

Response 28b. EKPC believes this methodology is consistent with the Commission's March 17, 2005 Order in Case No. 2004-00321[3] authorizing an environmental surcharge for EKPC. EKPC would also note that the methodology has been followed in the determination of the weighted average cost of debt component of the rate of return on environmental compliance rate base in every surcharge review proceeding conducted by the Commission since the start of the environmental surcharge.

Request 28c. Refer further to the amount of net book value of $627,033,240 included on the worksheet tab entitled "Interest and Principal" at cell J118. Reconcile this amount of net book value with the net book value of environmental plant reflected on the "Plant" and "AccDepr & Depr Exp" workbook tabs of $785,755,206 ($1,132,461,744 plant less $346,706,538 accumulated depreciation) describing all differences. If the two amounts should not match, explain why not.

Response 28c. Please see the Excel spreadsheet *AG Nucor DR2 Response 28c.xlsx* which reconciles the referenced net book values. The differences identified in column H of the spreadsheet reflect rounding differences. EKPC would note that the net book value of environmental plant stated in the request is in error, as it failed to recognize the accumulated amortization for Project 15 – Smith Special Waste Landfill. As noted at row

[3] *See In the Matter of Application of East Kentucky Power Cooperative, Inc. for Approval of an Environmental Compliance Plan and Authority to Implement an Environmental Surcharge*, Case No. 2004-00321, Order (Ky. P.S.C. Mar. 17, 2005).

66 of the "AccDepr & Depr Exp" workbook tab, the Commission authorized a 10-year amortization for this project. As noted in the response to Request 28a, projects recorded as CWIP are financed with general funds rather than long-term debt. In addition, EKPC elected to finance several of the projects with general funds rather than long-term debt. Concerning the Asset Retirement Obligation projects 12, 15, and 17, as these obligations are being settled, those project costs are financed with general funds rather than long-term debt.

Request 28d. Refer to the worksheet tab entitled "Interest and Principal." Indicate whether there are any amounts of outstanding debt, net book value, and/or interest expense by project associated with the amounts in CWIP (account 107), especially for project 16 (CCR/ELG) that sums to $129,093,455 on worksheet tab "Plant" at cell F41. If so, identify each such location in the spreadsheet. If there are no amounts, explain all reasons why not.

Response 28d. Three of the projects listed on the "Plant" worksheet tab have amounts in CWIP: Project 12 – Spurlock Landfill Area C; Project 16 – CCR/ELG; and Project 26 – Spurlock Coal Pile Retention Pond. As these projects still have amounts in CWIP, they must be financed with general funds and not long-term debt. Consequently, no projects with amounts in CWIP are included in the worksheet tab "Interest and Principal".

<u>Request 28e.</u> Refer to the worksheet tab entitled "Interest and Principal." Indicate whether there are any amounts of outstanding debt, net book value, and/or interest expense by project associated with projects 23 through 26 that are reflected on worksheet tab "Plant." If so, identify each such location in the spreadsheet. If there are no amounts associated with these projects, explain all reasons why not.

<u>Response 28e.</u> As noted on rows 114 through 116 of the worksheet tab "Interest and Principal", Projects 23 through 25 are included in this schedule of outstanding debt, net book value, and interest expense. Project 26 is still in CWIP, has been financed through the test year end with general funds, and is not included on the worksheet tab "Interest and Principal". Also, see the reconciliation provided in the Excel spreadsheet *AG Nucor DR2 Response 28c.xlsx*, rows 57 through 63.

EXHIBIT___(LK-23)

Focused Management and Operations Audit of East Kentucky Power Cooperative, Inc.

FINAL REPORT

Presented to:

The Kentucky Public Service Commission

By:

THE LIBERTY CONSULTING GROUP

The Liberty Consulting Group
65 Main Street, P.O. Box 1237
Quentin, Pennsylvania 17083-1237
admin@LibertyConsultingGroup.com

April 20, 2010

Table of Contents

I. Introduction

A. Engagement Background

The Kentucky Public Service Commission (Commission) issued a request for proposals seeking the conduct of a focused management and operations audit of East Kentucky Power Cooperative, Inc. (EKPC), a not-for-profit generation and transmission cooperative, headquartered in Winchester, Kentucky and owned by 16 member distribution cooperatives. EKPC and its more than 600 employees supply electric power to these 16 members and to non-member utilities as well. These 16 members serve over 500,000 member-consumers in eighty-seven Kentucky counties.

The Liberty Consulting Group (Liberty) responded to the Commission's request. Based in part upon EKPC's input, the Commission selected Liberty to perform the audit. Liberty is a management and technical consulting firm that specializes in the energy and telecommunications industries, in which the firm has operated for 23 years. Liberty has performed comprehensive and focused management audits, fuel and energy procurement and management audits, reviews of corporate governance in utility holding company structures, focused reviews of construction program expenditures and results, reliability assessments, and other consulting engagements for two-thirds of the country's state public service commissions and a number in Canada. Liberty's team for this audit included three very senior persons, who combine governance, management, financial, and operating backgrounds, and whose experience extends across a wide range of private and publicly owned power supply entities.

This report documents the results of Liberty's study, which it performed in accordance with the requirements of the request for proposals, as addressed in Liberty's proposal of April 3, 2009.

B. Recent EKPC Conditions and Circumstances

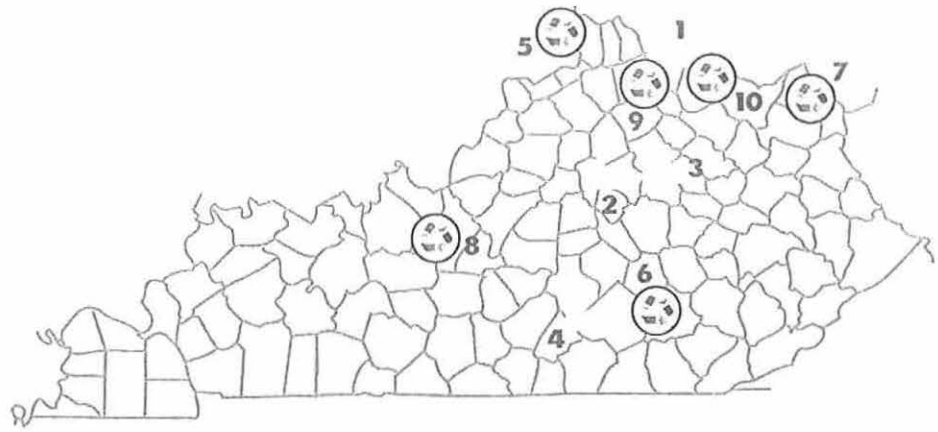
EKPC owns and operates 2,851 megawatts of electricity generating capacity, which it operates to provide capacity and energy to its 16 members. This capacity consists of:

- Three baseload coal-fired generating stations:
  - H.L. Spurlock Power Station (near Maysville)
  - John Sherman Cooper Power Station (near Somerset)
  - William C. Dale Power Station (near Winchester)
- Dual fuel peaking (natural gas and fuel-oil) combustion turbines (CTs) (at the J.K. Smith Power Station in Trapp, near Winchester). These facilities serve peak electric demand on the member systems.

EKPC also obtains about 170 megawatts of hydropower through arrangements with Laurel and Wolf Creek dams and the federal Southeastern Power Administration. In 2008, EKPC's 2008 winter peak reached 3,149 MW; its summer peak was 2,265 MW. EKPC owns and operates about 2,755 miles of high-voltage transmission lines required to deliver electricity to its 16 members. EKPC's most recent annual report listed total assets of about $2.8 billion.

Figure I.1 depicts EKPC's generation and transmission infrastructure and the retail area served by its members.

Figure I.1: EKPC Serving Region



Generating Unit Key	1: Spurlock	2: Dale	3: Smith
	4: Cooper	5-9: Landfill Gas Units	

The past five years have presented a number of changes and problems, which have challenged EKPC management and its board of directors, and which have illuminated many important aspects about EKPC's governance and the relationship that exists between senior management and the board.

Two major financial and operating problems occurred in 2004:

- A notice of violation that eventually led to a January 2006 EPA lawsuit against EKPC, alleging a violation of Acid-Rain environmental requirements at the cooperative's Dale generating station.
- A July 2004 forced outage at Spurlock #1, which caused EKPC to incur significant added costs (about $38 million) for repairs and to secure power to replace lost generation.

Late 2004 and early 2005 brought other significant changes to EKPC's power portfolio and increases in the financing required to support it. EKPC filed in October 2004 for a certificate of public convenience and necessity (CPCN) for a fourth unit at Spurlock (Case No. 2004-00423). Soon thereafter, in January of 2005, a CPCN application followed for Smith #1 and Combustion Turbines #8 through #12 (Case No. 2005-00053). The Commission granted the Spurlock #4 CPCN, recognizing the additional load EKPC would be serving as a result of the earlier addition of Warren Rural Electric Cooperative to those already being served by EKPC. Spurlock #3 (the Gilbert unit) became operational in April 2005. EKPC did not file a rate case to recover either the capital costs or operations and maintenance costs associated with the Gilbert facility.

These factors required significant new liquidity and short-term financing. In September 2005, EKPC entered into a $650 million unsecured line of credit (brokered by the National Rural Utilities' Cooperative Finance Corporation (CFC)) involving a group of 17 state, national, and international credit sources. Increased infrastructure needs continued. In October 2005, EKCP filed for a CPCN to install scrubbers at Spurlock #2 at an estimated cost of $142 million (Case No. 2005-00417). The 2005 year ended with the creation of a $32 million reserve by EKPC, at the request of its outside auditors, to address the potential environmental liability at Dale.

EKPC filed in January 2006 a CPCN application for a scrubber at Spurlock #1 (Case No. 2006-00132). The Commission approved the Spurlock #2 scrubber application in April, and later approved the Spurlock #1 scrubber in August. The Commission also granted in August 2006 the requested CPCN for Smith #1 and CTs #8 - #12, in anticipation of load growth in the member systems served by EKPC.

EKPC thus found itself, as 2006 progressed, facing large capital needs, not only for new sources of power, but also for environmental compliance at existing stations. These already large capital needs came with other major, potential consumers of EKPC's financial resources: the forced outage expenses and potential penalties from EPA.

Recognizing the severe strain of these events on EKPC's finances, the Commission initiated on October 27, 2006 a Financial Condition Investigation (Case No. 2006-00455), stating:

> *East Kentucky Power files monthly and annual financial reports with the Commission. A review of these reports indicates that East Kentucky Power's operations are producing negative net income since the last quarter of 2004. Based on the Commission's statutory authority under KRS 278.250 to "investigate and examine the condition of any utility subject to its jurisdiction," the Commission finds that an investigation should be initiated to review the financial condition of East Kentucky Power.*

In November 2006, EKPC gave notice of its intention to file a rate case seeking $50-60 million in rate relief and announced the impending retirement of its CEO. EKPC named a new, interim CEO in December 2006. That same month, Warren Rural Electric Cooperative cancelled plans to become a member owner of EKPC. The Commission responded with an investigation of the adequacy of EKPC's generating capacity (Case No. 2006-00564).

EKPC did make its planned rate filing in January 2007 (Case No. 2006-00472), seeking $43.3 million in additional revenues. The filing also demonstrated the seriousness of EKPC's financial situation by seeking emergency rate relief and by noting the deferral of already past-due maintenance on Spurlock #2 and Dale #3. Further demonstrating EKPC's financial situation was the testimony of a CFC executive that EKPC would not qualify for an investment grade credit rating. The Commission granted EKPC $19 million in interim rate relief on April 1, 2007, stating:

> *As a general matter, prudently managed utilities will not willingly place themselves in a position where interim rate relief during the suspension period is necessary to avoid a material impairment of the utility's credit or operations. This is especially true of rural electric cooperative corporations. KRS 278.095 provides that a cooperative "shall be operated on a nonprofit basis for the mutual benefit of its members and patrons." While low rates are desirable, this must be balanced against the necessity that a cooperative remain financially and operationally viable. With the shadow of Big Rivers Electric Corporation's bankruptcy only recently receding in the memory of Kentucky utility jurisprudence, all directors and officers of jurisdictional utilities should take note that the extraordinary relief authorized under KRS 278.190(2) is just that – extraordinary.*

Meanwhile, the investigation of EKPC's plan to construct additional generating units in light of Warren RECC's cancellation continued. EKPC would later (in May 2007) surrender the Commission-granted CPCN for Smith CTs #10 - #12. The Commission determined that the remaining generation additions should proceed.

Shortly after replacing his predecessor, the new, interim EKPC CEO commissioned a study of management and governance by the National Consulting Group, a business unit of the National Rural Electric Cooperative Association. The April 2007 report of this NRECA unit (NCG) was critical of executive management and the board. The interim CEO provided the NRECA report to board leadership, but did not share the report with the rest of EKPC's board.

Later in the year (June 2007), the Commission closed out the financial investigation, given the continuing nature of the rate proceeding. The Commission eventually awarded EKPC $19.0 million in permanent rate relief in December 2007. The Commission did not award EKPC any rate relief beyond the initial interim $19 million, finding that the cooperative did not meet its burden of proof to justify additional funds.

By September 2008, EKPC's summary of expected, five-year needs and financing underscored the growing significance of its financial stress. Estimates of total capital needs across this period had reached $1.5 billion: $900 million for the new Smith Unit #1, $300 million for the Cooper scrubber, $100 million for various transmission projects, and $200 million for miscellaneous projects. EKPC stated that it planned to secure the $900 million for Smith from private (*i.e.*, non-RUS supported) markets (the RUS moratorium on financing baseload plants was in existence), and that it had drawn $615 million against its $650 million CFC-syndicated credit facility.

In October 2008, EKPC filed an application to establish a regulatory asset for forced outage costs incurred during the first part of 2008 (Case No. 2008-00436). In a 2-1 decision, the Commission authorized establishment of the regulatory asset, but only after noting that:

> *Without the establishment of a regulatory asset for purchased power costs arising from forced outages, East Kentucky's financial viability is questionable. We find that East Kentucky's request to establish a regulatory asset to account for non-FAC-recoverable purchased power costs arising from forced outages is for a lawful purpose and reasonable in light of its precarious financial condition. This will afford East Kentucky more time to resolve its long-term financial problems.*

The Commission was unanimous, however, in finding that a management audit of EKPC was necessary, stating:

> *It is altogether unclear that East Kentucky has, as of yet, arrested the deterioration of its financial condition. That question will be thoroughly addressed in the context of East Kentucky's pending general rate case. The larger question is whether East Kentucky is fully committed to reversing its weakening financial condition. Ultimately, the responsibility for East Kentucky's*

> *viability lies firmly within the province of its board of directors, who have a fiduciary duty to safeguard the financial and operational viability of the cooperative. The Commission cannot and should not usurp the directors' duty to make business judgments, but as the statutorily created regulatory authority, it also cannot and should not turn a blind eye to a situation which does not appear to be getting better.*

Three weeks after filing its application to establish a regulatory asset, EKPC filed an application to increase its base rates by $67.9 million and to establish a regulatory asset for the amount of rate relief lost due to a delay in filing the application. EKPC followed these filings with a November CPCN application (Case No. 2008-000472) for Cooper #2 Scrubber and SCR projects estimated to cost $324 million (granted in May 2009). On March 31, 2009, EKPC received $59.5 million (87.6%) of the $67.9 million in rate relief it had requested. In April 2009, Spurlock #4 went into commercial operation. In June 2009, the interim CEO was replaced by his new, permanent successor.

Credit issues have existed at EKPC throughout this period. Since September 2005, EKPC has obtained unsecured, short-term financing through a private credit facility arranged through CFC, a not-for-profit entity owned by rural electric cooperatives across the country. EKPC has obtained long-term financing through RUS, secured by a mortgage on its properties. EKPC's long-term debt totaled over $2.4 billion at the end of 2008. EKPC's financial difficulties resulted in a technical default on its RUS debt at the end of 2006.

An extended period of time transpired between the preparation of the November 2009 draft of this report and the receipt in February 2010 of EKPC's comments on its factual accuracy. Those comments stated that, as of December 31, 2009, EKPC has procured financing for all of these facilities, and needs Commission approval of its pending Smith financing request before the Commission to complete its funding of ongoing projects. EKPC also reported that it has paid down its Credit Facility to $325,000,000.

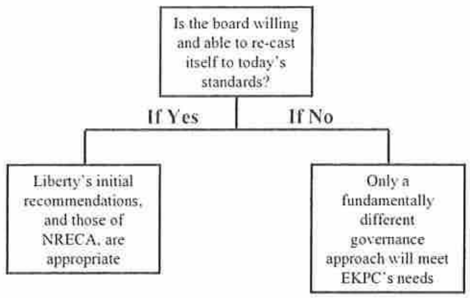
C. Near-Term Challenges Imposed by the Smith Plant

Smith continues to present major challenges for EKPC from a financial, cost, regulatory, and litigation perspectives. LG&E and KU, for example, serve over 915,000 Kentucky customers, as compared with the 511,000 served by EKPC's members. According to the most recent available staff reports, EKPC, despite serving a base that is about 55 percent of the customers served by LG&E and KU, plans to make capacity additions (in the range of 1,500 MW) that are roughly equal to those of LG&E and KU through 2020. This proportionately much greater level of construction may put significantly greater pressure on the gap that already exists between EKPC rates and those of neighboring suppliers against whom it must compete for new load and against whom members can compare price performance.

The cost estimate for the 278 MW Smith project was $533 million in mid-2006; it has grown by 54 percent to a current estimate of $819 million. EKPC is currently seeking Commission approval of an even higher amount ($921 million), citing uncertainties affecting the current estimate. Those uncertainties remain substantial, including:

Recommendations

- Liberty has developed specific preliminary recommendations
- We have shared with you a draft of them
- A major question needs answering to move them along:



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Recommendations

Under the "Yes" scenario (*i.e.*, no <u>inherent</u> conflict)

- ✓ Redefine the role of the board and expectations for its performance
- ✓ Elevate the priority of financial strength and the board's sensitivity to it
- ✓ Deal with the conflict issue
- ✓ Focus on strategic planning and the setting of policy
- ✓ Upgrade the performance of directors
  - ❑ Minimum requirements and expectations
  - ❑ Continuous education and training
- ✓ Upgrade the commitment of directors
- ✓ Conduct meaningful self-evaluations of board performance
- ✓ Upgrade the Audit Committee and implement an internal audit function
- ✓ Fix the committees
  - ❑ Required mission versus vague options
  - ❑ Define clear objectives
  - ❑ Committee sets agenda
  - ❑ Increase level of commitment
- ✓ Implement an issues management program assuring recommendations are not ignored
- ✓ Increase external support for the board
- ✓ Require options from management
- ✓ Bring risk analysis and risk management into the decision-making process
- ✓ Challenge RUS administrative requirements that unnecessarily tie up the board
- ✓ Implement a whistle-blower policy allowing access to the board
- ✓ Implement recommended fraud deterrent programs

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C. Liberty's Initial Recommendations

The following recommendations reflect what Liberty was prepared to recommend last November, under the assumptions that: (a) management was in general accord with the conclusions summarized above and (b) the board accepted the need for fundamental change. As this report will describe later, the dialogue that has taken place with EKPC since that time no longer allows us to place substantial confidence in the ability of these recommendations to make needed changes at EKPC (in either management or the board) on a basis that is commensurate with the needs that the enterprise faces. Liberty presents them here to establish with more specificity the kinds of changes contemplated by the summary information shown above.

1. November-Vintage Recommendations – Management

1. **Develop and implement strategic plans that address the company's critical existing and forward-looking issues: asset mix and ownership, the optimum power supply portfolio including market power supply resources, appropriate financial strength and capital market access, and rate trajectory and competitive issues.** *(Conclusions 1 and 2, Strategy)*

The NorthStar initiative was the highest priority "plan" that emerged from the 2007 MCR strategy process. Management (and the Board's) strategic focus should be on more critical core directional issues, such as the ownership (or sale) of assets, EKPC's financial health and performance, the lack of access to power markets and unbalanced power supply portfolio, and the rate impact of its huge capital program.

EKPC must address the question of "where it is going" with respect to these core strategic areas, which have not been sufficiently addressed individually and holistically so far. The focus of any future strategic planning processes must directly address and evaluate these key issues, and form clear and measurable action plans.

2. **Make the attainment of strategic goals its top priority, with effective upper management follow-through, strategic plan updating and Board monitoring.** *(Conclusion 3, 4, and 5, Strategy)*

The MCR process succeeded in defining some of the most important issues facing EKPC and it spotlighted a number of weaknesses or gaps that exist in EKPC's ability to address those issues effectively. However, EKPC has completed only a portion of the strategies and action plans that were established by the strategic planning process. Management has not put a sufficient priority on "making the plan happen."

A focus on developing and executing action plans and making them top priorities remains critical. The strategic plans should also regularly be updated, action plans should be established to address revised strategies, accountability for executing plans be clear and enforced, progress should be tracked, and that there be a process for continually re-evaluating strategies and plans in light of continuing change in the power supply business. EKPC needs to begin to view strategic planning as a continuous exercise, and to create a culture and to adopt methods that will allow it to act in ways that permit adjustments to be made.

EKPC did not follow up or take significant action on the recommendations of either the Byrne report or the NCG report, effectively burying them. Management must be held more accountable for effectively making changes recommended by external entities that the Board and management agree are important to strengthening EKPC operations, performance and rate competiveness.

3. **Adopt Board capital structure and financial performance targets that ensure financial strength and access to capital markets.** *(Conclusions 1 and 3, Finance)*

EKPC's too-aggressive approach to financial management has historically produced low levels of debt coverage, equity capital levels, and cushion to protect the company if unexpected financial challenges arise. Managing to such thin margins was designed to keep member rates at minimum levels for the short run, but did so at the expense of building the financial strength and viability necessary to address unexpected financial incidents. This strength is required to optimizing rates over the long term, particularly as contingencies occur. However, EKPC steadfastly refused to set equity level targets that support adequate financial strength.

EKPC management should immediately evaluate and establish optimal equity level target and credit rating goals that plan for an end to the company's "boom and bust" cycles. Equity levels should be increased to 20 percent or more to establish the more adequate equity levels maintained by most other G&T companies that provide increased protection and attractiveness to capital markets.

Outage insurance is a tool that can form part of a sound financial portfolio by mitigating the risk of one of a power supplier's major contingencies. While such outage insurance is expensive, EKPC should have such coverage until its equity capital reaches much higher levels. Its reliance on what it believes others do is misplaced in failing to consider that what others do is a function of financial conditions that do not apply at EKPC. The technical defaults on RUS debt in 2006 demonstrate the lack of financial strength necessary to weather major contingencies, such as generation outages, with its thin capital structure.

4. **Define the levels and trajectory of future rates with its planned capital expenditures, power portfolio and appropriate financial targets, and report the results to the Commission.** *(Conclusions 2, 3, and 4 Finance*)

EKPC's rates have grown to levels that are a burden to its members and far out of line with neighboring utility Kentucky Utilities. High capital expenditures have contributed and may significantly contribute to this phenomenon. However, EKPC and its board do not have an adequate grasp of the reasons for its high rate levels, especially in comparison to neighboring utilities. The cooperative must determine the specific quantitative reasons for its current rate levels and provide explanations for key differences with neighboring utilities.

EKPC should also provide a projection of its future rate levels at the wholesale and distribution levels, including its planned capital program and operations. An analysis of the economic impact of the projected rate increases should also be conducted. The analyses should be immediately prepared for review by the Commission.

5. **Obtain independent analysis and recommendations for financing alternatives such as sale/leasebacks to more effectively fund capital expenditures and reach capital structure targets.** (*Conclusion 4, Finance)*

The RUS moratorium on providing financing for base load generation will require a different approach to financial management for EKPC. While EKPC has been exploring private capital markets, it has not adequately investigated or implemented alternative means of financing its asset base and requirements. EKPC has inappropriately dismissed alternatives such as sale-leasebacks or asset sales as not being viable, without performing the comprehensive and unbiased analysis that should underlie such decisions.

EKPC should have independent market experts provide analysis of various financing techniques and present them to both the company and the Commission.

6. Greatly improve capital budget performance and Board understanding and monitoring of such spending and resulting rate levels. *(Conclusion 5, Finance)*

EKPC has under-spent its approved capital budget by 34 to 50 percent in each of the last four years, indicating deficiencies in both capital planning and in management accountability for budget variances. Such huge variances also denote deficiencies in the Board's capital budget oversight, one of its most important responsibilities.

EKPC should immediately make capital budget performance the most important measure affecting the compensation of the CFO and all managers with budget responsibility. The entire capital budget process should be evaluated and restructured as soon as possible to improve this crucial performance area.

7. Replace the NorthStar initiative with effective operating expense budgeting plans and oversight linked to manager's performance evaluations. *(Conclusion 7, Finance)*

EKPC's performance to the NorthStar plan was inadequate through mid-2009, indicating performance problems with operating expense budgets that are similar to those of the capital budget. EKPC should make operating budget performance an important measure affecting the compensation of the CEO, CFO, and all managers with budget responsibility. The entire expense budget process should be evaluated and restructured as soon as possible to improve performance in this area.

8. Hire an *independent consultant* to determine EKPC's optimal power supply portfolio, considering the possible sale of existing assets and more extensive use of purchased power. *(Conclusion 1, Power Supply)*

EKPC has provided power supply for its members under an approach that far overfocuses on building, owning, and operating generation resources. EKPC has not adequately pursued longer-term power contracts. This strategy has become significantly more risky in recent years; it requires immediate re-evaluation.

EKPC should hire independent experts to assist in determining an optimal power supply portfolio that may contain a mix of owned generation assets with different fuel supplies as well as purchased power contracts and spot market purchases. The optimal portfolio would consider load requirements, owned generating assets, ownership options, markets and supply sources, renewable energy requirements, and transmission capabilities. In contrast with how EKPC has approached integrated resource planning, an optimum portfolio would consider options related to changing the company's existing asset base through beneficial sales or ownership options. Independence criteria should preclude reliance upon entities with which EKPC has had long and close relationship in enabling its current approach to funding supply assets and its market alternatives.

The independent consultant should provide its report and conclusions to both EKPC and the Commission.

9. Obtain an independent evaluation of the market value of EKPC's major assets. Diversify the existing EKPC power supply portfolio by evaluating and pursuing economically favorable transactions. *(Conclusions 2 and 3, Power Supply)*

EKPC has not adequately pursued partnerships, turn-key construction contracts, asset sales or other alternatives to the self-build and own option for Smith #1. Good business practice requires executives of all entities, especially capital-intensive power suppliers, to know the approximate value of each of their major facilities or asset classes. Management should also know if assets may be more advantageously utilized by specific outside parties, making them more valuable to others.

EKPC should engage independent advisors to determine the market value of its major assets (including the Smith 1 site) and the economics of the potential sale of such assets. The independent consultant should provide its report, analysis and recommendations to both the company and the Commission. EKPC should pursue transactions that provide net economic benefits and improve the company's capital structure or financial strength. Again, independence precludes the use of those with whom EKPC has worked in close business or advisory relationships in the past.

10. Determine whether investments in the transmission system to improve access to power supply alternatives are economically justified. *(Conclusion 5, Power Supply)*

The inability to effectively transfer power with its neighbors or regional markets causes higher fuel and power supply costs. However, EKPC has not yet analyzed the alternative of investing in and strengthening the transmission system specifically to allow for additional purchased power or exchanges as power supply resources. EKPC's efforts to strengthen its transmission system have focused on reliability, without appropriately considering power supply economy. EKPC should immediately evaluate the economic impacts of such targeted transmission investments and report the results to the Commission.

11. Hire independent market experts to evaluate the costs and benefits of joining an ISO. *(Conclusions 6 and 7, Power Supply)*

Greater market access would allow EKPC to pursue joint dispatch opportunities with surrounding utilities, expand reserve capacity, develop seasonal and load diversity exchanges and increase its surplus power sales and increase its margins.

The benefits of greater access to neighbors and markets may be enhanced if EKPC joins either the MISO or PJM ISO. EKPC should hire an independent consultant to determine the costs and benefits of ISO membership. The independent consultant should provide its report and recommendations to both the company and the Commission. Again, independence precludes the use of those with whom EKPC has worked in close business or advisory relationships in the past.

12. Conduct an immediate and comprehensive assessment of senior executive management's ability to chart an appropriate future course for EKPC. *(Management and Governance Conclusions generally)*

Management has for years been given input that should allow it to understand the needs for change that confront EKPC. That change involves not only approaches, values, and techniques. It has also included candid assessments of senior managers.

EKPC has declined many "invitations" to undertake changes like those identified in the preceding recommendations. Even now, its basic approach to key issues involving power supply and finance, for example, is to bring in new consultants. Moreover, they are consultants who have already been unsuccessful in getting EKPC to change its viewpoints and approaches, and in some cases its management. Either senior management responsible for these areas continues to be a barrier to change, or lacks the ability to overcome barriers imposed by the board. Whatever the reasons, management's inability to offer more than another round of consultant study reinforces the conclusion that EKPC needs not only to examine the issues it faces, but also to examine those who have not brought change and still have either no empowerment to make change or, alternatively, a clear sense of where it is needed.

It is true that the CEO, who bears (or should) direct responsibility for power supply and financial matters has been at EKPC for less than a year. He certainly came to EKPC in the middle of 2009 expressing a commitment to change and declaring himself its leader. Recent actions and Liberty interactions with management and the board, however, do not give confidence that he continues to be a true champion of change. Whether this is because he does not have the board to do so is not clear.

Whether the inability to create more momentum for change is a function of management's approach to the challenges or how board leadership has allowed management to approach them is fast losing consequence. Whatever the source of the barriers, EKPC cannot long continue on its current course. Therefore, the required assessment of management should exclude no senior executive responsible for power supply and financial matters.

2. *November-Vintage Recommendations - Governance*

1. Develop and subscribe to a set of governance standards consistent with modern practice and the needs of the power supply cooperative. *(Conclusion 1)*

EKPC has many options here, including starting with the minimal standards suggested by Liberty; retention of a consultant to develop a more definitive set of standards; or perhaps working with others in the cooperative community, including NRECA, to develop a more generally applicable set of standards. The key is that any standards should be consistent with the new demands for oversight and transparency that have emerged in recent years.

2. Complete a formal analysis, incorporating Liberty and NRECA governance observations, of the degree of compliance with the new standards developed above in Recommendation #1 and including a program for achieving compliance. *(Conclusion 2)*

The recommended analysis is intended to define gaps that EKPC needs to fill, including those already identified by Liberty and NRECA. Presumably, many of the recommendations that follow in this report will also be appropriate for this analysis.

3. Redefine the role of the board and expectations for its performance. *(Conclusion 2)*

Many of the conclusions in this report relate to the fundamental role of the board and expectations for the performance of individual directors and the board as a whole. A key element of reforming governance at EKPC must therefore be a reexamination of the board's role in the business of EKPC.

4. **Elevate the priority of strategic planning as a board function and become heavily involved in providing strategic direction to management.** *(Conclusion 3)*

The MCR effort brought a sound beginning to the kind of strategic thinking that the board should embrace on a continuing basis. But it is clear that the initial work was not sustained at the board level, and most board members remain unaware of its conclusions and subsequent results. The board needs to do far more in both formulation of strategies as well as implementation and continuous testing and monitoring of strategies.

Reports against a strategic baseline should be provided regularly, and to some extent they already are. But they are clearly ineffective at the board level. Formulation of plans needs to be a periodic board task and status of implementation needs to be a monthly topic. Further, these tasks need to be discussed at length, and not just dismissed with the issuance of a management report.

5. **Elevate the priority of EKPC's financial health and the board's sensitivity to it.** *(Conclusion 4)*

The financial health of EKPC is not given sufficient attention by the board. Targets for TIER and equity should be established and managed, with the board exhibiting a long-term commitment and understanding of what constitutes adequate financial health. Again, the first part (targets) are to a large extent already in place. But the thinking behind those targets at the board level and an understanding of the adequacy of long-term targets is lacking.

6. **Reconcile the conflict of interest immediately in favor of EKPC.** *(Conclusions 5 and 6)*

Liberty has concluded that a de facto conflict does indeed exist and it is real, continuing and dangerous. The conflict forces a philosophy of low rates at the expense of all else and hence influences all of the board's actions in key areas, including financial health, rate strategies, and strategic planning. It manifests itself most directly in the balancing of financial health, as expressed in targets for TIER and equity, against the goal of lower rates.

Since this recommendation calls for a change in underlying philosophy, there is a tendency to see the required fixes as intangible, but that is not true. A fundamental change in thinking is necessary, but that must be accomplished along with numerous tangible actions.

The board must articulate a new, EKPC-centric way of thinking and acknowledge that, while the consumer's voice must be heard, a role of consumer advocate is not acceptable for directors. Further the board needs to commit to enforcing this notion on a continuing basis, with specific measures for the removal of directors who sacrifice EKPC's interests for others, including the interests of the distribution cooperatives.

Liberty acknowledges that this long-held philosophy may be too hard to break, and that directors may continue to feel compelled to function as "consumer advocates." In that case, the conflict is "inherent," and an alternate governance scheme is necessary.

7. Greatly expand knowledge and understanding of the "KU gap" and reevaluate its use of that parameter as a strategic imperative and "the NorthStar metric." (*Conclusion 5*)

Despite the prominent role of the "KU gap" in its strategies, EKPC does not have a firm grasp on the underlying reasons for the gap. Perhaps such knowledge is not necessary to gauge the consequences of the gap, but they surely are required to understand how to narrow the gap going forward.

Further, the ability to fully understand the gap will allow directors and management to put it in a proper perspective; *i.e.*, what gap makes sense given the realities behind KU's and EKPC's businesses.

8. Require a structured program of risk management, including identification and management of continuing business risks and expansion of economic evaluation practices to incorporate risk. *(Conclusions 8 and 9)*

9. Greatly expand audit committee activities to be more compatible with modern audit committee duties and commitments. *(Conclusions 10, 11 and 12)*

Expanded efforts should include (a) more frequent meetings; (b) expanded risk capabilities; (c) implementation of its risk duties as defined in its charter and as may be modified by Recommendation #8 above; (d) implementation of an internal audit program; (e) greater focus on internal controls; (f) review of lessons learned from other cooperatives; (g) development and implementation of a whistle-blower policy; and (h) implementation of the fraud deterrent programs suggested by Crowe Chizek.

10. Increase oversight of management, its expectations for management performance and its requirements for management reporting and analysis. *(Conclusion 13)*

It is the role of the board to provide guidance, direction and oversight and not, as suggested by some, merely to ratify the CEO's desires. A good start here would be for the board to require options from management, rather than a singular "take it or leave it" solution. This should of course be accompanied by positive discussion of the options such that the board has a thorough knowledge of the possible outcomes and can make a decision with a strong foundation.

A second improvement would be a requirement that management provide analysis in addition to "numbers." Charts and graphs showing traditional measures may be interesting, but they give the board no insight. The addition of management analysis, highlighting areas of concern and, especially, discussing corrective measures for non-performing areas, will help the board meet its oversight responsibilities.

The role of the board in the management of board and committee meetings should also be expanded. Directors should insist on substantive input to agendas, including the topics and the amount of discussion expected. The present near-total reliance on management is not appropriate.

As a final note, we previously discussed the tone of Policy No. 104 as seeming to be designed to keep the board in its place. This policy should be reviewed and revised as appropriate to define a tone more consistent with an active, involved board.

11. Implement an issues management program. *(Conclusion 14)*

The board's prior failures to deal with important issues brought to its attention suggest the need for a more formal and structured vehicle for tracking and managing issues. As a minimum, an "open issues" list should be maintained and reviewed monthly. This should define all issues brought to the board for action, the plan for closeout and the current status. Items should not be removed from the list without the board's formal approval.

12. Periodically conduct a meaningful self-assessment of board performance and needs. *(Conclusion 15)*

Although this is an existing requirement at EKPC, and an assessment was conducted in 2007, Liberty found the process to be ineffective. The assessment conducted was actually an opinion survey and no follow-up actions took place. An effective self-assessment will provide individual critiques of the board's performance and in particular where it needs improvement. An appropriate action plan, to be implemented by the board, is the final measure of success.

13. Adopt board responsibility to police itself. *(Conclusion 15)*

Liberty found that the board tends to take some of its weaknesses as givens and assumes it is powerless to deal with them. This is an unacceptable way of thinking in that the board has the final say at EKPC. If the board does not assure proper functioning, then the only resort is action by the customer-owners, and that is simply not practical. The board can and must be responsible for assuring its own performance.

14. Define qualifications required of its directors and assure that those qualifications are met initially and then sustained. *(Conclusion 16)*

Reasonable people can debate the nature of such qualifications, but it is not reasonable to have no qualifications defined at all. EKPC is a complex business, and its governance is a real challenge. Minimum standards should be set for the directors' qualifications including types of skills, experiences, level of commitment, ability to engage management and other directors, loyalty to EKPC, willingness to spend the required time and effort and other qualifications as deemed appropriate by the owners.

15. Create and use the ability to acquire external skills where the board lacks those necessary to provide experience and capability commensurate with the size, scope, and complexity of EKPC's business operations. *(Conclusion 16)*

Regardless of the qualifications eventually required of the directors, the need for added skills from time to time is likely. The board needs the flexibility to acquire such skills when and as needed to meet its governance obligations.

16. Redefine the board's expectations for committees, their roles and their commitment. *(Conclusion #17)*

Liberty has concluded that the committees fail on several levels to engage in the business of EKPC. The committees should be the front line contact with management, eliminating the need for an unacceptable level of detailed discussion at a 32 member board meeting. But the committees fail in this regard. The short duration of their meetings, their requirements for administrative resolutions and their failure to meet the responsibilities of their charters all serve to make their role ineffective.

It is presumed that the overall structure of committees will be modified as part of the changes in the board's role. It will be important to also transform the committees' roles. The current issue is not structure or scope, it is a failure to assume a meaningful role, and that is the primary problem to be solved regarding the committees.

As a further part of committee reform, the administrative chores required of the committees, including those supposedly imposed by RUS, should be reexamined.

17. Substantially increase the time commitment expected of directors. *(Conclusion 18)*

Liberty found that the length of time spent in board and committee meetings is far less than required of a business of this complexity. Directors must be able and willing to spend far more time on their responsibilities.

D. Changes in Liberty's Understanding of the Need for Change at EKPC

On January 21, 2010, EKPC leaders orally presented the approach to and principal components of their proposed action plan. In comments intended to assist EKPC in completing the formal documentation of its plan, Liberty advised that EKPC's plan was comprised principally of further study and did not reflect commitments to actions that should not be deferred pending such study. Liberty expressed the need for EKPC's formal documentation to:

- Provide a statement of specific management actions that would be taken without waiting the six to nine months required to complete "assessments"
- Consider carefully the fact that the consultants selected to assist EKPC had all been there before, and that one was being asked by EKPC in effect to examine objectively the alternatives for providing services that this consultant was currently providing
- Address the fact that EKPC's actions needed to have clear, designated executive responsibility, and to reflect board consensus
- Make clear that internal personnel had clear responsibility for leading improvement efforts, and that consultants could support, but should not lead the process.

EKPC expressed some level of agreement with Liberty's report, but carefully avoided directly addressing any of Liberty's findings. It eventually became apparent that, months after the board's November 4, 2009 direction, EKPC remained divided and undecided. An EKPC representative noted that "the board does not have a consensus on the Liberty findings."

On January 28, 2010, EKPC formally submitted its written, proposed action plan, without clear indications of response to Liberty's identification of needs. Liberty found the plans to be non-responsive to the identified conclusions and issues. It did not make firm commitments (beyond an analysis to determine if any changes were needed) to address the substantive issues. It demonstrated a very different sense from Liberty's about the severity of EKPC's current situation and fundamental concerns about its future prospects.

On February 8, 2010, EKPC formally submitted its comments to the Liberty report, in response to Liberty's request at the January 21 meeting to provide a clear and comprehensive statement of where EKPC agreed and disagreed with Liberty's statement of underlying needs. Liberty emphasized that such a clear statement was critical in order to allow a determination of whether the open-ended plans presented were at least being pursued with a common understanding of the gaps that needed to be closed.

The response ultimately provided by EKPC has not demonstrated the existence of the clear commitment to necessary change. Rather, it creates a very significant risk of continuing a "business as usual" approach. In essence, EKPC has proposed to undertake again what it has tried many times already; *i.e.*, to have outside consultants look at what weaknesses may exist and to recommend actions to address any that may be found. As our November-vintage recommendations indicate, study is not irrelevant. But the time has passed for study alone (and particularly study by outsiders) to be considered adequate. Prompt action is now the point. Moreover, a commitment by management and the board to an uncompromising, expedited, and self-directed program of action is essential. Instead, EKPC has proposed problem or needs assessments that themselves will take from six to nine months. Additionally, EKPC has done so under circumstances that do not reflect acceptance of the breadth, types, and depth of changes that Liberty considers to be necessary. Under EKPC's approach, one cannot know:

- What problems and needs EKPC will recognize after that time
- What actions it will propose to take
- How long it will take to accomplish them.

This uncertainty makes the EKPC approach unsatisfactory. It is rendered more problematic when one notes that the consultants named to take the lead on the management issues have worked on the same issues for EKPC in the past. It is more than optimistic to hope that a repeat of prior, consultant-led exercises will prove more beneficial than they have on repeated occasions in the past.

The January and February meetings and document exchanges demonstrated that there was actually not a significant level of agreement between EKPC and Liberty, despite the November 4, 2009 letter from the board and verbal assurances from management. Liberty has therefore determined that continuing to seek an EKPC-led creation of an agenda for change would not produce a workable plan and that Liberty's November-vintage recommendations were not likely to be effective either. EKPC's responses made clear that there remains considerable disagreement on the fundamental issues, both on the part of management and the board. Moreover, EKPC's proposed action plan, which consists of a management plan and a governance plan, did not respond substantially to Liberty's conclusions about change needs. It exhibits three gaps that Liberty finds substantial.

First, the management action plan comprises two programs: a process analysis and a risk assessment, each to be spread over nine months. One cannot argue with the value of either, but neither addresses directly the specific issues raised by Liberty. Neither offers reasonable prospects for timely and responsive change, considering the issues that EKPC faces. In the meantime, the many immediate solutions, identified by Liberty and EKPC's own consultants over the years, remain unaddressed by management. The conclusion that Liberty reached is that management is either unwilling or unable to take the actions necessary to remedy the needs that Liberty has identified.

Second, the governance response represents a "best practices" approach that, again, has merit for any organization seeking to optimize performance. However, it simply is not responsive to the major needs facing EKPC. Some of the recommendations have already been tried at EKPC and have failed; the action plan does not address that barrier. There is no acknowledgement, or even discussion, of prior failures and what will be different this time. The plan does discuss most (if not all in some form) of the categories of governance performance that Liberty's draft report addressed. However, it does so without describing what EKPC does, has done, or falls short in doing in a manner that responds to Liberty's conclusions. Instead it discusses those categories in largely terms of what others do.

Most importantly, Liberty's key question in the preliminary recommendations was "is the board willing and able to re-cast itself to today's standards?" The failure to identify what specifically will be changing at the board compels an answer of "no." Proceeding from any other premise cannot be expected to produce more than marginal change. EKPC's board needs fundamental change in its composition, membership requirements, and functioning.

Third, the responses reflect no sense of urgency by management or the board or recognition of the severity of EKPC's situation and the need for a thorough assessment of its direction. Instead, the response appears more designed to "buy time" and offers no reason to believe that EKPC anticipates a change from "business as usual" over time.

In summary, the February 8, 2010 response makes it clear that EKPC's position in response to Liberty's identification of needs forecloses an effective, EKPC-designed solution. Liberty concludes that the level of disagreement within EKPC management and the board precludes timely and effective response to the Liberty findings. Given the existing board and management team and the lack of acknowledgement of the need for major change and improvement, one should conclude that there is not a significant chance that improvement will come in a way that is either substantial or timely.

E. Specific Comments On EKPC's January and February Submissions

1. EKPC's Action Plan on Management Recommendations

Page 9 of the EKPC response discusses its "general reaction." This portion of the January 28, 2010 EKPC document contains a number of positive statements. They include an invitation for Commission Staff to sit in on occasional board meetings and classes. But there is no indication in the text that EKPC understands the severity of its current situation and the urgency required to deal with circumstances that already place it at a competitive rate disadvantage that has the clear potential for growing worse.

Any "general reaction" short of an awakening, a call to action, an acknowledgement of the severity of EKPC's problems and an aggressive commitment to doing what it takes to make corrections does not match the gravity of the situation. EKPC has stated in meetings that the report did serve as a "wake up call," but that general statement finds no support or confirmation, and (more importantly) amplification in the January 28, 2010 response. That response gives no indication of any sense of immediacy. To the contrary, EKPC has proposed a program that will require many months or years to achieve even intermediate goals. Liberty was struck by the incongruity between the verbal reactions that dialogue with EKPC had engendered and the greatly more muted tone of the written document.

EKPC's response to the management issues proposes too little ("assessments" of processes and risks) and too late (nine months to complete assessments, with no specification of the schedule for completing changes). This portion of the response confirms that EKPC fails to gauge the importance of the issues it faces. For example, the following needs fall among those that can and should be addressed without any delay.

First, the necessity for changes in certain key personnel was identified years ago (not initially by Liberty). The appropriateness of such moves continues to be apparent.

Second, EKPC's ability and willingness to optimize power supply costs through its interactions with the regional markets was questioned by both Liberty and prior consultants. EKPC's response is to retain a firm to perform an "independent" assessment. This firm is the very same firm that has helped craft the EKPC market strategy in the first place, and, perhaps most significantly, it stands to lose (as a vendor and an advisor) if certain changes from the status quo take place. EKPC was one of the initial founders of this cooperative marketing entity. Surprisingly, EKPC finds its long standing relationship with and support for this entity to enhance rather than diminish objectivity. EKPC also proposes to take an excessively long time (nine months) to reach a conclusion.

Third, Liberty has emphasized that the continued commitment to a build/own/operate approach, and the lack of robust consideration of ownership structuring and market-based alternatives to its next proposed new generation fails to recognize both the opportunities and risks of today's power supply and generation environment. In addition, EKPC's extremely high level of anticipated expenditures and the large rate disparity it already imposes on distribution cooperative member/customers raise real questions about the costs to ultimate users and about the ability to fund and carry through on its long-standing approach to meeting the needs of the ultimate users that it serves.

Nevertheless, EKPC proposes to continue pursuing Smith 1. During the nine months during which it will undertake "risk assessment," EKPC proposes to obtain approval of nearly a billion dollars in permanent financing for a project that may be the biggest risk it will face in many years. EKPC's failure to address this issue, other than as a part of a nine month risk assessment, is a major failing of the EKPC response. Moreover, EKPC has indicated that it is working with the CFC to address this issue. The EKPC board chairman is a director of the CFC and its audit committee's financial expert. The CFC is a cooperative-owned financing entity that has total gross loans and guarantees outstanding of $21.5 billion and its owners have invested more than

$4.3 billion in CFC securities. It too has close and long-standing relationships with EKPC. Relying solely on its support in this activity thus creates very substantial barriers in EKPC's candid examination or pursuit of alternative approaches.

Fourth, Liberty concluded that some critical areas were not being managed properly, with the capital budget and the NorthStar program goals given as two examples. It is not clear why management cannot address such problems immediately. The CEO has tasked the EKPC chief financial officer with addressing these issues since at least 2007.

The fundamental approach by EKPC to dealing with the audit's management findings is two-fold: (a) a process analysis and improvement initiative, and (b) a risk assessment and risk response strategy. Both approaches comprise good business practices, but EKPC has not linked them to the specific findings of the audit, and their ability to deal with the specific threats facing EKPC. Liberty found an absence of definition and specificity in EKPC's cursory descriptions of plans to address the audits' management findings and conclusions. This absence suggests a belief by management that examining the need for a more effective approach to general business management will serve as a "universal solution" to the sizeable list of gaps that Liberty believes to exist at EKPC. Liberty would not agree with such a view. We do not consider the proposed process analysis and risk assessment to be the solution to all of the management and business needs identified. EKPC's failure to propose a more focused confronting of the key issues it faces and the very general and summary-level treatment of the issue is troubling.

EKPC was presented in mid-2009 with a new opportunity in the form of a new CEO. A new CEO can offer a fresh new outlook and an aggressive and visionary plan for the future. A leader new on the scene often brings the advantage of an enhanced ability to see the problems and a license to fix them. In this context, the CEO's selection of consultants for the management issues is questionable. Liberty intends no criticism about the technical capabilities of the consultants. The concern that does exist (apart from difficulties they will face in assuring objectivity) is that they have already addressed similar issues for EKPC under prior top leadership.

Liberty therefore believes that EKPC's response to the management issues identified:

- Does not present a sufficient plan to deal with the issues identified by Liberty and those issues on which EKPC's future success rests
- Establishes that EKPC management and the board do not understand or accept the gravity of the current situation and the need for immediate and effective response
- Relies inappropriately on two general, long-term programs (process analysis and risk assessment) as effective means for dealing with the challenges that confront EKPC
- Presumes that critical regulatory approvals (such as Smith financing and a likely rate filing) should be permitted to take place before EKPC deals directly with the serious and immediate issues it faces.

2. EKPC Action Plan on Governance Recommendations

EKPC, through its governance consultant NCG, has advanced a learned approach to governance optimization. The presentation in the EKPC response lays out strong governance principles and best practices, as well as good ideas for how to move towards those objectives. In many ways, it represents a well prepared academic justification for adopting its principles and strategies. It however begs the question of "justification to whom?"

The EKPC board appears to be the audience for NCG's efforts at justification. The troubling aspect of that observation is why the EKPC board requires persuasion that the principles offered are appropriate for its adoption. There exist serious concerns not only about the board's willingness, but also its capability to do the things recommended first by Liberty, and then, as structured by NCG.

An overarching concern with the recommendations is the document's implicit premise that improving performance on top of a sound foundation is the goal. The need is more profound than that; establishing a sound baseline of capability and performance are first necessary. Starting from the premise that the baseline already exists will make it exceedingly difficult, if not impossible, to accomplish real EKPC governance change within a reasonable time frame.

Moving to the document's specific contents, the Governance section of EKPC's proposed action plan begins with the voice of "EKPC Leadership," defined as the executive management team and the 32 directors and alternates. But to assume that this is one voice does not comport with the observations Liberty formed after meetings with essentially all of them. As recently as January 21, 2010 (which follows at least the draft of the document by NCG), it was reported that the board did not have a consensus on the Liberty findings. A major concern developed through our audit work has been the degree to which "the board" means a very small circle of board leaders or the 32 directors and alternates as a whole. That important information has been withheld from the board as a whole in the past forms part of the concern about assuming that there is a substantially greater consensus around the NCG principles than there is around Liberty's identification of key governance gaps.

The Governance section includes numerous observations and recommendations that have been made or tried before at EKPC, but have failed. The document does not address this important perspective, and thus omits a key feature required to instill confidence in its ability to succeed this time; *i.e.*, what makes this occasion different from prior ones.

It is observed that NCG "has been impressed with the level of engagement of the EKPC board." This statement stands in stark contrast to Liberty's conclusion, supported by others, that "the board is not sufficiently engaged." It is not realistic to believe that such a fundamental change has taken place so quickly, particularly when board leadership cannot respond to the board's views on Liberty's key conclusions, because the board has not reached a consensus on them. In short, proceeding from the premises of board commitment and engagement appears to embed an optimism that is not consistent with a long pattern of performance and therefore does not appear designed to overcome serious obstacles that have existed for a long time.

A similar "disconnect" with experience arises in the case of strategic planning. The response indicates that board strategic planning retreats will be held. Such an approach has already been tried, without producing lasting impact, board understanding of its specific elements and initiatives, and structured tracking of performance. In fact, the prior retreat was held at the recommendation of NCG. With only two years passed since the prior retreat, few directors or alternates remember any of the outcomes of the retreat, nor do they know what, if any, strategic plans had resulted or what the status of those plans is at this time. EKPC now proposes to repeat the process with the same board members, the same management team (other than the CEO) and the same consultant. There is no acknowledgement of the failure of the same effort in the past and there is no discussion of what can and will be done to assure different results this time.

The EKPC response indicates that a Governance Committee will be formed, and that the committee will be charged with overseeing the implementation of the proposed action plan. In the abstract, such a committee makes sense, but a bare recommendation to create one ignores a fundamental barrier to its success at EKPC. Liberty concluded, as have others, that the committee approach at EKPC has not been effective. There are numerous examples of committee failures to follow charters, to exercise duties, and to spend the time needed to conduct their business. Within this context, placing oversight responsibility for this program with a board committee, without fixing the underlying problems that have made committees ineffective at EKPC, cannot be considered sufficient.

The EKPC response discusses a "perceived lack of transparency and trust between the board and past management" and further claims that this may have "led to many of the issues identified in the Liberty report." Liberty disagrees that such transparency lies at the heart of the issues found during the audit, and considers a focus on transparency to be unconnected with producing material change in either management or governance at EKPC. Liberty did observe one glaring example of important information that was deliberately withheld from the board by management; and that is the NCG report. Liberty reported that such behavior on the part of management did not appear to be customary at EKPC. At this point it is probably more important to consider the degree to which some board members, but not all, had access to the report. This is a board issue, not a management transparency issue.

EKPC's response confronts a primary issue, conflict of interest, directly. It provides both sides of the story and appropriately makes clear the writer's opinion of the right answer. A training session, presumably centered on that "right answer," is proposed as the corrective action. The seriousness of this issue, however, calls for significantly more. First, an expression of NCG's opinion is not ultimately the point. The real concern is what the board's decision is on the answer. Board consensus on that answer should already exist; if it does, the document does not address it. The response discusses the "intuitive view of many G&T directors" (not necessarily EKPC directors) that their primary obligation is to their distribution cooperative and, although not stated, it is clear that many EKPC directors are in that camp. Based on our interviews, and the "party line" established at that time, there is a deeper belief that the conflict issue does not even exist and what's best for the cooperatives is best for EKPC, and vice versa.

This issue was identified by the Commission and included in the audit RFP as a specific area of audit inquiry. It appears that EKPC's board has not yet dealt with this issue, that internal debates remain to be held sometime in the future, and that a "training" vehicle will serve as their forum. Accordingly, a major concern about governance will remain in place indefinitely and its only avenue for success appears to be optimism that discussion and training among directors who have not "come around" so far will be sufficient. In this light, it is difficult to see how the EKPC response can be considered adequate.

The EKPC response on the Board and CEO relationship is important. With the current condition of EKPC, leadership that is aggressive and visionary is essential. It is clear that, over the last few months, the dynamics at EKPC have constrained the new CEO from reaching his previously stated goals. Specifically, the uncertainties added by this audit, the struggles of board leadership to establish an effective role, the mixed reactions of directors, and a defensiveness on the part of managers to change direction all have served to restrict the CEO. The person holding this position needs to be given the opportunity, freedom, organizational support and board mandate to establish a vision with board concurrence and drive that change. He then needs to demonstrate the vision and leadership to carry out that mandate. Neither of these has happened. The sense of energy and optimism that characterized his approach last summer is not evident now, presumably because of the constraints noted above.

Liberty therefore concludes that EKPC's response to Liberty's governance findings:

- Provides academically and technically strong content, but does not respond to the particular challenges at EKPC, which go well beyond the need to make marginal improvements.
- Provides no evidence of any real change in thinking on the part of board members, particularly given the board's lack of consensus on the real issues.

On November 2, 2009, Liberty posed the question to the assembled directors and alternates: *Is the board willing and able to re-cast itself to today's standards?* Over four months later, EKPC has not demonstrated a positive, convincing response to the question. Liberty concludes that, at this time, the board is neither willing nor able to make the necessary changes.

F. Revisiting the Audit's Conclusions

The changed audit process, seeking an action plan initiated by EKPC, did not produce the hoped-for benefits. It did, however, serve to underscore the significance and the immediacy of the changes that will be required to place EKPC on a path that will produce sufficient optimism about its ability to meet the future challenges of those who rely most on its success; *i.e.*, the half million Kentucky homes, farms, businesses and industries served by EKPC's owners. It also has made clear the intractability of barriers to change at EKPC. New management leadership has not succeeded in its first eight months in bringing an attitude that embraces change across the organization. There is no perceptible entity-wide commitment to change that is more than cosmetic. The looming question of authorizing a nearly $1 billion commitment to the Smith project adds to the need for EKPC not to delay fundamental change. Deferring actions that EKPC needs to take until after that commitment is made creates the very real and disturbing potential for greatly diminishing the effectiveness of subsequent change, even if it proves real.

Starting from the audit work leading up to the November 16, 2009 draft report and ending with the subsequent dialogue between Liberty and EKPC, Liberty has arrived at the following foundation for crafting its recommendations for addressing the conclusions of this audit:

- Serious gaps and weaknesses exist at EKPC, and have gone unaddressed for a number of years
- EKPC has been afflicted with a conflict of interest that its board has not been successful in overcoming and is not on a path to overcome in a timely manner

- Neither the board nor management has been willing to accept repeated assessments of the forces and factors underlying serious issues that it has faced for some time and continues to face
- The result is that EKPC has not shown the willingness or the understanding it takes to deal with them effectively
- Liberty does not have confidence that its findings and conclusions have changed EKPC's thinking substantially, other than to have produced a willingness to look at changes that will not have effect (if ever) until after current and expected regulatory proceedings critical to EKPC have run their course
- Liberty's assessment of the current board and management team leads us to conclude that substantive change in any meaningful form is unlikely
- In the meantime, the substantial premium that customers pay to take service from EKPC remains and is at risk of growing further
- The pendency of a $921 million authorization for Smith 1-related borrowing and the likelihood of looming rate increase requests create an undue risk that opportunities for change delayed will be opportunities irretrievably lost.

Liberty thus ultimately found that the EKPC board has not been able as a group to deal effectively with conflicts of interest in how EKPC is governed and managed. Liberty has also concluded that present governance and management do not make it likely that EKPC will succeed in doing so in a timely and satisfactory manner. We commend the NCG commitment to helping EKPC implement new governance standards and behaviors. However, the contemplated effort, in taking years to complete, just does not promise a response that is commensurate with the needs that exist and the urgency in addressing them.

The concern about leadership here is not a matter of theoretical governance standards or abstract notions about public versus private organizational "models." EKPC acknowledges that its rates act as a major force in the economic health of eighty-seven Kentucky counties. EKPC's need to find a way to govern and manage itself much better ultimately involves fundamental questions of economic development, job retention and the region's competitiveness with others. EKPC has higher electric rates and lower equity than other regulated electric utilities in Kentucky. It proposes to accumulate perhaps $4 billion dollars or more in debt within just a few years. That debt threatens further decreases in EKPC's equity or (and perhaps and) multiple, significant rate increases.

It is difficult to be more specific than this about how and how well EKPC will prove able to manage sizeable debt increases in a way that makes the costs of the critical services it provides rates a sail and not an anchor for the communities affected. This difficulty arises from more than the direct concerns this report raises about governance and management. It is magnified by EKPC's: (a) lack of analyses or forecasts of its revenue requirements path, and (b) absence of a studied perspective on what continued escalation of its costs will mean for the economies it wants to and believes it can continue to help drive in the coming years. The absence of such information and analysis significantly compounds our concerns about relying on a change program that focuses principally on problem study, and sets a schedule that reflects no sense of urgency.

At the present time, all Americans face a future that presents fewer "certainties," other than the understanding that difficult choices lie ahead. Kentuckians in the communities EKPC serves are no different, but should understand that meeting energy needs economically is especially critical, given the states' resources, opportunities, and risks. Meeting energy needs economically has been an important element in making the state strong. It is likely to be all the more so in the future. Liberty has worked hard to convince EKPC board and management of the need for change. We do not believe that we have succeeded.

In any event, it falls to the 16 distribution cooperatives that own EKPC and in turn the half million member/customers who speak through those 16 to take ultimate responsibility for what role EKPC should continue to play, how it should play it, who should govern it and how it needs to be managed. As managers and directors of public enterprises often describe, when the customer is your owner, it isn't hard to figure out who ultimately wins and loses.

G. Addressing Change at a More Fundamental Level

The stakeholders of EKPC, including the distribution cooperatives, their member/customers and the Commission, find themselves today at a critical crossroads. The board and management have selected a path that essentially will "stay the course," including major new commitments for generation. It is difficult to envision how that course can be demonstrated to benefit customers in the long-term. In fact, it may well generate an increasing penalty in the form of further diminished rate competitiveness. EKPC has not focused on this issue analytically.

Liberty believes that the time has come for a candid and prompt reappraisal of EKPC's mission and future (beginning with a fresh look at its reasons for existence, the value it adds when compared to alternatives, and, as appropriate, its nature and roles). That reappraisal needs to be mediated by sources outside current management and the board, which not only have confined their mission to an examination of the need for change, but appear to be doing so in a way that will not challenge all that merits testing at the enterprise.

The distribution cooperatives, in their role as stewards for their customer-owners, should take the initiative now to change direction. The new path should start with a fundamental testing of the mission of EKPC, the outlook for the member/customers it serves, and other alternatives for meeting the needs of ultimate users. What that process will produce Liberty does not presuppose, but we do believe that, to be successful, it must be broad and open-minded enough to challenge the most basic premises and to consider the strongest alternatives, such as whether alternate strategies, up to and including disposition of some or all of EKPC's assets, would benefit member/customers in the long-term. Liberty also believes that such a review must be self directed and from the member level to be effective. Inviting Commission oversight of the effort, however, would represent a very valuable step in demonstrating the sincerity of the effort and the commitment to change needed to promote the regulatory confidence that EKPC will need if it is to continue in a major power supply role in Kentucky. Should the distribution cooperatives fail to seize the initiative, it is reasonable to expect the Commission to do so.

To the extent that continued operation in some form is appropriate, the next step would be to create (from a bottoms-up approach and giving no preference to incumbency) a revised governance structure and a new board. Then, a restructured and reconstituted board needs to put into place a senior management team (again from a bottoms-up approach and giving no preference to incumbency) that it objectively finds capable of meeting the challenges that EKPC will face, according to the newly developed view of its future according to management and governance consistent with the needs of such an enterprise.

AFFIDAVIT

STATE OF GEORGIA)

COUNTY OF FULTON)

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

Lane Kollen

Sworn to and subscribed before me on this
28th day of June 2021.

Notary Public

RANDY A FUTRAL
MY COMMISSION EXPIRES
NOTARY
PUBLIC
AUGUST 26, 2024
COBB COUNTY, GEORGIA