Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-051

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 98. The response was incomplete. Provide the most recent allowed returns (fully or partially litigated or settled) for each of the regulated subsidiaries of the holding companies in the proxy group and the date of the awarded returns.

RESPONSE:

As stated in the original response, the allowed returns for each parent company in Dr. Morin's peer group are available from the Value Line reports for each company. Dr. Morin does not have access to the allowed returns for each of the subsidiaries of the holding companies in the proxy group, and nor was this information germane in arriving at Dr. Morin's ROE recommendation. Dr. Morin points out that quarter-by-quarter compilations of allowed returns in individual company cases are available in Regulatory Research Associates' (S&P Global Intelligence) quarterly reviews.

PERSON RESPONSIBLE: Dr. Roger A. Morin, PhD

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-052

REQUEST:

Provide the CAPM, ECAPM, Historical Risk Premium, and Allowed Risk Premium ROE estimates using the current 30-year U.S. Treasury Bond. Include all supporting documents in Excel spreadsheet format with all formulas unprotected and all rows and columns fully accessible.

RESPONSE:

The current yield on 30-year US Treasury bonds is 2.4% while the forecast yield is 4.2% from Table 2 of Dr. Morin's testimony. The difference in risk-free rate is therefore 1.8% (4.2 – 2.4 = 1.8). The CAPM, ECAPM, and Historical Risk Premium results would therefore decrease by 1.8% as shown on the table below. The Allowed Risk Premium result would decline by 0.96% using the formula on page 51 of Dr. Morin's testimony. Column 1 of the table displays the results of Dr. Morin's analyses from his summary of results on Page 59 of his testimony, while Column 2 shows the amended results using current yields.

	Forecast Rate (1)	Current Rate (2)
CAPM	8.98%	7.18%
Empirical CAPM	9.71%	7.91%
Historical Risk Premium	10.50%	8.70%
Allowed Risk Premium	10.40%	9.44%

Dr. Morin's reasons for relying on interest rate forecasts are fully discussed in his direct testimony. In short, financial models must be applied using data that reflects the expectations of actual investors in the market. While investors examine history as a guide to the future, it is the expectations of future events that influence security values and the cost of capital.

PERSON RESPONSIBLE: Dr. Roger A. Morin, PhD

STAFF-DR-03-053

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 117, and Scheduled L-2.2, pages 174 and 176 of 180. State when Duke Kentucky discontinued the Payment Advantage Program and how customers were notified of the change.

RESPONSE:

The Payment Advantage Program was not discontinued. Please see Schedule L-2.2 page 178 of 180. This option is still available as "Automatically from your bank account" under "Convenient ways to pay your bill."

PERSON RESPONSIBLE: Jeff L. Kern

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-054

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 122, Attachment 1, and the Reynolds Testimony at 9. State whether the incentive payment for the Residential EV Charging Program will be $1,063 or $563. If the intended incentive payment is $1,063, provide a corrected STAFF-DR-02-122 Attachment 1.

RESPONSE:

The customer incentive payment for the Residential EV Charging Program consists of an initial upfront payment of $500 and then an on-going participation incentive of up to $500 over three years for a potential total payment of $1000 to the customer. The additional $63 is budgeted for Duke Energy Kentucky costs to perform this program. STAFF-DR-02-122 Attachment 1 illustrates this by including the upfront incentive and program costs in line 11 as $563 and then the participation incentive is shown as the $50,000 annual O&M cost (300 customers with a potential $166.67 annual participation payment is $50,000).

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-055

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 123(a). Duke Kentucky states, "As Mr. Reynolds discusses on Lines 3-7, the electric usage that the charging station generates will be billed under the charging station customer's existing commercial rate – those rates are discussed by Mr. Kern." Confirm that this statement is referencing the Electric Transit Bus Charging Program and not the Fast Charge Fee.

RESPONSE:

Correct. The reference of Reynolds' lines 3-7 references page 14 in Reynolds direct testimony. This reference was included with Staff Second Request, Item 123(a) as a sidenote of what Mr. Kern described in his testimony relating to the ET Pilot.

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-056

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 123(c).

a. Provide Staff-DR-02-123 Attachment 1 in Excel spreadsheet format with all formulas intact and unprotected and with all columns and rows accessible.

b. Provide support for the number of kWh per month used in the EV Fast Charge Fee Calculation.

c. Explain the component in Staff-DR-02-125 Attachment 1 that is labeled "CC Adder."

d. Identify the components of the calculation that could change quarterly.

RESPONSE:

a. Please see STAFF-DR-02-123 Attachment 1.

b. Please reference STAFF-DR-02-090 Attachment, Estimated Net Revenue from EV Fast Charging. Under year 1, the average kWh/Mo per meter (2 units) was predicted to be 2,167 kWh at 3% utilization. This is the expected kWh consumption of both EV Fast Charging stations per site used approximately 45 minutes per day in year one. This equates to 1-3 EV Fast Charging sessions per day at each site.

c. Referencing STAFF-DR-02-1<u>23</u> Attachment 1, not STAFF-DR-02-<u>125</u> Attachment 1. "CC Adder" stands for Customer Charge Adder. This essentially spreads the monthly customer charge over the estimated amount of kWh consumed in a month.

d. The FAC, PSM, ESM and DSMR riders could change quarterly.

Please note that the Company will only modify the Fast Charge Fee if the quarterly review of the statewide average Fast Charge Fee has changed since the previous quarter. If so, then the most recent inputs will be used to calculate a new Fast Charge Fee.

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-057

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 124. Explain how Duke Kentucky proposes to reflect the monthly changes in its Fuel Adjustment Clause and Environmental Surcharge Mechanism in the quarterly rate calculation.

RESPONSE:

Duke Energy Kentucky will utilize the most recent monthly value of the FAC and ESM in the quarterly rate calculation. i.e. if the Fast Charge Fee is reviewed in January, the December FAC and ESM values will be used.

PERSON RESPONSIBLE: Lang Reynolds
Jeff L. Kern

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-058

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 129, and the Reynolds Testimony, page 6. Explain how the pilot will be limited to 36 months if the participants must contract for the excepted life of the charging station.

RESPONSE:

Staff Second Request, Item 129 and Item 127, and Reynolds Testimony, page 15, lines 1-2 all state that the Company proposes to operate the Electric Transit Bus infrastructure for the life of the unit, not 36 months. This is to ensure that the program investments are not stranded assets. The 36-month pilot is limited in duration to provide accurate information and a timeline for subsequent and appropriate programs following this pilot.

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-059

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 130, Attachment, pages 3-6 of 6. Confirm that "Program Implementation Costs" are the costs of the participants and not Duke Kentucky. If this cannot be confirmed, explain the nature of the implementation costs.

RESPONSE:

"Program Implementation Costs" as noted in Staff's Second Request, Item 130, Attachment, pages 3-6 of 6 refers to the cost that Duke Energy Kentucky would incur if the entire incentive per unit cost and incentive quantity was implemented over five years as suggested by the study.

PERSON RESPONSIBLE: Lang Reynolds

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-060

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 130, Attachment, page 5, and Item 131, and the Reynolds Testimony at 9, Table 1. Explain the differences in the proposed incentives and the medium level incentives.

RESPONSE:

Please see below for a comparison of the non-road incentives the Company proposed against the medium-level incentives studied in the Cost Benefit Analysis. In general, the Company strategy was to offer incentives of value that would encourage customers to convert to electric, all while protecting the overall spend of the program. Each individual incentive amount was set equal or slightly below the medium level incentive in the CBA study for overall simplicity of the program.

Table STAFF-DR-03-060 - Individual Non-Road Rebates

Description (all-electric)	Proposed Amount	Pilot Quantity	Study Amount (med)	Study Quantity (med)
Fork Truck	$1,500	45	$1,600 / $1,800	142 / 53
Standby Truck Refrigeration	$1,500	45	$1,500	337
Airport Ground Service	$1,000	100	$2,100	4
Airport Ground Power	$15,000	5	$15,500	18
Totals	***$310,000***		***$1,115,500***	

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-061

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 130, Attachment, page 1 of 6, and Item 131. Confirm that the "no incentive" scenario has the highest rate impact measure score. If this cannot be confirmed, explain.

RESPONSE:

Please see Staff's Second Request, Item 130, Attachment, page 2 of 6 for a comparison of the study's different incentive levels and their respective scores. The "no incentive" scenario does have the highest RIM score, but also has a lower total RIM Net Benefit when compared to the "Medium" and "High Incentive" scenarios. Furthermore, Company affiliates have attempted to offer the no incentive scenario recently, without any successful adoption from customers. The Company therefore proposed incentives aligned with the "Medium Incentive" scenario as the most appropriate to deliver ratepayer benefits while achieving a significant level of participation.

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-062

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Items 132 and 135, and the Reynolds Testimony, Attachment LWR-1. Confirm that benefits to Duke Kentucky's ratepayers mostly accrue from managed charging. If confirmed, explain why Duke Kentucky does not propose a more aggressive approach to managed charging as part of the program.

RESPONSE:

Please note that this Cost-Benefit Analysis covers Kentucky overall statewide, not just Duke Energy Kentucky. The study does show that incremental EVs only provide long-term ratepayer benefits if charging is managed per Page 9, Figures 10 and 11.

The Pilot is designed to gather the data necessary to determine the effect of EV charging by Duke Energy Kentucky customers on Duke Energy Kentucky's system specifically rather than overall statewide averages. Therefore, it is possible that EV charging could be a net benefit to the Duke Energy Kentucky system even without load management. Nonetheless, the Company has indeed proposed an aggressive approach to managed charging as part of its Residential EV Charging program.

PERSON RESPONSIBLE: Lang Reynolds

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-063

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 133. Explain whether Duke Kentucky has evaluated whether level two charging station installation costs have changed significantly since 2013.

RESPONSE:

Duke Energy Kentucky has evaluated and monitored the average costs to install level two charging stations since 2013. Residential level two charging station installations have not significantly changed from the $1400 average found by Project Plug-IN. Although more variable, Commercial level two charging installations vary from $3,000-$10,000 per port or more depending on site work. Connectivity of level two charging stations has increased hardware and ongoing site host costs.

PERSON RESPONSIBLE: Lang Reynolds

STAFF-DR-03-064

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 139.b. Confirm that three of the five pilot programs consist entirely of incentive payments, which are not part of Duke Kentucky's existing tariffed rates. If confirmed, explain why Duke Kentucky contends that "no changes to the tariffs would be required."

RESPONSE:

Yes, three of the five programs (Non-Road Electrification, Residential EV, and Commercial EV Charging) are incentive payments proposed to be deferred as an O&M expense. Please reference the Direct Testimony of Sarah Lawler, page 17, lines 1-22.

The Company did not think that a tariff would be necessary for a limited term pilot. However, the Company is not opposed to including one if the Commission determines that the Company should make this limited pilot a tariffed offering.

PERSON RESPONSIBLE: Jeff L. Kern

STAFF-DR-03-065

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 140, the Reynolds Testimony, page 18, lines 14-22, through page 19, lines 1-5, and Attachment LWR-1. Explain whether Duke Kentucky's proposed load-managed incentive satisfies the definition of "managed charging" used in Attachment LWR-1.

RESPONSE:

It is important to reiterate that the Cost-Benefit Analysis provides a high-level view of the potential opportunity for EV growth to provide ratepayer benefits across Kentucky as a whole. The Pilot program is designed to gather necessary additional data from Duke Energy Kentucky customers on the Duke Energy Kentucky system in order to determine the specific impacts of EV charging within Duke Energy Kentucky territory. The Residential EV Charging Program is designed to also designed to determine the extent to which customers are willing to participate in charging load management and the possible value such management can provide to the utility system. Nonetheless, the study described managed charging as a scenario in which a "significant portion of EV drivers who normally start charging between 12p-11p each day delay the start of charging until after midnight." By managing charging such that it is significantly reduced during on-peak periods, the Company believes the proposed program delivers substantively the same results as the "Managed Charging" scenario described in the Cost-Benefit Analysis.

PERSON RESPONSIBLE: Lang Reynolds

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-066

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 157.

a. For the period of September 2017 through August 2019, provide the expense of fuel (F), sales (S), and the resulting Fuel Adjustment Clause (FAC) rate noted as $/kWh using the proposed rolling 12 months average in Excel spreadsheet format with all formulas intact and unprotected and with all columns and rows accessible.

b. For the period of September 2017 through August 2019, provide a comparison of the rolling 12 months average FAC rate against the base rate approved in Case No. 2017-0005.

RESPONSE:

a. See STAFF-DR-03-066 Attachment.

b. See STAFF-DR-03-066 Attachment.

PERSON RESPONSIBLE: William Don Wathen Jr.

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Expense Month -->		Oct 2016 Dollars ($)	Nov 2016 Dollars ($)	Dec 2016 Dollars ($)	Jan 2017 Dollars ($)	Feb 2017 Dollars ($)	Mar 2017 Dollars ($)	Apr 2017 Dollars ($)	May 2017 Dollars ($)
A. Company Generation									
Coal Burned	(+)	$ 9,070,471.82	$ 7,054,855.00	$ 6,189,749.52	$ 9,352,399.44	$ 7,368,098.81	$ 9,054,528.16	$ 7,688,930.87	$ 6,127,844.65
Oil Burned	(+)	40,235.54	53,822.31	223,681.78	275,114.75	116,256.51	48,065.18	(120,683.95)	154,017.34
Gas Burned	(+)	302,508.89	71,007.00	(10,369.29)	101,046.79	108,310.18	145,303.78	276.67	355,506.08
Net Fuel Related RTO Billing Line Items	(-)	250,147.66	141,969.62	45,979.80	172,048.10	20,837.34	222,870.30	-	52,190.73
Fuel (assigned cost during Forced Outage[a])	(+)	-	-	2,731,718.47	-	490,556.16	-	8,507.07	-
Fuel (substitute cost during Forced Outage[a])	(-)	-	-	5,125.96	-	-	-	-	-
Sub-Total		$ 9,163,068.59	$ 7,037,714.69	$ 9,083,674.72	$ 9,556,512.88	$ 8,062,384.32	$ 9,025,026.82	$ 7,577,030.66	$ 6,585,177.34
B. Purchases									
Economy Purchases	(+)	$ 17,793.64	$ 1,084,964.73	$ 4,790,674.00	$ 101,854.63	$ 717,773.12	$ 29,926.01	$ 668,465.85	$ 3,650,907.57
Other Purchases	(+)	-	-	-	-	-	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	-	24,811.00	4,183,163.86	-	501,507.75	-	9,867.25	-
Less purchases above highest cost units	(-)	-	-	-	-	-	-	-	-
Sub-Total		$ 17,793.64	$ 1,060,153.73	$ 607,510.14	$ 101,854.63	$ 216,265.37	$ 29,926.01	$ 658,598.60	$ 3,650,907.57
C. Non-Native Sales Fuel Costs		$ 2,055,298.21	$ 1,106,840.99	$ 878,773.04	$ 1,470,644.28	$ 1,283,973.17	$ 1,792,827.50	$ 1,840,959.61	$ 1,167,539.04
D. Total Fuel Costs (A + B - C) [b]	(+)	$ 7,125,564.02	$ 6,991,027.43	$ 8,812,411.82	$ 8,187,723.23	$ 6,994,676.52	$ 7,262,125.33	$ 6,394,669.65	$ 9,068,545.87
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 184,166.30	$ 229,768.25	$ (254,185.60)	$ (448,781.13)	$ 166,229.13	$ 226,105.88	$ (18,164.58)	$ 218,035.58
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ 49,599.94	$ 21,053.57	$ 100,728.50	$ 21,588.98	$ 43,287.40	$ 60,559.09	$ 20,259.11	$ 7,775.17
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (41,169.79)	$ (43,252.39)	$ (92,733.64)	$ (30,168.85)	$ 6,440.47	$ (39,052.53)	$ (7,839.97)	$ 24,708.86
H. Prior Period Correction	(+)	$ -	$ -	$ (683,877.16)	$ (683,877.16)	$ (683,877.16)	$ (683,877.16)	$ (683,877.16)	$ (683,877.16)
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 6,949,827.87	$ 6,739,060.36	$ 8,390,715.12	$ 7,944,047.33	$ 6,194,298.10	$ 6,373,648.86	$ 5,741,376.21	$ 8,199,117.16

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Estimated - to be trued up in the filing next month

	Oct 2016	Nov 2016	Dec 2016	Jan 2017	Feb 2017	Mar 2017	Apr 2017	May 2017
Sales Sm (Schedule 3, Line C)	299,818,002	288,985,005	348,315,447	340,461,039	287,160,082	317,252,437	283,666,941	312,784,517
Caclulated Fuel Rate	0.02318	0.02332	0.024089	0.023333	0.021571	0.02009	0.02024	0.026213
Base Fuel Rate	0.029117	0.029117	0.029117	0.029117	0.029117	0.029117	0.029117	0.029117
Monthly FAC Rate	(0.005937)	(0.005797)	(0.005028)	(0.005784)	(0.007546)	(0.009027)	(0.008877)	(0.002904)

12 Month Rolling Average Fuel Cost
12 Month Rolling Average Sales
12 Month Rolling Average Calculated Fuel Rate
Base Fuel Rate
12 Month Rolling Average FAC Rate

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Expense Month -->		Jun 2017 Dollars ($)	Jul 2017 Dollars ($)	Aug 2017 Dollars ($)	Sep 2017 Dollars ($)	Oct 2017 Dollars ($)	Nov 2017 Dollars ($)	Dec 2017 Dollars ($)	Jan 2018 Dollars ($)
A. Company Generation									
Coal Burned	(+)	$ 8,076,434.41	$ 5,918,585.32	$ 8,410,962.72	$ 7,067,050.90	$ 7,229,507.91	$ 7,334,313.23	$ 6,652,531.75	$ 7,496,211.49
Oil Burned	(+)	46,980.42	194,431.48	53,003.10	135,606.95	167,018.69	167,287.97	219,998.46	92,153.99
Gas Burned	(+)	268,491.41	397,836.45	51,365.00	80,840.00	98,550.00	(1,033.50)	303,000.00	2,911,200.00
Net Fuel Related RTO Billing Line Items	(-)	-	77,833.72	84,249.28	41,151.53	108,161.33	-	-	206,758.73
Fuel (assigned cost during Forced Outage[a])	(+)	12,134.95	2,096,859.50	55,430.21	799,030.69	90,515.50	67,754.59	746,983.17	27,613.42
Fuel (substitute cost during Forced Outage[a])	(-)	-	-	-	15,968.93	-	-	-	-
Sub-Total		$ 8,404,041.19	$ 8,529,879.03	$ 8,486,511.75	$ 8,025,408.08	$ 7,477,430.77	$ 7,568,322.29	$ 7,922,513.38	$ 10,320,420.17
B. Purchases									
Economy Purchases	(+)	$ 479,223.36	$ 5,131,236.65	$ 756,806.60	$ 2,015,211.65	$ 1,613,916.51	$ 1,486,190.59	$ 2,445,729.75	$ 2,384,092.19
Other Purchases	(+)	-	-	-	-	-	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	20,406.57	2,881,781.18	62,318.81	1,333,305.57	137,799.07	115,694.42	1,170,777.68	35,823.55
Less purchases above highest cost units	(-)	-	-	-	-	-	-	-	-
Sub-Total		$ 458,816.79	$ 2,249,455.47	$ 694,487.79	$ 681,906.08	$ 1,476,117.44	$ 1,370,496.17	$ 1,274,952.07	$ 2,348,268.64
C. Non-Native Sales Fuel Costs		$ 647,824.43	$ 323,599.89	$ 448,184.96	$ 961,966.04	$ 1,989,715.02	$ 1,414,777.90	$ 767,258.72	$ 1,634,412.35
D. Total Fuel Costs (A + B - C) [b]	(+)	$ 8,215,033.55	$ 10,455,734.61	$ 8,732,814.58	$ 7,745,348.12	$ 6,963,833.19	$ 7,524,040.56	$ 8,430,206.73	$ 11,034,276.46
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (455,922.12)	$ (186,258.58)	$ (68,234.73)	$ 72,007.88	$ 310,730.86	$ 12,845.10	$ (36,872.84)	$ 388,950.20
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx (actual) - $xxx,xxx (estimate)	(+)	$ 140,688.26	$ 190,752.59	$ 113,327.29	$ 38,038.91	$ 40,053.85	$ 237,612.42	$ 29,083.29	$ 66,848.45
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (3,524.82)	$ 3,997.25	$ 4,569.39	$ 11,165.22	$ (28,771.10)	$ (9,228.47)	$ (3,941.72)	$ (1,539.99)
H. Prior Period Correction	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (180,128.84)
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 8,808,119.11	$ 10,836,743.03	$ 8,918,945.99	$ 7,722,544.37	$ 6,664,385.08	$ 7,739,579.41	$ 8,492,221.14	$ 10,530,505.88

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Estimated - to be trued up in the filing next month

	Jun 2017	Jul 2017	Aug 2017	Sep 2017	Oct 2017	Nov 2017	Dec 2017	Jan 2018
Sales Sm (Schedule 3, Line C)	353,538,927	391,174,764	373,168,291	317,739,674	289,878,102	298,880,302	353,509,454	381,703,779
Caclulated Fuel Rate	0.024914	0.027703	0.023901	0.024305	0.02299	0.025895	0.024023	0.027588
Base Fuel Rate	0.029117	0.029117	0.029117	0.023837	0.023837	0.023837	0.023837	0.023837
Monthly FAC Rate	(0.004203)	(0.001414)	(0.005216)	0.000468	(0.000847)	0.002058	0.000186	0.003751
12 Month Rolling Average Fuel Cost				$ 7,734,870.29	$ 7,711,083.39	$ 7,794,459.98	$ 7,802,918.81	$ 8,018,457.03
12 Month Rolling Average Sales				326,172,094	325,343,769	326,168,377	326,601,211	330,038,106
12 Month Rolling Average Calculated Fuel Rate				0.023714	0.023701	0.023897	0.023891	0.024296
Base Fuel Rate				0.023837	0.023837	0.023837	0.023837	0.023837
12 Month Rolling Average FAC Rate				(0.000123)	(0.000136)	0.000060	0.000054	0.000459

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Expense Month -->		Feb 2018 Dollars ($)	Mar 2018 Dollars ($)	Apr 2018 Dollars ($)	May 2018 Dollars ($)	Jun 2018 Dollars ($)	Jul 2018 Dollars ($)	Aug 2018 Dollars ($)	Sep 2018 Dollars ($)
A. Company Generation									
Coal Burned	(+)	$ 6,006,357.54	$ 272,812.20	$ -	$ -	$ 2,517,861.20	$ 7,264,512.18	$ 7,012,868.26	$ 5,081,026.45
Oil Burned	(+)	153,313.44	118,366.25	-	-	409,004.42	134,362.64	179,851.12	496,138.17
Gas Burned	(+)	(6,931.05)	418,297.62	298,000.00	621,965.50	1,180,060.00	1,542,630.00	619,965.36	471,026.40
Net Fuel Related RTO Billing Line Items	(-)	-	117,105.62	125,725.91	101,782.10	1,758,957.38	(476,880.10)	(373,800.55)	(93,342.70)
Fuel (assigned cost during Forced Outage[a])	(+)	526,215.73	-	-	-	-	26,481.24	9,326.84	125,467.02
Fuel (substitute cost during Forced Outage[a])	(-)	2,957.20	-	-	-	-	19,894.91	-	51,397.33
Sub-Total		$ 6,675,998.46	$ 692,370.45	$ 172,274.09	$ 520,183.40	$ 2,347,968.24	$ 9,424,971.25	$ 8,195,812.13	$ 6,215,603.41
B. Purchases									
Economy Purchases	(+)	$ 1,653,706.65	$ 10,052,776.36	$ 9,348,472.44	$ 12,161,090.48	$ 9,127,231.96	$ 1,547,872.41	$ 2,507,288.78	$ 3,829,724.90
Other Purchases	(+)	-	-	-	-	-	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	727,785.94	-	-	-	-	49,226.20	9,591.79	200,995.91
Less purchases above highest cost units	(-)	-	-	-	-	5,800.42	2,465.64	-	-
Sub-Total		$ 925,920.71	$ 10,052,776.36	$ 9,348,472.44	$ 12,161,090.48	$ 9,121,431.54	$ 1,496,180.57	$ 2,497,696.99	$ 3,628,728.99
C. Non-Native Sales Fuel Costs		$ 207,285.81	$ 40,227.90	$ 218.28	$ -	$ 179,695.46	$ 928,973.16	$ 263,122.55	$ 524,209.81
D. Total Fuel Costs (A + B - C) [b]	(+)	$ 7,394,633.36	$ 10,704,918.91	$ 9,520,528.25	$ 12,681,273.88	$ 11,289,704.32	$ 9,992,178.66	$ 10,430,386.57	$ 9,320,122.59
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (4,351.82)	$ (267,838.85)	$ 18,602.40	$ (235,839.64)	$ 880,902.80	$ 613,353.93	$ 556.53	$ (1,883.39)
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ 37,170.40	$ 50,007.49	$ 76,877.47	$ (330,298.82)	$ (622,570.83)	$ (503,047.29)	$ 29,620.62	$ (15,988.71)
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (81,708.40)	$ 79,757.88	$ 83,631.72	$ 130,354.30	$ 42,057.07	$ 531,469.91	$ 776,965.71	$ 145,600.89
H. Prior Period Correction	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 7,354,447.18	$ 11,102,523.13	$ 9,662,435.04	$ 12,717,169.00	$ 9,828,287.76	$ 9,407,247.35	$ 11,236,416.37	$ 9,451,618.16

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Estimated - to be trued up in the filing next month

	Feb 2018	Mar 2018	Apr 2018	May 2018	Jun 2018	Jul 2018	Aug 2018	Sep 2018
Sales Sm (Schedule 3, Line C)	296,114,070	318,397,259	283,357,974	347,890,413	370,037,555	389,400,238	389,106,706	338,926,293
Caclulated Fuel Rate	0.024837	0.03487	0.0341	0.036555	0.02656	0.024158	0.028877	0.027887
Base Fuel Rate	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837
Monthly FAC Rate	0.001000	0.011033	0.010263	0.012718	0.002723	0.000321	0.005040	0.004050
12 Month Rolling Average Fuel Cost	$ 8,115,136.12	$ 8,509,208.97	$ 8,835,963.87	$ 9,212,468.19	$ 9,297,482.25	$ 9,178,357.61	$ 9,371,480.14	$ 9,515,569.62
12 Month Rolling Average Sales	330,784,272	330,879,673	330,853,926	333,779,417	335,154,303	335,006,426	336,334,627	338,100,179
12 Month Rolling Average Calculated Fuel Rate	0.024533	0.025717	0.026707	0.0276	0.027741	0.027398	0.027864	0.028144
Base Fuel Rate	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837
12 Month Rolling Average FAC Rate	0.000696	0.001880	0.002870	0.003763	0.003904	0.003561	0.004027	0.004307

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Expense Month --->		Oct 2018 Dollars ($)	Nov 2018 Dollars ($)	Dec 2018 Dollars ($)	Jan 2019 Dollars ($)	Feb 2019 Dollars ($)	Mar 2019 Dollars ($)	Apr 2019 Dollars ($)	May 2019 Dollars ($)
A. Company Generation									
Coal Burned	(+)	$ 6,170,882.46	$ 5,859,729.72	$ 8,119,386.22	$ 7,804,600.11	$ 6,375,406.95	$ 7,716,650.54	$ -	$ 6,127,616.78
Oil Burned	(+)	61,796.55	298,376.93	145,061.75	88,987.82	194,311.15	82,735.99	341,053.26	1,597,426.43
Gas Burned	(+)	336,950.00	137,000.00	-	617,000.00	104,975.00	219,825.83	115,810.00	86,432.27
Net Fuel Related RTO Billing Line Items	(-)	(31,177.16)	(297,761.37)	(184,119.36)	(408,723.59)	(155,935.29)	(195,032.27)	(8,045.74)	(197,048.94)
Fuel (assigned cost during Forced Outage[a])	(+)	936,187.19	15,599.76	18,846.44	-	-	-	475,563.09	18,459.01
Fuel (substitute cost during Forced Outage[a])	(-)	140,017.89	-	-	-	-	-	26,632.24	-
Sub-Total		$ 7,396,975.47	$ 6,608,467.78	$ 8,467,413.77	$ 8,919,311.52	$ 6,830,628.39	$ 8,214,244.63	$ 913,839.85	$ 8,026,983.43
B. Purchases									
Economy Purchases	(+)	$ 2,480,118.40	$ 2,886,970.59	$ 1,397,520.22	$ 702,360.50	$ 1,249,884.18	$ 374,958.53	$ 8,030,904.84	$ 1,618,120.40
Other Purchases	(+)	-	-	-	-	-	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	1,606,960.62	26,602.32	29,667.17	-	-	-	717,496.71	27,462.08
Less purchases above highest cost units	(-)	-	-	-	-	-	-	-	-
Sub-Total		$ 873,157.78	$ 2,860,368.27	$ 1,367,853.05	$ 702,360.50	$ 1,249,884.18	$ 374,958.53	$ 7,313,408.13	$ 1,590,658.32
C. Non-Native Sales Fuel Costs		$ 799,147.67	$ 1,020,329.93	$ 1,187,115.45	$ 791,941.99	$ 527,239.13	$ 1,072,180.04	$ -	$ 1,553,367.72
D. Total Fuel Costs (A + B - C) [b]	(+)	$ 7,470,985.58	$ 8,448,506.12	$ 8,648,151.37	$ 8,829,730.03	$ 7,553,273.44	$ 7,517,023.12	$ 8,227,247.98	$ 8,064,274.03
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ (330,103.57)	$ (158,307.45)	$ 27,570.34	$ 253,999.88	$ 80,289.14	$ 8,233.59	$ (26,600.36)	$ (19,431.26)
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ 118,644.07	$ (68,759.51)	$ 25,390.70	$ (28,361.99)	$ 35,943.78	$ 6,659.59	$ 228,402.26	$ 14,140.98
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ (56,701.60)	$ (14,696.38)	$ (223,225.32)	$ (21,777.78)	$ 341,991.26	$ 363,517.17	$ 139,204.34	$ 111,055.80
H. Prior Period Correction	(+)	$ -	$ -	$ 5,257.65	$ -	$ -	$ -	$ -	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 7,863,031.62	$ 8,523,357.68	$ 8,428,004.06	$ 8,525,590.38	$ 7,850,919.34	$ 7,878,966.29	$ 8,621,454.94	$ 8,208,902.07

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Estimated - to be trued up in the filing next month

	Oct 2018	Nov 2018	Dec 2018	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019
Sales Sm (Schedule 3, Line C)	318,493,683	302,546,150	320,128,370	360,508,145	311,550,137	324,600,422	277,297,282	313,035,746
Caclulated Fuel Rate	0.024688	0.028172	0.026327	0.023649	0.0252	0.024273	0.031091	0.026224
Base Fuel Rate	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837
Monthly FAC Rate	0.000851	0.004335	0.002490	(0.000188)	0.001363	0.000436	0.007254	0.002387
12 Month Rolling Average Fuel Cost	$ 9,615,456.84	$ 9,680,771.69	$ 9,675,420.27	$ 9,508,343.98	$ 9,549,716.66	$ 9,281,086.92	$ 9,194,338.58	$ 8,818,649.67
12 Month Rolling Average Sales	340,484,811	340,790,298	338,008,541	336,242,238	337,528,577	338,045,507	337,540,450	334,635,894
12 Month Rolling Average Calculated Fuel Rate	0.02824	0.028407	0.028625	0.028278	0.028293	0.027455	0.027239	0.026353
Base Fuel Rate	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837	0.023837
12 Month Rolling Average FAC Rate	0.004403	0.004570	0.004788	0.004441	0.004456	0.003618	0.003402	0.002516

DUKE ENERGY KENTUCKY
FUEL COST SCHEDULE

Expense Month --->		June 2019 Dollars ($)	July 2019 Dollars ($)	August 2019 Dollars ($)
A. Company Generation				
Coal Burned	(+)	$ 6,886,576.29	$ 7,792,476.92	$ 7,221,948.34
Oil Burned	(+)	1,206,429.41	89,511.11	135,065.87
Gas Burned	(+)	268,640.00	1,696,952.57	513,332.32
Net Fuel Related RTO Billing Line Items	(-)	(366,264.67)	(399,787.94)	(331,490.49)
Fuel (assigned cost during Forced Outage[a])	(+)	7,287.53	-	-
Fuel (substitute cost during Forced Outage[a])	(-)	-	-	-
Sub-Total		$ 8,735,197.90	$ 9,978,728.54	$ 8,201,837.02
B. Purchases				
Economy Purchases	(+)	$ 584,141.73	$ 1,237,103.25	$ 1,492,498.27
Other Purchases	(+)	-	-	-
Other Purchases (substitute for Forced Outage[a])	(-)	7,287.53	-	-
Less purchases above highest cost units	(-)	-	-	-
Sub-Total		$ 576,854.20	$ 1,237,103.25	$ 1,492,498.27
C. Non-Native Sales Fuel Costs		$ 1,182,889.39	$ 1,087,264.32	$ 401,190.79
D. Total Fuel Costs (A + B - C) [b]	(+)	$ 8,129,162.71	$ 10,128,567.47	$ 9,293,144.50
E. Total Company Over or (Under) Recovery from Schedule 5, Line 14	(-)	$ 345,247.81	$ 193,071.30	$ (167,396.33)
F. Adjustment indicating the difference in actual fuel cost for the month of xxxx 20xx and the estimated cost orginally reported $xxx,xxx - $xxx,xxx (actual) (estimate)	(+)	$ (1,097,277.67)	$ (90,314.27)	$ (261,305.06)
G. RTO Resettlements for prior periods from Schedule 6, Line G	(+)	$ 3,773.25	$ 57,810.23	$ (13,794.96)
H. Prior Period Correction	(+)	$ -	$ 85,883.13	$ -
I. Deferral of Current Purchased Power Costs	(-)	$ -	$ -	$ -
J. Amount of Deferred Purchased Power Costs included in the filing	(+)	$ -	$ -	$ -
K. Grand Total Fuel Cost (D - E + F + G + H - I + J)		$ 6,690,410.48	$ 9,988,875.26	$ 9,185,440.81

Note: [a] Forced Outage as defined in 807 KAR 5:056.
[b] Estimated - to be trued up in the filing next month

	June 2019	July 2019	August 2019
Sales Sm (Schedule 3, Line C)	327,491,403	402,802,025	381,645,933
Caclulated Fuel Rate	0.020429	0.024798	0.024068
Base Fuel Rate	0.023837	0.023837	0.023837
Monthly FAC Rate	(0.003408)	0.000961	0.000231
12 Month Rolling Average Fuel Cost	$ 8,557,159.89	$ 8,605,628.89	$ 8,434,714.26
12 Month Rolling Average Sales	331,090,381	332,207,197	331,585,466
12 Month Rolling Average Calculated Fuel Rate	0.025845	0.025904	0.025438
Base Fuel Rate	0.023837	0.023837	0.023837
12 Month Rolling Average FAC Rate	0.002008	0.002067	0.001601

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-067

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 159.

a. Explain each basis for Duke Kentucky's contention that revenue arising from Regulation and Frequency Response Service Reserves and Synchronized Reserves are "[f]uel costs (F)" as that term is used in 807 KAR 5:056, section 1(3), including whether and, if so, why Duke Kentucky contends those revenues fall under subpart (a), (b), (c), (d), or (e) of Section 1(3).

b. Explain whether Duke Kentucky contends that all costs to generate energy to change the batteries that will be used in the proposed battery project, whether the generation is owned by Duke Kentucky or purchased, are "[f]uel costs (F)" as that term is used in 807 KAR 5:056, Section 1(3), and explain each basis for Duke Kentucky's contention, including whether and, if so, why Duke Kentucky contends those costs fall under subpart (a), (b), (c), (d), or (e) of Section 1(3).

c. Explain whether Duke Kentucky contends that all costs to transmit energy from the point of generation to charge the batteries that will be used in the proposed battery project, whether the transmission and distribution assets are owned by Duke Kentucky or not, are "[f]uel costs (F)" as that term is used in 807 KAR 5:056, Section 1(3), and explain each basis for Duke Kentucky's contention, including whether and, if so, why Duke Kentucky contends those costs fall under subject (a), (b), (c), (d), or (e) of Section 1(3).

d. Describe what is included in PJM billing line items 1200, 1205, 1210, 1215, 1220, 1225, 1303, 1313, 1314, and 1999, and explain each basis for Duke Kentucky's contention that those items are "[f]uel costs (F)" as that term is used in 807 KAR 5:056, section 1(3), including whether and, if so, why Duke Kentucky contends those revenues fall under subpart (a), (b), (c), (d), or (e) of Section 1(3).

RESPONSE:

The following responses relate only to 807 KAR 5:056, section 1(3), subparts (a), (b), (c) and (d) as there does not appear to be a subpart (e) in the regulation.

a. Duke Energy Kentucky contends that revenue arising from Regulation and Frequency Response Service Reserves and Synchronized Reserves are deemed fuel costs for the reasons discussed in the direct testimony of John D. Swez in the Company's last electric base rate case, Case No. 2017-00321. The Commission Order in Case No. 2017-00321 said the following:

> "Rider FAC, Fuel Adjustment Clause. Duke Kentucky is proposing to include additional PJM Interconnection, LLC ("PJM") Billing Line Items for recovery through its FAC. Duke Kentucky's proposal is the same, with respect to the PJM billing line items, as was made by Kentucky Power in its recent base-rate proceeding and approved by the Commission. There were no objections to this tariff change from the intervenors. The Commission will approve Duke Kentucky's proposal with the requirement that Duke Kentucky list each of the PJM billing line items that will flow through the FAC in its compliance tariff."

b. Duke Energy Kentucky contends that all costs to generate energy to charge the batteries, whether the generation is owned by the Company or purchased will be considered fuel costs. See response to items (a) and (d).

c. The cost of energy to charge the battery is a fuel cost. This energy is purchased power and is the result of other generators in PJM consuming fuel. As previously mentioned, the vast majority of the revenues from the proposed battery are ancillary services revenues from the supply of regulation reserves, specifically Regulation and Frequency Response Service Reserves (PJM BLI 2340). The purchased power expense is a necessary charge needed to enable the battery to produce this ancillary service. Note that, any positive generation from the proposed battery would also be allocated 100% to native load in the FAC.

Most of the charges needed to supply regulation reserves to PJM would be the cost to charge up the battery, or essentially what the same as off-line auxiliary energy usage at a conventional power plant. This would be represented on the PJM settlement statement as either the Day-Ahead Spot Market Energy, Transmission Congestion, and Transmission Losses charge (PJM BLI 1200, BLI 1210, and BLI 1220) or the Balancing Spot Market Energy, Transmission Congestion, and Transmission Losses charge (PJM BLI's 1205, 1215, and 1225). Since Duke Energy Kentucky is expected to at least initially offer the battery in the Real-Time market, the auxiliary energy charges would be Balancing Spot Market charges.

The important difference in the auxiliary energy charges at a battery and that of conventional power plant is that, for a battery, the charge would occur much more frequently. Since the proposed battery has a relatively small amount of energy storage, the value of this battery is not in charging when LMP's are low and discharging when LMP's are high (i.e. energy arbitrage). Instead, the proposed battery would charge much more often, many times multiple times per hour, but typically this would integrate to a small amount in most hours. There are multiple reasons for this;

- Due to the extremely fast ramp rate and 3.4 MW/6 MWhr characteristics of these assets, they are expected to primarily provide ancillary services as the main product, specifically regulation reserves, and not the supply of energy. Providing ancillary services will have a real-time impact on the battery's state of charge (SOC), the direction and magnitude of which depends on the nature of the ancillary deployment by the ISO. To maintain the ideal SOC for ancillary service, the battery may need to supply or draw energy without the purpose of energy arbitrage.
- Since these assets are batteries with limited storage capability and will typically both produce energy and consume energy rapidly inside of an hour, the integrated amount of generation for the hour will typically be closer to 0 MW (or even slightly less than 0 MW), and not typically +6 MWhr or -6 MWhr for the hour. Charging or discharging 6 MWhr in an hour would result in the battery having a state of charge (SOC) at either 100% or 0%, both of which limit the ability to perform full regulation in that state. Thus, this is not typically an ideal SOC.
- Since the batteries have less than a 100% efficiency, the batteries will consume more energy than produced and assuming the battery is deployed for frequency regulation service evenly in the up and down directions, there would typically be a very small amount of negative energy in an hour representing the efficiency losses of the battery.

Finally, note that the battery is proposed to be connected at the distribution level and not the transmission level.

d. See response to item (a).

- **1200 - Day-Ahead Spot Market Energy:** BLI 1200 represents the net day-ahead energy component. Generally, revenue is being received when generation clears the day-ahead market and an expense is incurred for load purchased in the Day-Ahead market at the hourly PJM-wide day-ahead system energy price.
- **1205 – Balancing Spot Market Energy:** BLI 1205 represents the net real-time energy component deviation between the amount of generation cleared or demand bid purchased between the Day-Ahead and Real-Time markets and is charged at the hourly PJM-wide real-time system energy price. If there is no change to the quantity of demand bought or generation sold between the Day-Ahead and Real-Time Energy Markets, there is no adjustment in balancing spot market energy.
- **1210 – Day-Ahead Transmission Congestion**: BLI 1210 represents the change in energy costs due to re-dispatch in the Day-Ahead Market during hours when the PJM transmission system is constrained and assessed to participants based on the congestion price component of LMP.
- **1215 – Balancing Transmission Congestion**: BLI 1215 represents the change in energy costs due to re-dispatching in the balancing market during hours when PJM transmission system is constrained and assessed

to participants based on the real-time congestion price component of LMP. If there is no change to the quantity of demand bought or generation sold between the Day-Ahead and Real-Time Energy Markets, there is no balancing transmission congestion charges or credits.

- **1220 – Day-Ahead Transmission Losses**: BLI 1220 represents the change in energy costs due to transmission losses in the Day-Ahead Market represented in the PJM network model and assessed to participants based on the loss component of LMP.
- **1225 – Balancing Transmission Losses**: This BLI represents the change in energy costs due to transmission losses in the balancing market as represented in the PJM network model and is assessed to participants based on the real-time loss component of LMP. If there is no change to the quantity of demand bought or generation sold between the Day-Ahead and Real-Time energy markets, there is no adjustment in balancing transmission losses charges or credits.
- PJM billing line items 1303, PJM Scheduling, System Control and Dispatch Service - Market Support, 1313, PJM Settlement, Inc., and 1314, Market Monitoring Unit (MMU) Funding are all market administration costs. The Company's response to STAFF-DR-02-159 said "In addition, other PJM billing line items that are much smaller in size would be charged to the project." These billing line items do not represent fuel costs.

- **1999 – PJM Customer Payment Default**: Since the expense related to the GreenHat default is FTR and thus fuel related, as are other FTR charges and credits, the Company believes that recovery in the FAC is appropriate like other FTR and congestion charges or credits. In addition, note that the GreenHat default cannot be isolated to the one PJM Billing Line Item. GreenHat's participation in the PJM forward looking FTR auctions has impacted other PJM billing line items that have already been charged or credited to the customer. For example, among other charges and credits, the cost to purchase Financial Transmission Rights (FTR's or PJM BLI 1500) and the amount of revenue received from Auction Revenue Rights (ARR's or PJM BLI 2510) in the PJM FTR auctions and the credit or charge from owning the FTR (the FTR payout amount or PJM BLI 2211) were all impacted by GreenHat's participation in these auctions. Thus, said in another way, had GreenHat not participated in the PJM FTR auctions, other charges and credits besides BLI 1999 related to FTR's that have already been charged or credited to the customer in the FAC would have been impacted.

  Duke Energy Kentucky has received allocations of costs related to the default of a member of PJM. At the time of the default, the defaulting company GreenHat Energy, LLC, had open Financial Transmission Right (FTR) positions extending through the 2020/2021 Planning Year. The PJM tariff defines a liquidation protocol in cases of member default. Specifically, open positions are liquidated in the next available auction. Due to the extreme size of the GreenHat open position and the potential impact on auction clearing prices, and in agreement with the stakeholder community, PJM modified the liquidation protocol from immediate liquidation to a more gradual settlement of open positions and filed for a waiver to the PJM tariff at the Federal Energy Regulatory Commission (FERC). The filing was subsequently rejected at FERC and PJM has filed for rehearing on the matter. After PJM filed for rehearing, FERC directed the parties to engage in settlement negotiations for 90-days. PJM and the stakeholders negotiated a tentative settlement with the parties related to the GreenHat default. In late 2019, the "settlement agreement" reached between PJM and the parties opposing the GreenHat settlement was submitted to FERC for approval. Until FERC approves the settlement, the impact on Duke Energy Kentucky of both previous default cost allocations as well as future allocations from the GreenHat default remain uncertain.

PERSON RESPONSIBLE: John Verderame

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-068

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 161. Provide the total net amounts that Duke Kentucky expects to be in each deferral at the end of each fiscal year from 2019 through 2024.

RESPONSE:

The projected balances of the Plant Outage Normalization deferrals are as follows:

December 2019	$930,694
December 2020	$3,229,384
December 2021	$2,424,872
December 2022	$3,606,757
December 2023	($1,647,755)

The projected balance of the deferral of Deferred Replacement Power not Recovered in FAC is $338,074 at each year-end from 2019-2023, as the portion of replacement power expense not recovered in FAC is assumed to match the amount recovered in base rates in the forecast periods. 2024 projected balances are not available, as the company does not forecast beyond a five-year period.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-069

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 166. Provide support that the zero-intercept method produces statistically unreliable results for Duke Kentucky for the following:

a. Pole cost allocation;

b. Conductor cost allocation; and

c. Transformer cost allocation.

RESPONSE:

The Company's statement in STAFF-DR-02-166 about statistically unreliable results was obtained from the NARUC Electric Utility Cost Allocation Manual (NARUC Manual). The NARUC Manual states on page 95:

"The minimum-intercept method can sometimes produce statistically unreliable results. The extension of the regression equation beyond the boundaries of the data normally will intercept the Y axis at a positive value. In some cases, because of incorrect accounting data or some other abnormality in the data, the regression equation will intercept the Y axis at a negative value. When this happens, a review of the accounting data must be made, and suspect data deleted."

The Company does not have enough data in the proper form and detail to prepare the zero-intercept models. As a result, the Company cannot provide the models in response to this data request.

PERSON RESPONSIBLE: James E. Ziolkowski

STAFF-DR-03-070

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 169, STAFF-DR-02-169_Attachment.xlsx, and its response to Staff's First Request, Item 54, STAFF-DR-01-054_Attachment_-_KPSE_Elec_SFRs_-_2019.xlsx, at tab "WPB-6's". Provide an itemized breakdown of lines 145, 146, and 147, tab "WPB-6's" of STAFF-DR-01-054_Attachment_-_KPSC_Elec_SFRs_-_2019.xlsx showing the itemized balances as of March 2020 and the monthly changes during the forecasted test year similar to the itemized break down of lines 144 and 148 provided in STAFF-DR-02-169_Attachment_xlsx.

RESPONSE:

See STAFF-DR-03-70 Attachment.

PERSON RESPONSIBLE: John R. Panizza

GL Account 282 - PP&E Deferred Taxes

		TEST PERIOD											
	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21
Beginning Balance	(178,931,393)	(180,774,157)	(182,584,391)	(184,399,120)	(186,229,809)	(188,067,697)	(189,870,691)	(191,646,518)	(193,431,299)	(195,218,656)	(197,087,411)	(198,904,953)	(200,719,136)
Book Depreciation	910,708	921,746	922,275	933,591	949,258	950,227	950,344	956,620	956,707	956,470	982,076	981,876	982,294
Tax Depreciation	(901,209)	(901,209)	(901,209)	(901,209)	(901,209)	(901,209)	(901,209)	(901,209)	(901,209)	(901,209)	(984,824)	(984,824)	(984,824)
Tax Gains/Losses	(180,000)	(162,935)	(158,881)	(180,791)	(207,623)	(179,221)	(156,149)	(175,774)	(183,513)	(240,152)	(123,640)	(123,640)	(123,640)
Tax Interest Capitalize	39,186	43,614	34,534	29,170	33,135	38,660	42,635	47,031	52,107	27,585	28,997	32,555	36,696
Tax Repairs	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,704,753)	(1,712,729)	(1,712,729)	(1,712,729)
Other	(6,696)	(6,696)	(6,696)	(6,696)	(6,696)	(6,696)	(6,696)	(6,696)	(6,696)	(6,696)	(7,421)	(7,421)	(7,421)
Total	(1,842,764)	(1,810,233)	(1,814,730)	(1,830,688)	(1,837,889)	(1,802,993)	(1,775,828)	(1,784,781)	(1,787,357)	(1,868,755)	(1,817,542)	(1,814,183)	(1,809,625)
Ending Balance	(180,774,157)	(182,584,391)	(184,399,120)	(186,229,809)	(188,067,697)	(189,870,691)	(191,646,518)	(193,431,299)	(195,218,656)	(197,087,411)	(198,904,953)	(200,719,136)	(202,528,761)
tiepoint to WPB-6	(180,774,158)	(182,584,391)	(184,399,121)	(186,229,809)	(188,067,698)	(189,870,692)	(191,646,519)	(193,431,300)	(195,218,657)	(197,087,412)	(198,904,954)	(200,719,137)	(202,528,761)

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 169.f., Attachment, page 22 of 23, and STAFF-DR-01-054_Attachment_-_KPSE_Elec_SFRs_-_2019, tab "WPB-6's" lines 144 and 164 of the spreadsheet for March 2020 through March 2021.

a. Explain why Duke Kentucky only applies the pro-rata method to the monthly ADIT changes in lines 145 and 146 of the spreadsheet, i.e., items in account 282, but does not apply the pro-rata method to lines 144, 145, and 148 of the spreadsheet, i.e., items in accounts 190, 281, and 283.

b. If Duke Kentucky contends that the pro-rata method should be applied to the monthly changes to accounts 190, 281, and 283 reflected in lines 144, 145, and 148 of the spreadsheet to calculate the amount of ADIT that should be included in rate base in the forecasted test year, explain why the monthly change in line 151 of the spreadsheet only reflects the monthly changes in lines 146 and 147 of the spreadsheet.

c. Confirm that to calculate the pro-rata amount of ADIT in account 282 that should be included in rate base in the forecasted test year, as Duke Kentucky attempts to do in lines 151 through 154 of the spreadsheet, that the sum of the amounts in cells F146 and F147 should be added to the sum of the pro-rata changes in cells G153 through R153. If this cannot be confirmed, provide the calculation. If this can be confirmed, provide a revised schedule in Excel spreadsheet format, with formulas intact and unprotected and all lines and columns accessible.

d. Confirm that to calculate the pro-rata amount of protected excess ADIT that should be included in rate base in the forecasted test year, as Duke Kentucky attempts to do in lines 161 through 164 of the spreadsheet, that the sum of the amount in cell F157 should be added to the sum of the pro-rata changes in cells G163 through R163. If this cannot be confirmed, provide the calculation. If this can be confirmed, provide a revised schedule in Excel spreadsheet format, with formulas intact and unprotected and all and columns accessible.

e. State whether Duke Kentucky contends that a 13-month average, the pro-rata method, or some other method should be used to calculate the extent to which the unprotected excess ADIT and the deferred tax assets and liabilities reflected in accounts 190, 281, and 283 at lines 144, 145, and 148 of the spreadsheet are included in rate base during the forecasted test year; explain the basis of your response; and provide a revised schedule reflecting those contentions in Excel spreadsheet format, with formulas intact and unprotected and all lines and columns accessible.

RESPONSE:

a. Treas. Reg. § 1.167(l)-1(a)(1) of the Income Tax Regulations provides that the normalization requirements for public utility property pertain only to the deferral of federal income tax liability resulting from the use of an accelerated method of depreciation for computing the allowance for depreciation under Section 167 and the use of straight-line depreciation for computing tax expense and depreciation expense for purposes of establishing cost of service and for reflecting operating results in regulated books of account. The regulations' normalization methods of accounting do not pertain to other book-tax timing differences with respect to state income taxes, construction costs, or any other taxes or items.

b. Please see the response for (a).

c. As per the response for STAFF-DR-03-071(a) pro-rata should be included in rate base in the forecasted test year. Line 146 and 147 represent cumulative balances therefore sum of F146 & F147 flow through to Row 154.

d. Line 157 represents cumulative balances therefore the sum of F157 flows through to Row 164.

e. The Company uses a 13-month average to calculate unprotected excess deferred income taxes. The pro-rata method is only required by IRS rules to be used for protected excess deferred income taxes. The 13-month average was used for unprotected excess deferred income taxes consistent with all other components of rate base where the Company is required to use a 13-month average.

PERSON RESPONSIBLE: John Panizza – a. thru d.
Sarah E. Lawler – e.

CONFIDENTIAL STAFF-DR-03-072
(As to Attachments (a)1 and 2 only)

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 53.

a. Explain why the credit spread for the current Sale of Accounts Receivables is five basis points higher in the instant case than in Case No. 2017-00321. Provide support for this higher credit spread.

b. Explain why the credit spread for the incremental interest over the 1-month LIBOR is approximately ten basis points higher in the instant case than in Case No. 2017-00321. Provide support for this higher credit spread.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET
(As to Attachments (a)1 and 2 only)

a. The accounts receivable securitization facility was amended and renewed for another 3-year term in December 2017 at the then-current market pricing of 72.5 basis points, 5 basis points higher than the 67.5 basis point credit spread from the 2013 facility amendment. See STAFF-DR-03-072(a) Confidential Attachment 1 and STAFF-DR-03-072(a) Confidential Attachment 2 for the Fourth Amended and Restated Fee Letter and Third Amended and Restated Fee Letter, respectively.

b. The average incremental interest charged by the participating banks over 1-month LIBOR from the 12-month period, June 2018 through May 2019, was approximately 22 basis points. See STAFF-DR-03-072(b) Attachment for this calculation. In Case No. 2017-0321, the estimate used for the incremental interest charged by the participating banks was between 10-12 basis points.

PERSON RESPONSIBLE: Christopher M. Jacobi

2019-00271

STAFF-DR-03-072(a)

CONFIDENTIAL ATTACHMENTS 1 AND 2 ARE BEING FILED UNDER SEAL

Month	1M LIBOR	Bank A	Bank B	Average Bank CP rate	Difference
Jun-18	2.0903%	2.3377%	2.3309%	2.3343%	0.2440%
Jul-18	2.0768%	2.3705%	2.3285%	2.3495%	0.2727%
Aug-18	2.1138%	2.3720%	2.3340%	2.3530%	0.2393%
Sep-18	2.2606%	2.3757%	2.3042%	2.3400%	0.0794%
Oct-18	2.3069%	2.4093%	2.3569%	2.3831%	0.0762%
Nov-18	2.3469%	2.4931%	2.5350%	2.5141%	0.1671%
Dec-18	2.5206%	2.6336%	2.8346%	2.7341%	0.2135%
Jan-19	2.5138%	2.7643%	2.8315%	2.7979%	0.2841%
Feb-19	2.4904%	2.8034%	2.8327%	2.8181%	0.3277%
Mar-19	2.4945%	2.7438%	2.7522%	2.7480%	0.2535%
Apr-19	2.4805%	2.6920%	2.7145%	2.7033%	0.2228%
May-19	2.4305%	2.6605%	2.6700%	2.6652%	0.2347%
					0.2179% average

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-073

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 171.b, Account 368, Line Transformer. Explain why the customer allocation decreased by almost 8 percent.

RESPONSE:

The transformer customer allocation is calculated in the cost of service study as the customer portion of the account 368 line transformers divided by the total gross plant account 368 line transformers.

The customer allocation decreased because:

- The total gross plant account 368 line transformer dollars increased from $56.3 million to $62.4 million.
- The customer portion (the numerator in the calculation) decreased from $18.2 million to $15.3 million. The customer portion is calculated by adjusting the current cost of a minimum size transformer by a transformer cost inflation index (Handy-Whitman Index) and multiplying the inflation-adjusted costs by the number of transformers installed in each year. The 2018 Handy-Whitman Index for transformers is $995. The 2016 index cost was $883. This large change in the inflation index caused older transformers to have less weighting in the numerator of the allocation factor.

These two changes (decrease in the numerator and increase in the denominator) caused the allocation factor to decrease.

PERSON RESPONSIBLE: James E. Ziolkowski

STAFF-DR-03-074

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 172.

a. Provide the total annual amortization of excess protected ADIT using the average rate assumption method for the years 2020 and 2021 (as opposed to estimating it by carrying forward to the 2018 amortization amount), and provide workpapers showing the calculation in excel spreadsheet format with formulas intact.

b. If Duke Kentucky is not able to provide the total annual amortization of excess protected ADIT using the average rate assumption method for the years 2020 and 2021 as requested in subpart a. of this request, provide the total amortization of excess ADIT for the years 202 and 2021 using the "ALTERNATIVE METHOD" described in Tax Cuts and Jobs Act,[1] and provide workpapers showing the calculations in excel spreadsheet format with formulas intact.

RESPONSE:

a. Duke Kentucky has not attempted to calculate a forecasted ARAM for 2020 and 2021. Those calculation are done in PowerTax and PowerTax is not used as a forecasting tool for Duke Kentucky. We know ARAM will change but Duke Kentucky decided to use the 2018 ARAM as a tool for estimating the forecast.

[1] Pub. L. No. 115-97, § 13001, 131 Stat 2054, 2099-2100 (2017).

b. Duke Kentucky has not made any calculations under the "ALTERNATIVE METHOD" as ARAM is required by the IRS normalization rule for Duke Kentucky.

PERSON RESPONSIBLE: John R. Panizza

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-075

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 172.d.

a. Explain how Duke Kentucky's completion of its 2017 tax return reduced the amortization of excess protected ADIT using the average rate assumption method in 2018 from $90,773.22 per month in Case No. 2017-00321 to $36,580.00 per month in this case despite the fact that Duke Kentucky's calculation of the total excess protected ADIT increased from $34,912,797.00 in Case No. 2017-00321 to $47,193,845.00.

b. State whether the amortization rate of $438,961 per year (or $36,580.00 per month) calculated for 2018 in this case is the actual amortization rate permitted in 2018 using the average rate assumption method or if the rate provided in this case includes a true-up for past amortization at a rate faster than permitted by the average rate assumption method.

c. If the amortization rate of $438,961 per year (or $36,580.00 per month) for 2018 includes a true-up for past amortization at a rate faster than permitted by the average rate assumption method, provide the actual amortization rate for excess protected ADIT for 2018 using the average rate assumption method.

d. Provide the actual monthly amortization of excess protected and unprotected ADIT that Duke Kentucky recorded from April 1, 2018, through March 31, 2019, and to the extent that those monthly amounts differ from the amortization included in Duke Kentucky's current base rates, explain any impact on the current revenue requirement.

RESPONSE:

a. Actual ARAM calculations are performed on every record in PowerTax. Just because total EDIT increased does not necessarily mean that total ARAM will increase. The initial estimate would have included estimates for many items such as book depreciation, tax depreciation, and retirements. Once we get actuals all the amounts will naturally change.

b. The $35,580.00 does not include any amount for a true-up.

c. The $35,580.00 does not include any amount for a true-up.

d. The actual monthly amortization of excess protected and unprotected ADIT that Duke Kentucky recorded from April 1, 2018, through March 31, 2019 was $438,962 and $2,991,425 respectively and during that period the amortization in current base rates is $1,168,705 and $3,303,278 respectively.

PERSON RESPONSIBLE: John R. Panizza – a. thru c., d. (actual expenses)
Sarah E. Lawler – d. (current base rates)

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-076

REQUEST:

Refer to Duke Kentucky's response to Staff's Second Request, Item 172.f, STAFF-DR-02-172(f)_Attachment.xlsx.

a. Provide a brief description of each column heading in the "DEK Electric" tab of the spreadsheet, e.g., DEFTAX_RATE_BEG_EFFECT_DATE, BEG_FAS109_AT_CURRENT_RATE, etc.

b. Identify and describe each type of item that generated the excess deferred tax assets included as part of the net excess protected ADIT for Duke Kentucky in the spreadsheet.

c. Provide a version of STAFF-DR-02-172(f)_Attachment.xlsx, tab "DEK Electric" with all formulas intact showing how the FED_ARAM_NOT_FLOWTHRU column for each item is calculated from the timing differences for each item.

d. If STAFF-DR-01-172(f)_Attachment.xlsx, tab "DEK Electric" was generated by a program and the program is not able to produce the spreadsheet with formulas intact, in lieu of providing the spreadsheet with all formulas intact, explain how Duke Kentucky calculated the FED_ARAM_NOT_FLOWTHRU for an item and show how it calculated the FED_ARAM_NOT_FLORTHRU for the items on line 452, line 813, and line 10054 of tab "DEK_Electric" the spreadsheet, including all formulas.

RESPONSE:

a. This file is a data dump of MANY fields out of PowerTax. I'm describing some of the fields below. Duke Energy Kentucky does not currently have a description for every field in the data dump. Duke Energy Kentucky would have to get the software vendor (PowerPlan) to provide descriptions for some of the fields in the file. If there are others where a description is desired, please request.

DEFTAX_RATE_BEG_EFFECT_DATE - This field shows the beginning effective date that the deferred tax rate was first entered or changed in the system.

DEFTAX_RATE_END_EFFECT_DATE - This field shows the last effective date for the deferred tax rate.

R257_FAS109_BEG - This field shows the PowerTax Calculation of deferred taxes at the rate effective for the prior year. (35%)

BEG_FAS109_AT_CURRENT_RATE - This field shows the PowerTax Calculation of deferred taxes restated at the rate effective for the current year. (21%)

RATE_CHG_IMPACT_BEG_FAS109 - This field shows the PowerTax EDIT amount (Rate change impact on the Regulatory Liability)

Sum of R257_BEG_REG_B4_GROSSUP - This shows the beginning balance of the Regulatory Asset/Liability for Excess Deferred Taxes

Sum of R257_NET_CHG_REG_B4_GROSSUP - This shows the net change in the balance of the Regulatory Asset/Liability for Excess Deferred Taxes

Sum of R257_END_REG_B4_GROSSUP - This shows the ending balance of the Regulatory Asset/Liability for Excess Deferred Taxes

FED_ARAM_NOT_FLOWTHRU - This field shows the PowerTax calculated ARAM amount.

b. Protected deferred taxes for PP&E result from differences arising from book depreciation versus tax depreciation. These differences can be categorized in 2 ways. The 1st category is difference resulting from depreciation methods. Book accounting normally uses a straight-line method but tax often uses accelerated methods such as MACRS depreciation and bonus depreciation. The 2nd category is difference in lives when book accounting chooses to depreciate an asset over a longer or shorter period of years than tax depreciates the asset. All differences resulting from method/life differences are considered Protected by the IRS.

c. This file is a dump of data out of PowerTax and there is no spreadsheet that shows all the calculations for each of the columns.

d. If you take the R257_End_Reg_B4_Grossup column of $-47,511,292.99 and subtract the R257_Beg_Reg_B4_Grossup column of $-134,546.77 you get the net change in the regulatory liability of $-47,376,746.23. Then subtract out the change in the regulatory liability caused by the rate change (Rate_Chg_Impact_Beg_FAS109 column) of $47,815,707.33 which gives you your ARAM amortization amount for the current year of $438,961.11. The Regulatory Asset/Liability is simply the difference between APB11 deferred tax balance and the FAS109 deferred tax balance.

PERSON RESPONSIBLE: John R. Panizza

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-077

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request for Information (Attorney General's First Request), Item 16. Explain why Duke Kentucky is not amortizing state excess ADIT.

RESPONSE:

Duke Energy Kentucky will start amortizing state excess ADITs for its electric business upon receiving an order in this instant case approving the amortization it is proposing in this case.

PERSON RESPONSIBLE: John Panizza

STAFF-DR-03-078

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request, Items 39, 41, and 46. To the extent that these responses identify errors in the base period or forecasted period, explain the revenue requirement impact.

RESPONSE:

To the extent that Duke Energy Kentucky' responses to AG-DR-01-041 and AG-DR-01-046 identified errors, there was no impact to the test year revenue requirement. More specifically, with regards to AG-DR-01-041, the identified error, "Base Period inadvertently excluded Unproductive Labor Allocation," was an error which only impacted the base period. The test period remained accurately stated. For AG-DR-01-046, certain costs from Accounts 510000, 551000, & 920000 in the test year were instead consolidated in Account 500000. As these costs were still included in the test year, although in Account 500000 despite not being separated out in the other three Accounts, there was no test year revenue requirement impact.

The error identified in response to AG-DR-01-039 would increase the revenue requirement by $926,248. See STAFF-DR-03-085 Attachment for further detail on error identified in AG-DR-01-039.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-079

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request, Items 41 and 93. Explain how the increase in Customer Connect program cost relate to the decreased Customer Service and Information expenses.

RESPONSE:

Customer Connect program labor expenses are included in Customer Records and Collections expenses rather than Customer Service and Information expenses. In addition, the two requests relate to different comparisons. Attorney General's First Request, Item 41 relates to a comparison of labor related payroll costs between the Base Period and the Test Period while Attorney General's First Request, Item 93 relates to a comparison of certain expenses between the Company's 2017 General Rate Case and the current case.

PERSON RESPONSIBLE: Christopher M. Jacobi

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-080

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request, Items 81. Explain why the change in account referenced in the response is appropriate.

RESPONSE:

Please see response to STAFF-DR-03-026 related to the accounting for Sale of Accounts Receivable.

PERSON RESPONSIBLE: Christopher M. Jacobi

STAFF-DR-03-081

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request, Items 106(c). Identify the Kentucky law or regulation that gives utilities the authority to charge fees that are meant as a deterrent instead of being cost-based.

RESPONSE:

Duke Energy Kentucky objects to the request to the extent that it calls for a legal conclusion. Without waiving said objection, Duke Energy Kentucky states that KRS 278.030 provides that a utility's rates must be "fair, just and reasonable." KRS 278.170 provides that a utility's rates shall not include any "unreasonable prejudice or disadvantage." In *Public Service Comm'n of Kentucky v. Com. of Kentucky*, 320 S.W.3d 660 (Ky. 2010), the Kentucky Supreme Court affirmed that an economic development rate tariff was valid on the basis that it was both reasonable and lawful under the foregoing statutory authorities even though the customer class for whom the tariff was intended would receive service at a discount to cost based rates. The policy behind this decision was to incentivize investment and the creation of jobs within the Commonwealth of Kentucky. The basis for this decision was grounded in the fact that the Court found a rate distinction to be both lawful and reasonable. In this case, it should be recognized that certain behaviors – including tampering with electric utility equipment – should be discouraged as they tend to create safety risks and costs which are unnecessary and are generally unlawful. So long as the tariffed rate that creates a disincentive to such behavior is itself reasonable, there is no legal distinction between it and an economic development rider that incentivizes desired conduct.

PERSON RESPONSIBLE: Legal

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-082

REQUEST:

Refer to Duke Kentucky's response to Northern Kentucky University's First Request for Information (NKU's First Request), Item 8. Explain whether this response indicates that Duke Kentucky proposes to defer costs that exceed revenues for the EV Fast Charging Program to a regulatory asset.

RESPONSE:

The Company is not requesting authority to defer costs that exceed revenues for the EV Fast Charging Program to a regulatory asset. In the unlikely situation that costs exceed revenues and the difference is substantial the Company would seek authority to defer those costs through a separate application.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-083

REQUEST:

Refer to Duke Kentucky's response to NKU's First Request, Item 13. State whether ancillary service market revenues will offset the revenue requirement of the proposed battery and provide supporting calculations.

RESPONSE:

Please see STAFF-DR-02-079(b) Confidential Attachment tab "BCA" and STAFF-DR-02-086 Attachment. The revenue requirement is expected to be approximately \$350K in proposed rates and the ancillary revenues are expected to be approximately \$500K per year. Because the project is forecasted to be placed in-service in December 2020, only a portion of the plant in-service is included in rate base in this rate case resulting in the approximate \$350K of revenue requirement in this case. However, the revenue requirement would increase in a future rate case when all of the plant is in rate base.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-084

REQUEST:

Separately identify the total amount recorded as a "repair" expense for tax purposes but capitalized for book purposes in 2016, 2017, 2018, the base period, and the forecasted test period, including projected amounts in future periods.

RESPONSE:

ACTUALS For Repairs 2016, 2017, and 2018

2016 - $22,041,637
2017 - $30,200,626
2018 - $45,779,320

Base period is December 2018 – November 2019.
The January 2019 thru November 2019 Forecasted Repairs are $75,059,000.

Test Period is April 2020 – March 2021.
The Forecasted Repairs for this period are $82,176,000.

PERSON RESPONSIBLE: John R. Panizza

Duke Energy Kentucky
Case No. 2019-00271
Staff's Third Set Data Requests
Date Received: November 8, 2019

STAFF-DR-03-085

REQUEST:

Provide a revised revenue requirement calculation that incorporates all corrections or revisions identified through discovery responses and list any changes made.

RESPONSE:

See STAFF-DR-03-085 Attachment for a revised revenue requirement calculation that incorporates all corrections and revisions identified through discovery responses.

PERSON RESPONSIBLE: Sarah E. Lawler

Reference	Summary	Change within the Revenue Requirements Model	Impact Net of Gross Up to Revenue Requirement
Revenue Requirement Deficiency as filed			**$ 45,634,456**
AG-DR-01-039	Inadvertently excluded intercompany A&G rent expense in Account 931008 from the test period	$ 914,966	$ 926,248
AG-DR-02-005	The Noncurrent After Tax DTA for Solar ITC, EPRI, and R&D Credits should have been excluded from rate base.	$ (3,017,307)	$ (250,336)
AG-DR-02-32(e)	FERC Order No. 494 refunds that customers were charged RTEP. Refunds associated with this period were $260,022. Company proposes to amoritze this refund over a period of five years.	$ (52,004)	$ (52,106)
Revenue Requirement Deiciency as revised			**$ 46,258,262**

Note: as it relates to AG-DR-02-005, rate base should have been reduced by $3,017,307 resulting in a revenue requirement change of ($250,336)