STAFF-DR-02-001

REQUEST:

Refer to the Application, Volume 1, Tab 27.

a. Explain whether the capital expenditures budget reflects both the electric and gas operations of Duke Kentucky. If the budget reflects electric and gas operations, resubmit the capital expenditures budget separating the electric and gas operations.

b. Provide a comparison of the three-year projected capital expenditures in Case No. 2006-00172[1] with the actual capital expenditures for those years.

RESPONSE:

a. The capital expenditures budget on Volume 1, Tab 27 of the Application reflects activity for electric operations only.

b. See attachment STAFF-DR-02-01b

PERSON RESPONSIBLE: Robert H Pratt

[1] Case No. 2006-00712. *Application of the Union Light, Heat and Power Company d/b/a Duke Energy Kentucky for an Adjustment of Electric Rates* (Ky. PSC Dec. 21, 2006).

Duke Energy Kentucky
Case No. 2017-00321
Major Construction Projects
Comparison to Case No. 2006-00172
Years 2006-2008

Duke Energy Kentucky Case No 2006-00172 Projected Capital Expenditures

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs including AFUDC 2006	2007	2008	Estimated Costs Excluding AFUDC 2006	2007	2008
1	EB201294 - Install Lndfl Cell P-15 & P-16	Jan-05	Dec-06	$ 4,611,059	$ 22	$ -	$ 4,487,866	$ -	$ -
2	MF3056 - MF5-6 LNCFSII	Dec-04	Jun-06	3,876,634	-	-	3,844,070	-	-
3	WG0191 - WGS-CT1 Major "C" Overhaul #1	Dec-04	Jun-06	3,939,060	-	-	3,663,527	-	-
4	WG0244 - WGS-CT4 Major "C" Overhaul #2	Jan-07	Jun-08	-	2,748,667	14,616,905	-	2,616,698	14,278,773
5	310ZNB - ZULH&P NEW BUSINE55 SOUTH AREA	Jan-06	Dec-50	4,975,959	5,094,011	5,144,598	4,975,959	5,094,011	5,144,598
	TOTAL			$ 17,402,712	$ 7,842,700	$ 19,761,503	$ 16,971,423	$ 7,710,709	$ 19,423,371

Duke Energy Kentucky Actual Capital Expenditures

Line No.	Project ID/Description	Actual Start Date	Actual or Projected Completion Date	Actual Costs including AFUDC 2006	2007	2008	Actual Costs Excluding AFUDC 2006	2007	2008
1	EB201294 - Install Lndfl Cell P-15 & P-16	Sep-05	Apr-07	$ 3,043,266	$ 24,337	$ -	$ 3,008,360	$ 24,337	$ -
2	MF3056 - MF5-6 LNCFSII	5ep-05	Aug-06	4,542,098	34,009	(60,633)	4,525,657	34,009	(60,633)
3	WG0191 - WGS-CT1 Major "C" Overhaul #1	Sep-05	Mar-07	11,369,536	66,717	(148,763)	11,007,961	66,717	(148,763)
4	WG0244 - WGS-CT4 Major "C" Overhaul #2	Jul-07	May-09	-	1,848,807	3,931,011	-	1,845,010	3,865,467
5	310ZNB - ZULH&P NEW BUSINESS SOUTH AREA	Jan-06	Dec-50	7,010,247	5,627,477	2,441,576	6,997,809	5,623,798	2,440,904
	TOTAL			$ 25,965,147	$ 7,601,347	$ 6,163,191	$ 25,539,787	$ 7,593,871	$ 6,096,974

Variance

Line No.	Project ID/Description	Costs including AFUDC 2006	2007	2008	Costs Excluding AFUDC 2006	2007	2008
1	EB201294 - Install Lndfl Cell P-15 & P-16	$ 1,567,793	$ (24,315)	$ -	$ 1,479,506	$ (24,337)	$ -
2	MF3056 - MFS-6 LNCF5II	(665,464)	(34,009)	60,633	(681,586)	(34,009)	60,633
3	WG0191 - WGS-CT1 Major "C" Overhaul #1	(7,430,476)	(66,717)	148,763	(7,344,433)	(66,717)	148,763
4	WG0244 - WGS-CT4 Major "C" Overhaul #2	-	899,860	10,685,894	-	771,688	10,413,306
5	310ZNB - ZULH&P NEW BUSINESS SOUTH AREA	(2,034,288)	(533,466)	2,703,022	(2,021,850)	(529,787)	2,703,694
	TOTAL Underspend/(Overspent)	$ (8,562,435)	$ 241,353	$ 13,598,312	$ (8,568,364)	$ 116,838	$ 13,326,397

Duke Energy Kentucky
Case No. 2017-00321
Major Construction Projects
Comparison to Case No. 2006-00172
Years 2006-2008

Duke Energy Kentucky Case No 2006-00172 Projected Capital Expenditures

Line No.	Project ID/Description	Actual or Projected Start Date	Projected Completion Date	Estimated Costs including AFUDC			Estimated Costs Excluding AFUDC		
				2006	2007	2008	2006	2007	2008
1	Sum of all projects not included on FR 10(9)(f)			$ 24,475,848	$ 22,920,696	$ 19,791,002	$ 24,125,258	$ 22,429,331	$ 19,214,095

Duke Energy Kentucky Actual Capital Expenditures

Line No.	Project ID/Description	Actual Start Date	Actual or Projected Completion Date	Actual Costs including AFUDC			Actual Costs Excluding AFUDC		
				2006	2007	2008	2006	2007	2008
1	Sum of all projects not included on FR 10(9)(f)			$ 35,466,741	$ 48,284,308	$ 52,818,881	$ 35,266,289	$ 48,072,844	$ 52,106,758

Variance

Line No.	Project ID/Description	Costs including AFUDC			Costs Excluding AFUDC		
		2006	2007	2008	2006	2007	2008
1	Sum of all projects not included on FR 10(9)(f)	$ (10,990,893)	$ (25,363,612)	$ (33,027,879)	$ (11,141,031)	$ (25,643,513)	$ (32,892,663)

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-002

REQUEST:

Refer to the Application, Volume 1, Tab 28.

a. Explain whether the capital expenditures budget reflects both the electric and gas operations of Duke Kentucky. If the budget reflects electric and gas operations, resubmit the capital expenditures budget separating the electric and gas operations.

b. Provide a comparison of the three-year projected capital expenditures in Case No. 2006-00172 with the actual capital expenditures for those years.

RESPONSE:

a. The capital expenditures budget on Volume 1, Tab 28 of the Application reflects activity for electric operations only.

b. See attachment STAFF-DR-02-01b. Note that actuals were tied to the FERC Form 1 cash flows for annual periods 2006, 2007, and 2008 less the actuals for specific projects provided for request STAFF-DR-02-01b. This would include both Electric and Gas capex.

PERSON RESPONSIBLE: Robert H Pratt

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-003

REQUEST:

Refer to the Application, Volume 1, Tab 29.

a. Refer to page 1 of 13.

   1) Explain the decrease in Electric Revenue from 2017 through 2019.

   2) Explain the large increase in Gas Revenue in 2019.

   3) Explain the large decrease in Other Revenue in 2018.

   4) Explain why Gas Purchased does not increase significantly in 2019.

   5) Explain why Operation and Maintenance expense decreases significantly in 2019.

   6) Explain the fluctuation in Other Income from 2017 through 2019.

b. Refer to page 3 of 13.

   1) Explain why there are no Dividends on common stock for 2017 through 2019.

   2) Provide the amount of Dividends on common stock for the five-year period ended December 31, 2016.

   3) Provide a comparison of the projected and actual Dividends on common stock in the three-year period for projected cash flows in Case No. 2006-00172.

c. Refer to page 5 of 13. Provide a comparison of the projected and actual kW Demand – Coincident Peak and kWh Sales for the three-year period for the Load Forecast in Case No. 2006-00172.

d. Refer to page 8 of 13.

1) Explain why the number of employees does not decrease from 2017 through 2019 due to the deployment of its Advanced Metering Infrastructure ("AMI") project.

2) Explain whether Duke Kentucky anticipates any changes in the number of its employees after the test year in 2019. If so, provide an estimate of the number of employees and the impact on cost for O&M and capital.

e. Refer to page 12 of 13.

1) Identify and explain the basis of the Customer Forecast.

2) Provide the three-year Customer Forecast conducted in Case No. 2006-00172. Provide also the actual number of customers for the three-year period used in Case No. 2006-00172 in the same format as set forth in Tab 29 of the Application.

RESPONSE:

a.

1) The decrease is primarily due to lower prices for coal in 2019 versus 2018 and versus 2017. The forecast assumes coal cost of $21.96/mwh in 2017 and coal cost of $20.63/mwh in 2019. This accounts for approximately half of the total decrease. In addition to lower fuel costs, the forecast

includes reduced revenues for the DSM rider in 2019 versus 2018 and versus 2017. This accounts for approximately half of the total decrease.

2) This forecast assumes a gas rate case is filed in 2018 with new rates going into effect in 2019. This is the primary driver for the increase from 2018 to 2019.

3) Other Revenue in 2017 includes $1M for miscellaneous revenue target. This item does not continue in the forecast beyond 2017.

4) Gas Purchased does not increase significantly in 2019 as the change in gas supply and gas cost per mcf are not significant. The increase in Gas Revenue in 2019 is not driven by gas supply or gas cost per mcf.

5) The reduction in 2019 Operations and Maintenance expense is explained by reduced Fossil outages versus 2018.

6) The fluctuation in Other Income from 2017 through 2019 is explained by the fluctuation in Allowance for Funds Used During Construction (AFUDC) which is driven by the timing of capital expenditures and closings to plant in-service.

b.

1) The Company targets an overall capital structure to ensure high credit quality, while minimizing its overall cost of capital. The forecast assumes the Company's capital needs are financed in a manner to maintain this balanced capital structure. The Company's earnings are forecasted to be retained at the Company (versus having dividends) in 2017 and 2018 in order to maintain the desired equity component of the capital structure. Infusions from parent of

$10 million and $49.5 million are forecasted for 2017 and 2018, respectively, in addition to the retained earnings. There are $14.5 million of dividends forecasted for 2019. The infusions and dividends are reflected in the Change in contributed capital row on the projected cash flow statement in Volume 1, Tab 29.

2)

$ in Thousands	**Dividends on common stock**
2012	$10,000
2013	$40,001
2014	$0
2015	$55,000
2016	$10,001

3)

Dividends on common stock ($ in Thousands)	**Projected in Case No. 2006-00172**	**Actuals**
2006	$0	$0
2007	$5,300	$0
2008	$10,960	$30,000

c. Table 3-C from the 2011 Kentucky IRP gives a comparison of actual versus forecast for 2006-2008 for the DEK system. These numbers—which should be interpreted in the context of the recession of 2007-2009—are presented below, with all figures on an "after energy efficiency" basis.

	Energy - MWH		Internal Peak - MW	
Year	**Actual**	**Forecast**	**Actual**	**Forecast**
2006	4,248,717	4,134,466	883	916
2007	4,564,528	4,189,016	921	929
2008	4,347,644	4,226,376	860	938

d.

1) In accordance with the Company's budgeting process, headcount data is not budgeted. Labor budgets are determined based on salary dollars. Given that, in preparing the headcount estimates referenced on page 8 of 13, an assumption was made that there would be no material changes from headcount as of December 31, 2016. The Company did however include cost savings in the test period via the proforma adjustment D-2.26 that contemplated a lower number of meter reading employees. These cost savings were based on a reduction of 2 Duke Energy Kentucky meter reading employees in 2018 and 10 meter reading employees in 2019.
2) The cost savings included in proforma adjustment D-2.26 were based on a reduction of 10 meter reading employees in 2019 and 14 meter reading employees in all years projected beyond 2019.

e.

1) The customer forecast is estimated based on the change in population of the counties most closely representing the Duke Energy Kentucky service area. This model—which is based on monthly data—adjusts for the normal monthly cycle on which customers ebb and flow throughout the year. Some time series corrections are also applied to reduce the chances

of falsely identifying the impact of population on this forecast. Over a ten year period from 2006-2016, the model performs quite well in forecasting the number of customers, with an average error of under 0.11%.

2) Historical Figures for customers for 2006-2008 are compared with actuals in the Attachment STAFF-DR-02-003e.xlsx

PERSON RESPONSIBLE: Robert H. Pratt (a)
Jack Sullivan (b)
Benjamin Passty (c) (e)
Robert H. Pratt/Don Schneider (d)

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Customer Forecast 2006-2008

Line No.	Description	2006	2007	2008
1	Residential	118,154	119,597	120,672
2	Commercial	13,119	13,364	13,546
3	Industrial	397	397	397
4	Other	1,277	1,297	1,307
5	Total Electric Retail	132,947	134,655	135,922
6	Residential	86,244	87,997	88,867
7	Commercial	6,936	6,958	7,063
8	Industrial	237	235	238
9	Other	382	381	386
10	Total Full Requireme	93,799	95,571	96,554
11				
12	Transportation			
13	Commercial	24	24	24
14	Industrial	45	45	45
15	Other	9	9	9
16	Total Transportatior	78	78	78
17				
18	Total Gas Retail (Line	93,877	95,649	96,632

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Actual Customer Count at Year-End 2006-2008

Line No.	Description	2006	2007	2008
1	Residential	118,642	119,245	119,997
2	Commercial	13,184	13,443	13,347
3	Industrial	391	393	384
4	Other	1,318	1,333	1,361
5	Total Electric Retail	133,535	134,414	135,089
6	Residential	86,885	87,804	87,954
7	Commercial	7,133	7,227	7,223
8	Industrial	238	231	221
9	Other	379	380	368
10	Total Full Requireme	94,635	95,642	95,766
11				
12	Transportation			
13	Commercial	20	19	20
14	Industrial	34	35	36
15	Other	7	9	23
16	Total Transportatior	61	63	79
17				
18	Total Gas Retail (Line	94,696	95,705	95,845

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-004

REQUEST:

Refer to the Application, Volume 9, Tab 42. Provide the following information for any of the Duke Energy Business Services ("DEBS:") and other affiliated entities' costs directly assigned or allocated to Duke Kentucky, as well as other requested information.

a. As reflected in the test-year level of expenses proposed by Duke Kentucky, provide the following as it relates to salaries either directly assigned or allocated to Duke Kentucky by another DEBS entity.

    1) By DEBS Department, the total salary amount along with the number of hours associated with the salary cost and associated incentive pay broker down by each incentive pay program, including any stock option plans in effect during any month of the test year.

    2) By any other Duke Energy Corporation ("Duke Energy") subsidiary, provide the name of the subsidiary and the department along with the total salary amount and associated incentive pay, including any stock option plans, along with the number of hours associated with the salary, incentive pay, and any stock option plans costs.

b. The DEBS Charge billed to Duke Kentucky for the 12 months ended November 2012 through November 2017.

c. The number of DEBS employees at November 2012 through November 2017.

d. Duke Kentucky's peak demand (date and time) for each 12-month period from November 2012 through November 2017.

e. Duke Kentucky's kWh sales (by customer class residential, commercial and industrial) for each 12-month period from November 2012 through November 2017.

f. The level of Duke Kentucky employees for each 12-month period from November 2012 through November 2017.

g. Clarification as to whether the costs are allocated based on the number of Duke Kentucky employees. Duke Kentucky kWh sales, or Duke Kentucky's peak demand. If so, identify each.

h. Clarification as to whether Duke Kentucky has made an adjustment to the test-year level of DEBS costs to reflect the most recent three-, five-, or ten-year trend in the number of employees, the kWh sales, and the Duke Kentucky's peak demand. If so, identify each adjustment.

i. If the answer to h. above is negative, explain why no test-year adjustment was made in Duke Kentucky's proposed test-year level of DEBS Service costs.

RESPONSE:

a. Please see "STAFF-DR-02-004a Attachment".

b. Please see "STAFF-DR-02-004 b,c,d,f,g Attachment" For direct and allocated charges from DEBS for the requested periods.

c.

Active Workers Only
Excludes Workers on LTD
Excludes Contingent Workers

	DEBS
Nov - Year	
2012	6,769
2013	5,522
2014	7,244
2015	7,767
2016	7,336
2017	7,366

Note: This is the total count of active workers. They may or may not have charged to Kentucky Business Units

d. Please see below:

Duke Energy Kentucky Annual Peak Demand				
Start Date	End Date	Date of Annual Peak Demand	Hour Ending (EST)	Annual Peak Demand (MW)
11/1/2012	10/31/2013	7/8/2013	17	858
11/1/2013	10/31/2014	1/6/2014	20	860
11/1/2014	10/31/2015	7/29/2015	13	803
11/1/2015	10/30/2016	7/25/2016	14	855
11/1/2016	10/30/2017	7/20/2017	18	817

Source: Energy Accounting System (TGIS), ULHP Load with losses as of 11-8-17. DEK annual peak demand inclusive of transmission and distribution losses and Longbranch.

e. Please see STAFF-DR-02-004e Attachment. October 2017 data will not be available until mid-November.

f.

Active Workers Only
Excludes Workers on LTD
Excludes Contingent
Workers

	DE Kentucky Payroll Company			
Nov - Year	Managers	Supervisors	Union	Non-Union Hourly
2012	1	6	186	1
2013		6	172	4
2014	1	4	156	5
2015	1	5	181	5
2016	1	5	179	5
2017	2	9	188	5

g. Please see "STAFF-DR-02-004-b-g.xlsx". This file includes all allocation amounts to Kentucky including, number of employees, sales, and peak load.

h. No.

i. No adjustments were made to the test period levels of DEBS employees, kWh sales or KW demand level because the Company believes that the levels used in the forecast accurately represent current values that should be used for ratemaking purposes.

PERSON RESPONSIBLE: Jeff Setser (a) (b) (c) (f) (g)
John Swez (d)
James E. Ziolkowski (e)
Robert H. Pratt (h) (i)

Commission Staff' Second Request: # 4a (1), (2)

4. Refer to the Application, Volume 9, Tab 42. Provide the following information for any of the Duke Energy Business Services ("DEBS") and other affiliated entities' costs directly assigned or allocated to Duke Kentucky, as well as other requested information.

a. As reflected in the test-year level of expenses proposed by Duke Kentucky, provide the following as it relates to salaries either directly assigned or allocated to Duke Kentucky by another DEBS entity.

(1) By DEBS Department, the total salary amount along with the number of hours associated with the salary cost and associated incentive pay broken down by each incentive pay program, including any stock option plans in effect during any month of the test year.

(2) By any other Duke Energy Corporation ("Duke Energy") subsidiary, provide the name of the subsidiary and the department along with the total salary amount and associated incentive pay, including any stock option plans, along with the number of hours associated with the salary, incentive pay, and any stock option plans costs.

Response:

See the below table for salary cost and associated incentive pay program cost for Duke Kentucky and its affiliates. Amounts extracted from the company's general ledger system (budget) for the test period. Note, related hours are unavailable in the company's general ledger system.

Total Duke Energy Kentucky (Consolidated)

Company	Department	Salary Cost	Short-term Incentive	Long-term Incentive	Total
DE Carolinas	Coal Combustion Products	$ 153,803	$ 16,177	$ -	$ 169,980
	Corporate Groups	1,635	172	-	1,807
	Customer Operations	589,973	61,840	-	651,813
	Fossil Hydro Operations	552,522	59,239	-	612,161
	Gas Operations	96,438	10,157	-	106,595
	Grid Solutions	15,969	1,679	-	17,649
	Market Solutions	579,817	80,955	-	660,873
	Operations Support	402,881	42,110	-	444,991
	Other Departments	582,693	56,764	-	639,457
	Regulated Utilities Other	66,339	6,988	-	73,327
	Renewable Generation	224,847	23,681	-	248,528
	Transmission	27,367	2,876	-	30,243
Service Company	Coal Combustion Products	290,074	33,419	17,762	341,255
	Corporate Groups	5,186,101	593,559	1,842,339	7,622,489
	Customer Connect	827,241	72,133	13,021	710,395
	Customer Operations	2,071,703	208,857	-	2,280,560
	Distribution Operations	992,215	114,245	-	1,106,460
	Fossil Hydro Operations	5,581,273	688,178	17,960	6,687,411
	Gas Operations	1,200,193	130,189	6,888	1,337,270
	Grid Solutions	2,189,149	256,222	-	2,445,371
	Market Solutions	634,462	73,018	-	707,478
	Operations Support	3,193,020	352,804	-	3,545,824
	Other Departments	5,279,907	536,049	166	5,816,142
	Regulated Utilities Other	1,010,295	116,147	11,755	1,138,197
	Renewable Generation	42,107	4,858	-	46,964
	Transmission	2,395,496	176,577	-	2,572,074
DE Ohio	Customer Operations	1,137,559	87,677	-	1,225,236
	Distribution Operations	74	-	-	74
	Gas Operations	128,861	7,632	-	136,493
	Market Solutions	29,951	3,156	-	33,106
	Operations Support	174,589	11,939	-	186,528
	Other Departments	14,173	1,488	-	15,661
DE Indiana	Coal Combustion Products	493,660	52,010	-	545,669
	Customer Operations	35,917	3,761	-	39,688
	Fossil Hydro Operations	374,907	39,499	-	414,406
	Gas Operations	10,267	1,082	-	11,348
	Market Solutions	72,094	7,579	-	79,672
	Operations Support	46,150	4,846	-	50,996
	Other Departments	69,581	7,331	-	76,912
	Regulated Utilities Other	21,418	2,257	-	23,674
DE Kentucy	Customer Operations	990,262	40,469	-	1,030,731
	Distribution Operations	5,704,979	194,478	-	5,899,456
	Fossil Hydro Operations	8,238,581	237,966	-	8,476,547
	Gas Operations	12,898,992	1,286,425	-	14,185,417
	Grid Solutions	3,612,507	390,018	-	4,002,525
	Market Solutions	185,013	11,038	-	196,051
	Operations Support	525,867	55,266	-	581,134
	Transmission	22,501	946	-	23,447
DE Progress	Coal Combustion Products	432	45	-	477
	Corporate Groups	58	6	-	64
	Customer Operations	58,910	6,182	-	65,092
	Fossil Hydro Operations	119,665	12,574	-	132,239
	Gas Operations	16,309	1,717	-	18,027
	Grid Solutions	5,548	584	-	6,132
	Market Solutions	166,333	17,497	-	183,830
	Operations Support	80,823	8,488	-	89,311
	Other Departments	141,228	14,631	-	155,859
	Regulated Utilities Other	33,969	3,572	-	37,541
	Transmission	2	0	-	2
DE Florida	Coal Combustion Products	2,054	216	-	2,270
	Customer Operations	16,152	1,699	-	17,851
	Distribution Operations	26,456	4,090	-	30,547
	Fossil Hydro Operations	23,709	2,490	-	26,199
	Gas Operations	1,528	160	-	1,688
	Market Solutions	16,866	1,765	-	18,631
	Operations Support	11,152	1,171	-	12,323
	Other Departments	48,246	5,077	-	53,323
	Regulated Utilities Other	5,020	529	-	5,549
Piedmont	Customer Operations	2,179	226	-	2,405
	Gas Operations	1,751,982	186,420	-	1,938,402
	Other Departments	119,188	12,603	-	131,792
Grand Total - Consolidated		$ 73,825,738	$ 6,427,518	$ 1,908,381	$ 88,161,637

Total Electric

Company	Department	Salary Cost	Short-term Incentive	Long-term Incentive	Total
DE Carolinas	Coal Combustion Products	$ 153,803	$ 16,177	$ -	$ 169,980
	Corporate Groups	1,057	111	-	1,168
	Customer Operations	358,529	37,512	-	396,041
	Fossil Hydro Operations	558,867	59,863	-	618,730
	Gas Operations				-
	Grid Solutions	12,488	1,314	-	13,802
	Market Solutions	575,592	60,482	-	636,074
	Operations Support	402,329	42,052	-	444,381
	Other Departments	554,108	53,702	-	607,810
	Regulated Utilities Other	66,339	6,988	-	73,327
	Renewable Generation	224,847	23,681	-	248,528
	Transmission	27,367	2,876	-	30,243
Service Company	Coal Combustion Products	290,074	33,419	17,762	341,255
	Corporate Groups	3,861,088	441,868	1,247,590	5,550,545
	Customer Connect	369,709	43,516	6,494	418,219
	Customer Operations	1,229,220	123,674	-	1,352,894
	Distribution Operations	992,215	114,245	-	1,106,460
	Fossil Hydro Operations	5,581,273	688,178	17,960	6,687,411
	Gas Operations				-
	Grid Solutions	1,726,827	203,856	-	1,930,683
	Market Solutions	597,816	68,793	-	666,608
	Operations Support	3,192,195	352,709	-	3,544,909
	Other Departments	4,468,882	452,549	97	4,922,308
	Regulated Utilities Other	930,061	106,889	11,755	1,048,705
	Renewable Generation	42,107	4,858	-	46,964
	Transmission	2,395,496	176,577	-	2,572,074
DE Ohio	Customer Operations	1,076,128	81,237	-	1,157,365
	Distribution Operations	74	-	-	74
	Gas Operations				-
	Market Solutions	29,951	3,156	-	33,106
	Operations Support	174,589	11,939	-	186,528
	Other Departments	14,173	1,488	-	15,661
DE Indiana	Coal Combustion Products	493,660	52,010	-	545,669
	Customer Operations	35,725	3,740	-	39,466
	Fossil Hydro Operations	374,907	39,499	-	414,406
	Gas Operations				-
	Market Solutions	72,094	7,579	-	79,672
	Operations Support	46,150	4,846	-	50,996
	Other Departments	69,581	7,331	-	76,912
	Regulated Utilities Other	21,418	2,257	-	23,674
DE Kentucy	Customer Operations	990,262	40,469	-	1,030,731
	Distribution Operations	5,704,979	194,478	-	5,899,456
	Fossil Hydro Operations	8,238,581	237,966	-	8,476,547
	Gas Operations				-
	Grid Solutions	3,612,507	390,018	-	4,002,525
	Market Solutions	185,013	11,037	-	196,050
	Operations Support	525,867	55,266	-	581,134
	Transmission	22,501	946	-	23,447
DE Progress	Coal Combustion Products	432	45	-	477
	Corporate Groups				-
	Customer Operations	58,780	3,649	-	38,429
	Fossil Hydro Operations	119,665	12,574	-	132,238
	Gas Operations				-
	Grid Solutions	5,489	578	-	6,067
	Market Solutions	166,333	17,497	-	183,830
	Operations Support	80,316	8,434	-	88,750
	Other Departments	140,959	14,604	-	155,563
	Regulated Utilities Other	30,426	3,200	-	33,627
	Transmission	2	0	-	2
DE Florida	Coal Combustion Products	2,054	216	-	2,270
	Customer Operations	13,391	1,405	-	14,757
	Distribution Operations	26,456	4,090	-	30,547
	Fossil Hydro Operations	23,709	2,490	-	26,199
	Gas Operations				-
	Market Solutions	16,866	1,765	-	18,631
	Operations Support	11,152	1,171	-	12,323
	Other Departments	48,209	5,073	-	53,282
	Regulated Utilities Other	5,020	529	-	5,549
Piedmont	Customer Operations	2,179	226	-	2,405
	Gas Operations				-
	Other Departments				-
Grand Total - Electric		$ 51,427,628	$ 4,337,688	$ 1,301,658	$ 57,066,984

Total Gas

Company	Department	Salary Cost	Short-term Incentive	Long-term Incentive	Total
DE Carolinas	Coal Combustion Products	$ -	$ -	$ -	$ -
	Corporate Groups	578	61	-	639
	Customer Operations	231,444	24,328	-	255,772
	Fossil Hydro Operations	(5,945)	(624)	-	(6,569)
	Gas Operations	96,438	10,157	-	106,595
	Grid Solutions	3,481	365	-	3,847
	Market Solutions	4,225	473	-	4,799
	Operations Support	552	58	-	610
	Other Departments	28,585	3,062	-	31,647
	Regulated Utilities Other	-	-	-	-
	Renewable Generation	-	-	-	-
	Transmission	-	-	-	-
Service Company	Coal Combustion Products	-	-	-	-
	Corporate Groups	1,327,013	151,691	595,239	2,073,943
	Customer Connect	257,532	29,616	4,527	291,676
	Customer Operations	843,483	85,183	-	928,666
	Distribution Operations	-	-	-	-
	Fossil Hydro Operations	-	-	-	-
	Gas Operations	1,200,193	130,189	6,888	1,337,270
	Grid Solutions	462,322	52,366	-	514,688
	Market Solutions	36,647	4,223	-	40,870
	Operations Support	820	95	-	915
	Other Departments	810,245	81,520	69	891,834
	Regulated Utilities Other	80,234	9,258	-	89,492
	Renewable Generation	-	-	-	-
	Transmission	-	-	-	-
DE Ohio	Customer Operations	61,430	6,441	-	67,871
	Distribution Operations	-	-	-	-
	Gas Operations	128,861	7,632	-	136,493
	Market Solutions	-	-	-	-
	Operations Support	-	-	-	-
	Other Departments	-	-	-	-
DE Indiana	Coal Combustion Products	-	-	-	-
	Customer Operations	201	21	-	222
	Fossil Hydro Operations	-	-	-	-
	Gas Operations	10,267	1,082	-	11,348
	Market Solutions	-	-	-	-
	Operations Support	-	-	-	-
	Other Departments	-	-	-	-
	Regulated Utilities Other	-	-	-	-
DE Kentucy	Customer Operations	-	-	-	-
	Distribution Operations	-	-	-	-
	Fossil Hydro Operations	-	-	-	-
	Gas Operations	12,898,992	1,286,425	-	14,185,417
	Grid Solutions	-	-	-	-
	Market Solutions	-	1	-	1
	Operations Support	-	-	-	-
	Transmission	-	-	-	-
DE Progress	Coal Combustion Products	-	-	-	-
	Corporate Groups	58	6	-	64
	Customer Operations	24,130	2,534	-	26,663
	Fossil Hydro Operations	-	-	-	-
	Gas Operations	16,309	1,717	-	18,027
	Grid Solutions	59	6	-	65
	Market Solutions	-	-	-	-
	Operations Support	507	53	-	560
	Other Departments	269	27	-	296
	Regulated Utilities Other	3,543	372	-	3,915
	Transmission	-	-	-	-
DE Florida	Coal Combustion Products	-	-	-	-
	Customer Operations	2,800	294	-	3,095
	Distribution Operations	-	-	-	-
	Fossil Hydro Operations	-	-	-	-
	Gas Operations	1,528	160	-	1,688
	Market Solutions	-	-	-	-
	Operations Support	-	-	-	-
	Other Departments	37	4	-	41
	Regulated Utilities Other	-	-	-	-
Piedmont	Customer Operations	-	-	-	-
	Gas Operations	1,751,982	186,420	-	1,938,402
	Other Departments	119,188	12,603	-	131,792
Grand Total - Gas		$ 20,398,118	$ 2,089,819	$ 606,723	$ 23,094,657

Duke Energy Kentucky
Analysis of Amounts Allocated and Directly Charged to Duke Energy Kentucky Electric from DEBS
Summarized by Allocation Basis

	12 Months Ended November 30,					
	2012	2013	2014	2015	2016	2017 (1)
Direct Charges	$ 44,670,263	$ 40,280,856	$ 51,407,895	$ 53,711,263	$ 61,356,874	$ 78,327,478
Allocated Charges:						
Accounting	2,218,977	2,510,609	1,351,267	629,816	647,960	513,116
Circuit Miles	387,107	355,390	187,337	183,460	243,925	233,691
Circuit Miles and Electric Peak Load	117,020	63,080	12,975	13,420	9,947	3,404
Construction	1,750,497	1,029,703	1,244,971	935,488	1,178,797	1,862,847
CPU Seconds (MIPS)	387,466	252,858	204,236	175,205	178,219	162,791
Customers	5,304,624	4,118,006	3,436,042	3,271,742	2,885,663	2,368,023
Customers and Employees	122,045	62,794	56,243	58,537	59,358	48,826
Electric Peak Load	13,981	5,152	5,610	2,654	4,629	4,043
Employees	1,668,191	1,224,875	894,971	803,088	831,951	552,592
Generation Capacity	1,258,566	1,035,786	1,277,556	1,073,482	1,093,384	1,069,467
Interest	94,209	54,219	38,230	63,151	68,653	83,990
Procurement	518,038	474,457	373,183	502,791	767,104	548,660
Sales	854,597	602,968	326,483	161,007	56,234	73,726
Servers	1,282,084	1,280,778	821,545	671,445	590,831	416,193
Square Footage	448,174	461,213	365,411	206,207	94,482	92,416
Three Factor Formula	10,062,973	8,983,057	7,315,559	6,718,326	6,041,243	4,848,210
Workstations	118,757	120,873	58,406	36,860	39,425	418,865
Total Allocated Charges	26,607,307	22,635,819	17,970,023	15,506,679	14,791,806	13,300,860
Total Direct and Allocated Charges	$ 71,277,570	$ 62,916,675	$ 69,377,918	$ 69,217,942	$ 76,148,680	$ 91,628,337

(1) Includes October '17 and November '17 annualized amounts

DUKE ENERGY KENTUCKY
KWH SALES BY CLASS

		Classification						
	Month	00-Residential	02-Commercial	04-Industrial	15-Street Light	18-OPA	51-Interdepartmental	Grand Total
Group1	11/1/2012	96,474,759	109,490,239	64,351,371	1,268,967	22,965,210	65,526	294,616,072
	12/1/2012	121,608,388	118,303,128	65,308,332	1,164,007	23,426,345	66,874	329,877,074
	1/1/2013	152,280,170	123,789,842	64,826,370	1,466,003	24,736,847	131,007	367,230,239
	2/1/2013	137,139,267	114,858,602	62,619,026	1,310,335	22,868,844	80,870	338,876,744
	3/1/2013	128,401,283	112,148,240	62,565,048	1,239,908	23,192,703	62,682	327,609,864
	4/1/2013	110,039,126	113,585,501	64,181,471	1,266,015	22,943,672	55,305	312,051,090
	5/1/2013	86,539,070	112,697,465	64,934,459	1,253,850	22,618,895	55,425	288,099,164
	6/1/2013	112,997,177	126,259,233	68,062,217	1,244,124	23,391,091	62,761	332,016,603
	7/1/2013	143,086,411	136,650,173	70,878,709	1,233,775	24,843,163	66,892	376,759,123
	8/1/2013	130,602,222	129,993,644	72,033,678	1,239,701	24,421,291	105,066	358,395,602
	9/1/2013	138,009,454	135,768,208	72,350,888	1,263,640	27,139,866	62,710	374,594,766
	10/1/2013	93,760,059	118,084,458	68,980,810	1,257,099	25,275,507	52,810	305,410,743
Group1 Total		**1,450,937,386**	**1,449,608,733**	**801,092,379**	**15,207,424**	**287,823,434**	**867,728**	**4,005,537,084**
Group2	11/1/2013	96,291,313	111,128,804	69,391,006	1,275,996	22,845,959	62,418	300,995,496
	12/1/2013	136,215,218	121,682,569	68,007,009	1,311,729	25,146,671	75,069	352,438,265
	1/1/2014	166,084,837	128,097,153	68,389,592	1,314,277	24,978,394	259,191	389,123,444
	2/1/2014	163,277,363	121,293,580	64,659,447	1,327,121	24,688,016	168,954	375,424,481
	3/1/2014	136,018,156	114,177,573	64,931,522	1,242,645	24,166,659	82,245	340,618,801
	4/1/2014	99,896,142	111,005,169	66,107,006	1,283,851	22,186,900	475,654	300,954,722
	5/1/2014	86,626,477	113,348,617	66,752,306	1,167,675	22,653,154	-378,028	290,170,201
	6/1/2014	116,591,974	127,465,377	70,809,093	1,340,016	24,843,303	43,958	341,093,721
	7/1/2014	138,285,345	135,110,456	74,357,472	1,241,483	24,723,158	52,077	373,770,001
	8/1/2014	122,788,982	127,711,044	70,367,368	1,037,289	23,884,575	42,271	345,831,529
	9/1/2014	132,462,010	134,174,735	72,990,049	1,460,871	27,307,930	42,018	368,437,613
	10/1/2014	87,414,836	112,279,063	69,815,440	1,265,492	23,700,616	74,508	294,549,955
Group2 Total		**1,481,952,653**	**1,457,474,150**	**826,587,310**	**15,268,446**	**291,125,335**	**1,000,335**	**4,073,408,229**
Group3	11/1/2014	91,941,404	109,573,824	67,967,214	1,275,373	21,821,524	40,126	292,619,465
	12/1/2014	138,358,693	125,707,381	70,251,982	1,318,141	24,878,519	51,161	360,563,877
	1/1/2015	157,081,314	126,619,946	67,731,982	1,289,473	24,224,806	132,576	377,080,097
	2/1/2015	149,212,765	121,518,298	65,507,385	1,289,872	24,012,339	72,156	361,612,815
	3/1/2015	142,961,187	116,746,411	64,910,125	1,264,201	24,253,094	162,467	350,297,485
	4/1/2015	94,910,006	113,444,050	65,854,391	1,202,920	21,765,147	89,079	297,285,593
	5/1/2015	89,588,868	114,940,954	64,146,908	1,292,325	22,781,411	35,127	292,785,593
	6/1/2015	119,388,398	130,035,376	69,723,447	1,244,921	25,193,835	42,162	345,628,139
	7/1/2015	135,181,174	137,254,974	71,240,319	1,240,617	24,593,340	48,258	369,558,682
	8/1/2015	140,292,617	134,386,000	71,261,628	1,240,789	25,341,249	45,397	372,569,680
	9/1/2015	128,810,815	134,587,468	73,281,538	1,251,465	27,586,829	48,113	365,566,226
	10/1/2015	91,524,078	118,558,934	68,224,550	1,260,310	24,785,811	32,881	304,366,564
Group3 Total		**1,479,251,319**	**1,483,375,616**	**820,101,467**	**15,170,407**	**291,235,904**	**799,503**	**4,089,934,216**
Group4	11/1/2015	83,481,489	109,773,806	64,491,398	1,276,777	22,567,889	47,236	281,638,595
	12/1/2015	113,454,422	120,031,869	66,148,433	1,266,496	23,882,570	48,607	324,832,397
	1/1/2016	143,097,046	124,196,576	65,946,466	1,360,131	24,262,899	187,678	359,050,796
	2/1/2016	135,063,836	117,495,904	64,447,649	911,892	23,563,600	117,804	341,600,685
	3/1/2016	109,361,914	113,909,193	65,576,157	1,225,924	22,900,062	38,633	313,011,883
	4/1/2016	91,346,387	111,060,681	64,380,876	1,630,373	22,160,329	29,738	290,608,384
	5/1/2016	82,203,029	110,983,506	63,907,079	1,204,919	22,465,627	27,038	280,791,198
	6/1/2016	118,445,480	130,280,864	70,847,496	1,216,590	23,470,557	27,038	344,290,025
	7/1/2016	146,882,042	139,768,795	70,323,291	1,337,745	24,611,228	27,038	382,750,139
	8/1/2016	161,396,975	145,380,541	71,784,906	1,239,708	27,342,778	130,239	407,255,147
	9/1/2016	149,142,564	143,745,181	74,657,481	1,286,506	28,833,573	50,049	397,715,354
	10/1/2016	103,227,755	122,887,853	66,773,146	1,050,304	25,520,812	49,225	319,509,095
Group4 Total		**1,436,902,939**	**1,489,494,769**	**809,284,378**	**15,009,365**	**291,581,924**	**780,323**	**4,043,053,698**
Group5	11/1/2016	85,420,842	110,526,089	63,781,538	1,483,472	23,030,883	38,447	284,281,271
	12/1/2016	126,293,795	123,799,146	66,551,298	1,314,287	24,304,353	34,154	344,297,033
	1/1/2017	152,260,687	125,774,982	63,354,620	1,285,611	24,592,459	129,877	367,398,236
	2/1/2017	116,857,527	113,534,919	63,352,735	1,283,934	21,395,892	168,021	316,593,028
	3/1/2017	105,428,213	111,492,272	61,886,999	1,237,187	22,219,128	473,912	302,737,711
	4/1/2017	92,266,565	112,433,824	63,784,958	1,260,933	21,364,175	-372,632	290,717,823
	5/1/2017	88,890,938	114,871,932	66,379,122	1,241,605	22,843,977	30,158	294,257,732
	6/1/2017	116,046,794	126,678,029	69,194,357	1,161,767	20,680,591	27,526	335,789,064
	7/1/2017	143,429,891	137,101,417	69,359,024	1,314,299	25,721,462	48,032	376,974,125
	8/1/2017	139,943,905	133,873,389	71,751,787	1,231,443	24,905,063	43,833	371,749,420
	9/1/2017	116,055,029	128,960,748	70,464,367	1,249,583	24,877,038	46,825	341,453,590
Group5 Total		**1,282,894,186**	**1,341,046,747**	**731,840,805**	**14,064,121**	**255,735,021**	**668,153**	**3,626,249,033**

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-005

REQUEST:

Refer to the Application, Volume 11, Tab 51; Duke Kentucky's responses to Staff's First Request for Information to Duke Kentucky ("Staff's First Request"). Item 66; and the Direct Testimony of Thomas Silinski ("Silinski Testimony") beginning at page 34 regarding employee benefit plans.

a. Provide the jurisdictional employee medical insurance adjustment assuming the following: Total Healthcare/Medical Cost for Each Level of Coverage = Company Paid Portion of Premium + Employee Contribution to Premium. Continue to assume that the employee would pay 21 percent of the total cost for single coverage and 33 percent of the total cost for all other types of coverage, compared to the amount of healthcare/medical insurance expense incurred the test year.

b. Provide the jurisdictional dental insurance adjustment in the test year assuming employees would pay 60 percent of the total cost of coverage. Calculate the amount as follows: Total Dental Cost for Each Level of Coverage = Company Paid Portion of Premium + Employee Contribution to Premium.

c. Provide a schedule that identifies the jurisdictional cost for providing long-term disability insurance.

d. Provide a schedule that identifies the costs for providing group life insurance coverage for coverage over $50,000.

e. For employees who participate in a defined benefit plan, provide the total and jurisdictional amount of matching contributions made on behalf of employees who also participate in any 401(k) retirement savings account.

f. Provide the information requested in items a. through e. that are passed through from Duke Energy or other affiliated companies.

RESPONSE:

Please see STAFF-DR-02-005 Attachment

PERSON RESPONSIBLE: Tom Silinski

Question No. 5 - Second Request
Responding Witness: Tom Silinski

The below is an analysis of the Test Period numbers:

		Kentucky		Allocated from Affiliates	
A.	Total Costs:				
	Single Coverage	356,507		230,865	
	Other Coverage	1,728,327		1,119,222	
	Total	2,084,834		1,350,087	
	Employee Cost:				
	Single Coverage	71,301	20%	46,173	20%
	Other Coverage	570,348	33%	369,343	33%
	Total	641,649		415,516	
	Employer Cost:				
	Single Coverage	285,206		184,692	
	Other Coverage	1,157,979		749,879	
	Total	1,443,185		934,571	
	Total KY Cost (Previously submitted)	1,737,361		1,125,073	
	Change	294,176		190,502	

Note: The calculations above only look at the premium cost share. It does not reflect the out of pocket costs incurred by the employee (coinsurance, copays, deductibles). For medical coverage, the employee pays on average 17% of the premium and 34% of the total cost of coverage.

		Kentucky		Allocated from Affiliates	
B.	Total Costs:				
	Single Coverage	20,376		13,694	
	Other Coverage	136,786		91,931	
	Total	157,162		105,625	
	Employee Cost:				
	Single Coverage	12,225	60%	8,216	60%
	Other Coverage	82,072	60%	55,158	60%
	Total	94,297		63,375	
	Employer Cost:				
	Single Coverage	8,150		5,478	
	Other Coverage	54,714		36,772	
	Total	62,865		42,250	
	Total KY Cost (Previously submitted)	102,627		68,973	
	Change	39,762		26,723	

Note: The calculations above only look at the premium cost share. It does not reflect the out of pocket costs incurred by the employee (coinsurance, copays, deductibles). For dental coverage, the employee pays on average 35% of the premium and 56% of the total cost of coverage.

C. For the Test period, the jurisdictional cost for providing salary continuation insurance is expected to be the following

Kentucky	45,501
Allocated from Affiliates	30,460
Total	75,961

D. For the Test period, the jurisdictional cost for providing life insurance coverage over $50k is expected to be the following:

Kentucky	6,594
Allocated from Affiliates	4,414
Total	11,008

E. For the Test period, the jurisdictional cost of company match for individuals with a DC and DB plan is expected to be the following:

Kentucky	991,325
Allocated from Affiliates	588,436
Total	1,579,761

F. See 'allocated from affiliates' portion of A-E above

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-006

REQUEST:

Refer to the Application, Volume 12, Schedule K, page 4 of 5.

a. Provide Duke Kentucky's monthly return on equity ("ROE") from 2016 through to-date 2017.

b. Explain why Duke Kentucky forecasts its ROE to decline 23.7 percent from 10.13 percent in 2016 to 8.21 percent in the base period ending November 30, 2017.

c. Explain why Duke Kentucky forecasts its ROE to decline 43.0 percent from 8.21 percent in the base period to 5.74 percent in the forecasted test period ending March 31, 2018.

RESPONSE:

a. See attachment Staff-DR-02-006 a – Attachment 1

b. ROE is forecasted to decline from 10.13 percent in 2016 to 8.21 percent in the base period primarily due to a decrease in net income. The decrease in net income is due to favorable income tax adjustments in 2016 that were not expected to repeat in the base period.

c. ROE is forecasted to decline from 8.21 percent in the base period to 3.93 percent in the forecasted period primarily due to a decrease in net income. The decrease in net income is driven by increased depreciation, increased interest expense, and increased costs for planned plant outages. The increased depreciation and interest

expense are primarily due to additional investment in utility plant and the related increase in outstanding debt.

PERSON RESPONSIBLE: David Doss (a)
Robert H. Pratt (b & c)

Duke Energy Kentucky
Schedule of ROE's
For FY 2016 and 2017 to Date

	ROE
January 2016	11.00%
February	10.75%
March	11.01%
April	10.16%
May	9.83%
June	9.89%
July	10.69%
August	10.30%
September	10.42%
October	10.94%
November	11.22%
December 2016	10.12%
January 2017	9.16%
February	9.07%
March	8.31%
April	9.09%
May	8.78%
June	8.75%
July	8.25%
August	8.44%
September 2017	7.71%

ROE is based on trailing twelve month's (TTM) income and a 13 month equity average

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-007

REQUEST:

Refer to Duke Kentucky's current tariff on file with the Commission and to the Application, Volume 13, Schedule L-1. Confirm that the Appliance Recycling Program should no longer be included in Duke Kentucky's tariff.

RESPONSE:

Correct. The Appliance Recycling Program is no longer active.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-008

REQUEST:

Refer to the Application, Volume 13, Schedule L01, pages 2-4 of 148.

a. Explain why the following schedules included in the index are not included in the proposed tariff: Rider DSM, Demand Side Management Cost Recovery Program; Rider PLM, Peak Load Management Program; Rider DSMR, Demand Side Management Rate; Residential Comprehensive Energy Education Program (NEED); Residential Smart Saver; Residential Conservation and Energy Education; Residential Direct Load Control – Power Manager Program; Residential Home Energy House Cell; Energy Star Products; CI High Efficiency Incentive; Energy Efficiency Website; Personalized Energy Report; Smart Saver Custom Program; and Payment Plus.

b. Explain why numerous effective dates listed on the check sheet do not correspond to the effective dates listed on the proposed individual schedules.

RESPONSE:

a. All of the schedules listed above are part of the Company's DSM portfolio of programs. There are no changes to any of the listed schedules being proposed in this proceeding, and as such, the schedules were not filed in this proceeding. Historically changes to any of the Company's DSM tariff sheets are typically addressed separately in the context of the Company's annual DSM filings such as

Company's pending case 2017-00324, Application for Duke Energy Kentucky to Amend its Demand Side Management Programs. If desired, the Company will file all DSM program related tariff sheets upon request and update the index appropriately.

b. There was an inadvertent error and misunderstanding related to the need to update tariff sheets that did not require any text revision other than to update to the current Duke Energy Kentucky president's name or the effective date. The index sheet dates were not updated for those sheets that were only revised with the current president's name or an update to the effective date. The index sheet will be revised to the appropriate dates upon conclusion of this proceeding.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-009

REQUEST:

Refer to the Application, Volume 13, Schedule L-1, page 15 of 148 regarding paragraph "7. Availability of Budget Billing and Fixed Bill."

a. Provide the provisions of the Budget Billing Plan.

b. 807 KAR 5:006, Section 14(2)(a)(3), requires that the provisions of a budget payment plan be included in the utility's tariff. Explain whether Duke Kentucky believes paragraph "7. Availability of Budget Billing and Fixed Bill" complies with this regulation.

c. Indicate whether Duke Kentucky would be willing to include the provisions of its budget payment plan in its tariff.

d. Also, refer to the Direct Testimony of Alexander "Sasha" J. Weintraub, Ph.D. ("Weintraub Testimony"), page 12, lines 5-10. The Weintraub Testimony indicates that the Fixed Bill program is described in Duke Kentucky's billing tariff. The provisions of the Fixed Bill program do not appear to be included in the proposed tariff, other than a brief mention of the program's name. Indicate whether Duke Kentucky would be willing to include the provisions of the Fixed Bill program in its tariff.

RESPONSE:

a. As stated in Company's tariff referenced above, the Budget Payment Plan is a bill payment option that reduces monthly bill amount fluctuations. See STAFF-DR-02-009 Attachment A for additional information on the Budget Payment Plan.

b. Yes.

c. Company is amenable to provide more detail such as information in STAFF-DR-02-009 Attachment A.

d. Yes.

PERSON RESPONSIBLE: Bruce Sailers (a - c)
Sasha Weintraub (d)

Duke Energy Kentucky Budget Payment Plans

Annual Plan

- The Annual Plan provides 11 months of equal payments with a settle-up on the 12th month.
- The usage amount for bill calculation is calculated using 12 months usage, then divides by 11.
- A bill message is sent after 6 months with a suggested new amount if variance to the actual bill amount is +/– 30% or greater; but the amount does not change automatically.
- Customer must call to change amount.
- The amount is changed after the 12 month review as needed.

Quarterly Plan

- The Quarterly Plan provides quarterly review and adjustment of the budget payment amount to prevent a settle-up month.
- The usage amount for bill calculation uses 12 months usage and divides by 12.
- Reviews occur after 3, 6, 9, and 12 months on the plan and continue every 3 months thereafter.
- A bill message is sent after reviews with a new bill amount if variance to the actual bill amount is +/– 10% or greater.
- The bill amount automatically changes. The customer does not need to call.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-010

REQUEST:

Refer to the Application, Volume 13, Schedule L-1, page 82 of 148. State the number of customers, if any, who have notified Duke Kentucky that they wish to opt-out of receiving an advanced meter.

RESPONSE:

As of October 29, 2017, 35 customers have notified Duke Energy Kentucky that they wish to opt-out of receiving an advanced meter.

PERSON RESPONSIBLE: Donald L Schneider

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-011

REQUEST:

Refer to the Application, Volume 13, Schedule L-1, page 84 of 148, which defines "Monthly Kentucky Retail Revenue R(m)" as "the average monthly revenue, excluding all rider revenues, for the last 12 month period." Refer also to the Application, Volume 15, Attachment SEL-2, page 10 of 10, which shows Duke Kentucky's proposed calculation of R(m).

a. Confirm that the proposed tariff language does not provide for the separation of residential and non-residential customers.

b. Confirm that the proposed tariff language does not provide for the exclusion of fuel revenues from the non-residential R(m).

c. Explain whether the proposed tariff language "all rider revenues" is intended to mean "all Rider ESM revenues."

d. Confirm that only environmental surcharge revenues are excluded from the residential R(m) and that environmental surcharge revenues and fuel revenues are excluded from the non-residential R(m).

RESPONSE:

a. The proposed tariff language that was filed does not provide for the separation of residential and non-residential customers but it was the intent of the Company that residential and non-residential customers would have different environmental

surcharge factors as outlined in Attachment SEL-2. The Company is amenable to amending the tariff language if so desired.

b. The proposed tariff language does not provide for the exclusion of fuel revenues from the non-residential R(m) but it was the intent of the Company to use the 12 month average non-fuel revenue in the calculation of the environmental surcharge factor for non-residential customers as outlined on Attachment SEL-2. The Company modeled Attachment SEL-2 page 10 of 10 after the same sheet used by LG&E in a proceeding previously approved by the KPSC.

c. The proposed tariff language "all rider revenues" is intended to mean "all Rider ESM revenues." The Company is amenable to amending the tariff language if so desired.

d. Only environmental surcharge revenues are excluded from the residential R(m) and both environmental surcharge revenues and fuel revenues are excluded from the non-residential R(m).

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-012

REQUEST:

Refer to the Application, Volume 13, Schedule L-1, page 89 of 148.

a. For factor NF, explain the types of charges and credits Duke Kentucky expects to include in this factor.

b. For factor CAP, explain whether Duke Kentucky intends to include capacity performance penalties from PJM Interconnection, LLC ("PJM") when Duke Kentucky's units are assessed for non-performance during a capacity emergency event as declared by PJM.

c. If the answer to part b. above is that Duke Kentucky does intend to include capacity performance penalties, explain whether it is reasonable that Duke Kentucky's customers bear 90 percent of the risk of the penalties and that shareholders bear only 10 percent of the risk.

d. For factors NF and CAP, explain whether Duke Kentucky anticipates these factors would primarily be credits to customers or charges from customers.

RESPONSE:

a. Referring to the Attachment JDS-4 to John D. Swez's testimony, NF would include any charges in the billing line item range of 1200 through 1500 that is only in the PSM column (not in both the FAC and PSM columns) and any credits

in the billing line item range of 2210 through 2510 that is only in the PSM column (not in both the FAC and PSM columns).

b. Assessments from PJM for non-performance are included in the proposed Rider PSM formula.

c. As described in the proposed tariff and the testimony of William Don Wathen Jr., the Company proposes to include both capacity assessments and capacity credits. The sharing mechanism is balanced in that customers will receive 90 percent of any benefit as well as 90 percent of the cost. The PJM capacity performance structure is a FERC-approved tariff. The Company is offering to share in 10 percent of the costs and allow customers to receive 90 percent of the benefit.

d. For the NF variable, it is not possible to forecast what the net charges/credits may be. For the CAP component, the Company's efforts to improve the reliability and performance of East Bend Unit 2, along with the completion of the proposed backup fuel supply project at Woodsdale are intended to minimize the potential for capacity performance assessments. As long as Duke Energy Kentucky remains in PJM and as long as it owns and operates East Bend and Woodsdale in PJM, it has the potential, however small, of unscheduled outages during an event that would result in capacity performance assessments.

PERSON RESPONSIBLE: William D. Wathen Jr.

STAFF-DR-02-013

REQUEST:

Refer to the Direct Testimony of James P. Henning ("Henning Testimony"), pages 8-8.

a. Explain how Duke Kentucky funds its economic development activities.

b. Regarding the "Site Readiness" program that is administered by Duke Energy:

   1) Explain in detail Duke Kentucky's role in this program, how a local community would be eligible to receive funding through this program, and the source of the funds provided by Duke Energy to an eligible local community.

   2) Within the last ten years, has any local community located in Duke Kentucky's service area been a recipient of funds through the Site Readiness program? If so, provide details on when the funding occurred, the identity of the local community, the amount of funding, and the type of economic development involved.

c. Throughout this proceeding, provide updates on any new or expanded economic development projects that Duke Kentucky is promoting in conjunction with its economic development organization listed on page 9.

RESPONSE:

a. Economic Development activities are funded through the Company's Operation and Maintenance Budgets.

b. 1) The Site Readiness Program provides funding and expertise to help communities identify, assess, improve and increase awareness of industrial sites and buildings in the Duke Energy Kentucky service territory. The program works in tandem with local economic development organizations (LEDOS) and Regional Economic Development organizations (REDOS) to:

- Identify potential new sites for development / redevelopment;
- Assess strengths and weaknesses of the development;
- Recommend how to mitigate weaknesses;
- Assist with marketing "build ready" sites; and
- Qualify, develop and sell sites to create jobs and economic opportunity in our service territory.

2) Yes. The Matching Fund Grant was for the undeveloped industrial property at 1302-1310 Gloria Terrell Drive, Wilder, Kentucky. The amount of the of the funding was $10,000 in 2015. Tri-Ed applied for the grant and the funds were matched by Northern Kentucky Area Development District.

c. The Company agrees to provide updates.

PERSON RESPONSIBLE: Chuck Session

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-014

REQUEST:

Refer to the Henning Testimony, page 16. Provide the annual inflation rates for the years 2006-2016 and the monthly inflation rates for 2017 to date.

RESPONSE:

Period	Avg CPI[a]	Avg Annual Increase %
2006	201.59	
2007	207.34	2.85%
2008	215.30	3.84%
2009	214.54	-0.36%
2010	218.06	1.64%
2011	224.94	3.16%
2012	229.59	2.07%
2013	232.96	1.46%
2014	236.74	1.62%
2015	237.02	0.12%
2016	240.01	1.26%

Month	CPI [a]	Increase over Prior Month
Dec 2016	241.43	
Jan 2017	242.84	0.58%
Feb 2017	243.60	0.31%
Mar 2017	243.80	0.08%
Apr 2017	244.52	0.30%
May 2017	244.73	0.09%
Jun 2017	244.96	0.09%
Jul 2017	244.79	-0.07%
Aug 2017	245.52	0.30%
Sep 2017	246.82	0.53%
Oct 2017	-	n/a
Nov 2017	-	n/a
Dec 2017	-	n/a

(a) From the Bureau of Labor Statistics website, www.bls.gov.

See attached worksheet STAFF-DR-02-014 Attachment.xls

PERSON RESPONSIBLE: William Don Wathen Jr.

CPI-All Urban Consumers (Current Series)
Original Data Value

Series Id: CUUR0000SA0
Not Seasonally Adjusted
Series Title: All items in U.S. city average, all urban
Area: U.S. city average
Item: All items
Base Period: 1982-84=100
Years: 2006 to 2017

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2006	198.30	198.70	199.80	201.50	202.50	202.90	203.50	203.90	202.90	201.80	201.50	201.80
2007	202.42	203.50	205.35	206.69	207.95	208.35	208.30	207.92	208.49	208.94	210.18	210.04
2008	211.08	211.69	213.53	214.82	216.63	218.82	219.96	219.09	218.78	216.57	212.43	210.23
2009	211.14	212.19	212.71	213.24	213.86	215.69	215.35	215.83	215.97	216.18	216.33	215.95
2010	216.69	216.74	217.63	218.01	218.18	217.97	218.01	218.31	218.44	218.71	218.80	219.18
2011	220.22	221.31	223.47	224.91	225.96	225.72	225.92	226.55	226.89	226.42	226.23	225.67
2012	226.67	227.66	229.39	230.09	229.82	229.48	229.10	230.38	231.41	231.32	230.22	229.60
2013	230.28	232.17	232.77	232.53	232.95	233.50	233.60	233.88	234.15	233.55	233.07	233.05
2014	233.92	234.78	236.29	237.07	237.90	238.34	238.25	237.85	238.03	237.43	236.15	234.81
2015	233.71	234.72	236.12	236.60	237.81	238.64	238.65	238.32	237.95	237.84	237.34	236.53
2016	236.92	237.11	238.13	239.26	240.23	241.02	240.63	240.85	241.43	241.73	241.35	241.43
2017	242.84	243.60	243.80	244.52	244.73	244.96	244.79	245.52	246.82			

Source: Bureau of Labor Statistics

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-015

REQUEST:

Refer to the Henning Testimony, page 24. Duke Kentucky is proposing one program, Targeted Underground, to be recovered through the proposed Distribution Capital Investment Rider ("Rider DCI"). Provide other programs that Duke Kentucky is considering to be included for recovery via Rider DCI in the future and their estimated costs.

RESPONSE:

Duke Energy Kentucky has not considered inclusion of any other programs in Rider DCI at this early stage.

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

PUBLIC STAFF-DR-02-016

REQUEST:

Refer to the Henning Testimony, page 26. Provide costs that Duke Kentucky has incurred to date for short-term capacity purchases necessary to meet its Fixed Resource Requirement ("FRR") plan obligations.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET

The confidential tables above describe short term capacity purchases made since Duke Energy Kentucky joined PJM in January of 2012, and the capacity sales obligations assumed with Duke Energy Kentucky's purchase of Dayton Power and Light's share of East Bend 2. The purchases fall into two broad categories, purchases to cover shortfalls in projected available capacity to meet either initial or final FRR plans or to provide capacity to meet expected assessments from PJM for capacity availability during PJM Summer and Winter Performance Periods (Rows A, B, and I), and capacity purchases

made for replacement purposes related to Duke Energy Kentucky's purchase of Dayton Power and Light's share of East Bend 2 (Rows C, D, E, F, G, and H).

The costs associated with the East Bend 2 replacement capacity purchases offset the sales described in rows J,K,L, and M. Costs associated with purchases in rows A, B, and were not recovered by the Company. Costs and the associated net revenues from purchases in rows C, D, E, F, G, and H and revenues from sales in rows J,K,L and M were passed as a credit through the Rider PSM consistent with the Commission's Order in Case No. 2014-00201.

PERSON RESPONSIBLE: John Verderame

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-017

REQUEST:

Refer to the Henning Testimony, page 29. Provide a detailed list that comprises the $600 million in utility plant investment since the 2006 rate case.

RESPONSE:

See Staff-DR-02-017 Attachment for the breakout by utility account of the $600 million in utility plant investment since the 2006 rate case.

PERSON RESPONSIBLE: Cynthia S. Lee

DUKE ENERGY KENTUCKY, INC.
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS

STEAM PRODUCTION PLANT
($000 Omitted)

Note 1: Obtained from Schedule B-2.1, pages 7-12 of current case
Note 2: Obtained from Schedule B-2.1, pages 7-12 from prior rate case

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Note 1 13 Month Average Adjusted as of Mar 31, 2019 (a) $	Note 2 13 Month Average Adjusted as of Dec 31, 2007 (b) $	Utility Plant Investment since 2006 rate case (a) - (b) $
1	310	3100	Land and Land Rights	7,047	1,687	5,360
2	311	3110	Structures & Improvements	52,962	38,304	14,658
3	311	3110 - ENV	Structures & Improvements	18,410	0	18,410
4	312	3120	Boiler Plant Equipment	200,625	313,995	(113,370)
5	312	3120 - ENV	Boiler Plant Equipment	242,408	0	242,408
6	312	3122	Boiler Plant Equip - Precipitator	0	11,773	(11,773)
7	312	3123	Boiler Plant Equip - SCR Catalyst	11,284	2,230	9,054
8	312	3123 - ENV	Boiler Plant Equip - SCR Catalyst	5,421	0	5,421
9	314	3140	Turbogenerator Equipment	89,139	78,497	10,642
10	314	3140 - ENV	Turbogenerator Equipment	10,590	0	10,590
11	315	3150	Accessory Electric Equipment	29,008	29,433	(425)
12	315	3150 - ENV	Accessory Electric Equipment	16,979	0	16,979
13	316	3160	Miscellaneous Powerplant Equipment	14,454	9,031	5,423
14	317	3160 - ENV	Miscellaneous Powerplant Equipment	5,796	0	5,796
15	317	3171, 3172	ARO - Steam Production	0	710	(710)
16			Completed Construction Not Classified	82,240	15,516	66,724
17		ENV	Completed Construction Not Classified	13,269	0	13,269
18			Total Production Plant	799,631	501,176	298,455

DUKE ENERGY KENTUCKY, INC.
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS

OTHER PRODUCTION PLANT
($000 Omitted)

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Note 1 13 Month Average Adjusted as of Mar 31, 2019 (a)	Note 2 13 Month Average Adjusted as of Dec 31, 2007 (b)	Utility Plant Investment since 2006 rate case (a) - (b)
				$	$	$
1	340	3400	Land and Land Rights	2,259	2,258	1
2	340	3401	Rights of Way	652	652	(0)
3	341	3410	Structures & Improvements	32,108	33,726	(1,618)
4	341	3410 - Pollution	Structures & Improvements	3,959	0	3,959
5	342	3420	Fuel Holders, Producers, Accessories	15,706	15,508	198
6	343	3430	Prime Movers	0	1,362	(1,362)
7	344	3440	Generators	206,270	188,960	17,310
8	344	3440 - Pollution	Generators	10,451	0	10,451
9	344	3440 - Solar	Generators	14,574	0	14,574
10	345	3450	Accessory Electric Equipment	21,204	16,867	4,337
11	345	3450 - Pollution	Accessory Electric Equipment	456	0	456
12	346	3460	Miscellaneous Plant Equipment	4,041	3,677	364
13	346	3460 - Pollution	Miscellaneous Plant Equipment	601	0	601
14			Completed Construction Not Classified	21,867	14,824	7,043
15			Total Other Production Plant	334,147	277,834	56,313

DUKE ENERGY KENTUCKY, INC.
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS

TRANSMISSION PLANT
($000 Omitted)

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Note 1 13 Month Average Adjusted as of Mar 31, 2019 (a)	Note 2 13 Month Average Adjusted as of Dec 31, 2007 (b)	Utility Plant Investment since 2006 rate case (a) - (b)
				$	$	$
1	350	3500	Land	247	191	56
2	350	3501	Rights of Way	1,092	906	186
3	352	3520	Structures & Improvements	1,455	381	1,074
4	353	3530	Station Equipment	17,085	10,343	6,742
5	353	3531	Station Equipment - Step Up	9,374	0	9,374
6	353	3532	Station Equipment - Major	5,891	0	5,891
7	353	3534	Station Equipment - Step Up Equipment	7,057	0	7,057
8	355	3550	Poles & Fixtures	7,524	5,133	2,391
9	356	3560	Overhead Conductors & Devices	5,837	4,370	1,467
10	356	3561	Overhead Conductors - Clear R/W	297	0	297
11			Completed Construction Not Classified	9,891	2,442	7,449
12			Total Transmission Plant	65,749	23,766	41,983

DUKE ENERGY KENTUCKY, INC.
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS

DISTRIBUTION PLANT
($000 Omitted)

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Note 1 13 Month Average Adjusted as of Mar 31, 2019 (a) $	Note 2 13 Month Average Adjusted as of Dec 31, 2007 (b) $	Utility Plant Investment since 2006 rate case (a) - (b) $
1	360	3600	Land and Land Rights	6,822	3,094	3,728
2	360	3601	Rights of Way	6,441	4,460	1,981
3	361	3610	Structures & Improvements	1,382	309	1,073
4	362	3620	Station Equipment	37,037	34,202	2,835
5	362	3622	Station Equipment - Major	25,188	0	25,188
6	364	3640	Poles,Towers & Fixtures	56,761	44,360	12,401
7	365	3650	Overhead Conductors & Devices	113,759	61,283	52,476
8	365	3651	Overhead Conductors - Clear R/W	1,864	0	1,864
9	366	3660	Underground Conduit	19,177	14,371	4,806
10	367	3670	Underground Conductors & Devices	59,569	33,388	26,181
11	368	3680	Line Transformers	55,367	47,561	7,806
12	368	3682	Customers Transformer Installation	274	1,716	(1,442)
13	369	3691	Services - Underground	2,394	515	1,879
14	369	3692	Services - Overhead	15,792	10,256	5,536
15	370	3700	Meters	1,106	13,852	(12,746)
16	370	3700	Instrumentation Transformers	713	0	713
17	370	3701	Leased Meters	0	0	0
18	370	3702	AMI Meters	22,411	0	22,411
19	371	3711, 3712	Area Lighting, Co Owned Outdoor Light	421	0	421
20	372	3720	Leased Property on Customers	10	10	(0)
21	373	3731	Street Lighting - Overhead	2,641	2,861	(220)
22	373	3732	Street Lighting - Boulevard	3,359	2,819	540
23	373	3733	Street Lighting - Cust,Private Outdoor Lighting	0	1,617	(1,617)
24	373	3734	Light Choice OLE	0	0	0
25			Completed Construction Not Classified	38,934	18,840	20,094
26			Total Distribution Plant	471,421	295,514	175,907

DUKE ENERGY KENTUCKY, INC.
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS

GENERAL PLANT
($000 Omitted)

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Note 1 13 Month Average Adjusted as of Mar 31, 2019 (a)	Note 2 13 Month Average Adjusted as of Dec 31, 2007 (b)	Utility Plant Investment since 2006 rate case (a) - (b)
				$	$	$
1	303	3030	Miscellaneous Intangible Plant	12,504	2,130	10,374
2	390	3900	Structures & Improvements	145	16	129
3	391	3910	Office Furniture & Equipment	15	36	(21)
4	391	3911	Electronic Data Proc Equip	2,474	0	2,474
5	392	3920	Transportation Equipment	219	0	219
6	392	3921	Trailers	201	100	101
7	394	3940	Tools,Shop & Garage Equipment	2,071	468	1,603
8	396	3960	Power Operated Equipment	12	12	(0)
9	397	3970	Communication Equipment	2,886	84	2,802
10			Completed Construction Not Classified	8,027	589	7,438
11			Total General Plant	28,554	3,435	25,119
12			Total Electric Plant	1,699,503	1,101,725	597,778

DUKE ENERGY KENTUCKY, INC.
PLANT IN SERVICE BY ACCOUNTS AND SUBACCOUNTS

COMMON PLANT
($000 Omitted)

Line No.	FERC Acct. No.	Company Acct. No.	Account Title	Note 1 13 Month Average Adjusted as of Mar 31, 2019 (a) $	Note 2 13 Month Average Adjusted as of Dec 31, 2007 (b) $	Utility Plant Investment since 2006 rate case (a) - (b) $
1		1030	Miscellaneous Intanbile Plant	22,332	16,539	5,793
2		1701	Leased AMI Meters	0	0	0
3		1890	Land and Land Rights	154	154	0
4		1900	Structures & Improvements	11,174	3,903	7,271
5		1910	Office Furniture & Equipment	719	398	321
6		1911	Office Furniture & Equipment - EDP Equipment	793	0	793
7		1940	Tools, Shop & Garage Equipment	117	186	(69)
8		1970	Communication Equipment	7,709	39	7,670
9		1980	Miscellaneous Equipment	42	11	31
10			Completed Construction Not Classified	0	6,570	(6,570)
11			Total Common Plant	43,039	27,800	15,239
12			Total Electric/Common Plant	1,742,542	1,129,525	613,017
13		72.82%	Common Plant Allocated to Electric	31,341	21,097	10,244
14			Total Electric Plant Including Allocated Common	1,730,844	1,122,822	**608,022**

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-018

REQUEST:

Refer to the Henning Testimony, page 35, lines 5-11. Provide the annual amount of vegetation management expense for the five years ending in 2016, the base period, and the test year.

RESPONSE:

Period	Distribution	Transmission	Total
2012	1,595,813	178,645	1,774,458
2013	2,011,292	191,717	2,203,009
2014	2,123,558	185,715	2,309,273
2015	1,930,287	125,297	2,055,584
2016	1,812,789	242,781	2,055,570
Base Period	1,370,074	230,941	1,601,015
Test Year	4,036,724	443,163	4,479,887

PERSON RESPONSIBLE: Robert H Pratt/David Doss

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-019

REQUEST:

Refer to the Henning Testimony, page 35, lines 15-20.

a. Provide the cost for meter reading, customer-service calls and call center operations for 2015, 2016, 2017 year-to-date, the base period, and the test period.

b. Provide the cost savings Duke Kentucky has incurred from meter reading, customer-service calls, and call center operations since it began deploying AMI technology. Consider this an ongoing request throughout this proceeding.

c. Provide the amount of cost savings from meter reading, customer-service calls, and call center operations reflected on the base period and test period.

d. Provide the amount of annual incremental cost savings from meter reading, customer-service calls, and call center operations after the test period based upon full deployment of the AMI technology.

RESPONSE:

a. Please see STAFF DR 02-019a ATTACHMENT.

b. The cost savings that the Company has reflected in the test period are shown in WPD-2.26a. Of the planned cost savings shown on that workpaper, the savings that have been realized so far relate only to "Reduced meter operations costs – field metering labor" and total $27,179 through September 2017.

c. Duke Energy Kentucky's estimated cost savings from the AMI deployment for meter reading and other categories were incorporated as pro forma adjustments in this case as shown in Schedule D-2.26 (further supported by WPD-2.26a).

d. See response to STAFF-DR-02-019(c).

PERSON RESPONSIBLE: Sarah E. Lawler/Don Schneider

Description	2015	2016	September 2017 YTD	Base Period	Test Period
Meter Reading	$ 1,349,007	$ 1,267,124	$ 1,013,419	$ 1,392,920	$ 847,772
Customer Care Operations (1)	$ 1,292,049	$ 1,383,090	$ 1,193,326	$ 1,537,979	$ 1,747,359

(1) Includes costs for customer service calls and call center operations

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-020

REQUEST:

Refer to the Direct Testimony of Lisa M. Bellucci ("Bellucci Testimony"), page 4. Provide the calculation of the combined federal and state statutory income tax rate of 38.47 percent.

RESPONSE:

As shown in Schedule H, page 2 of 2, state income taxes are calculated by apportioning income subject Kentucky state income tax.

89.0867% of Duke Energy Kentucky's income is subject to Kentucky's 6% Income Tax and State income tax is deductible for computing federal income tax.

Therefore, the calculation of the combined statutory effective income tax rate is:

(Ky Income Tax Rate * Apportionment Share) + (Federal Income Tax Rate * (1 – Apportioned Ky Income Tax Rate) or

[6% * 89.0867%] + [35% * {1 – (6% * 89.0867%)}] = 38.47%

PERSON RESPONSIBLE: Lisa M. Belluci

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

PUBLIC STAFF-DR-02-021 (As to Attachment Only)

REQUEST:

Refer to the Bellucci Testimony, page 5.

a. Provide a copy of Duke Kentucky's 2016 (12/31/2015) and 2017 Public Service Company Property Tax Assessment from the Kentucky Department of Revenue.

b. Provide a copy of Duke Kentucky's 2016 and 2017 Ohio real and personal property tax assessment when they become available.

c. Provide the actual property tax paid in Kentucky and Ohio for the most recent year that information is available.

d. Provide an electronic copy of the calculation of the property tax for the base period and test year in Excel spreadsheet format with all formulas intact.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment Only)

a. See "STAFF-DR-02-021(a) CONFIDENTIAL ATTACHMENT" (being filed under seal of a Petition for Confidential Treatment) for Duke Energy's 2016 Notice of Assessment, which includes value for both Gas and Electric. The 2017 KY Assessment Notice has not been completed and is not available at this time.

b. See "STAFF-DR-02-021(b) ATTACHMENT 1" for Duke Energy Kentucky 2016 Ohio personal property tax assessment. See "STAFF-DR-02-021(b) ATTACHMENT 2" for Duke Energy Kentucky's 2016 Ohio personal property tax paid in 2017. See

"STAFF-DR-02-021(b) ATTACHMENT 3" for DEK's 2016 Ohio real property tax assessment paid in 2017. See "STAFF-DR-02-021(b) ATTACHMENT 4" for Duke Energy Kentucky's 2017 Ohio personal property tax assessments. Duke Energy Kentucky's 2017 Ohio real property tax assessments have not been issued and are not available at this time.

c. See "STAFF-DR-02-021(c) ATTACHMENT 1" for Duke Energy Kentucky's Ohio 2016 tax year property taxes paid in 2017. See "STAFF-DR-02-021(c) ATTACHMENT 2" for Duke Energy Kentucky's Kentucky 2015 property taxes paid in 2016. This includes payments for both Gas and Electric assets in Kentucky.

d. Please see AG-DR-01-041 ATTACHMENT A.

PERSON RESPONSIBLE: Cooper Monroe

STAFF-DR-02-021(a) CONFIDENTIAL ATTACHMENT IS BEING FILED UNDER SEAL OF A PETITION FOR CONFIDENTIAL TREATMENT

Ohio | Department of Taxation

STATE OF OHIO
DEPARTMENT OF TAXATION

TAXPAYER COPY

PUBLIC UTILITY PROPERTY TAX PRELIMINARY ASSESSMENT

The Tax Commissioner hereby certifies the apportioned personal property tax values for the taxpayer named herein to the county and taxing districts shown below.

DUKE ENERGY KENTUCKY, INC.

550 S. TRYON ST.
PO BOX 1321 (DEC41B)
CHARLOTTE, NC 28201

FEIN: [redacted]
CLASS: ELECTRIC COMPANY
YEAR: 2016
COUNTY: BUTLER 9
DATE: October 03 , 2016

	TAXING DISTRICT	PERSONAL PROPERTY Assessed Value
0180	MADISON TWP-EDGEWOOD CSD	33,140,030
	BUTLER COUNTY TOTAL:	33,140,030

NOTICE TO TAXPAYER: This is not a tax bill. Send remittance to the County Treasurer upon receipt of tax bill. In the event you object to this assessment, see attached instructions.

Joseph W. Testa
Tax Commissioner

Sup. Initial
JPM

Ohio | Department of Taxation

STATE OF OHIO
DEPARTMENT OF TAXATION

TAXPAYER COPY

PUBLIC UTILITY PROPERTY TAX PRELIMINARY ASSESSMENT

The Tax Commissioner hereby certifies the apportioned personal property tax values for the taxpayer named herein to the county and taxing districts shown below.

DUKE ENERGY KENTUCKY, INC.

550 S. TRYON ST.
PO BOX 1321 (DEC41B)
CHARLOTTE, NC 28201

FEIN: [redacted]
CLASS: ELECTRIC COMPANY
YEAR: 2016
COUNTY: HAMILTON 31
DATE: October 03 , 2016

	TAXING DISTRICT	PERSONAL PROPERTY Assessed Value
0560	MIAMI TWP-THREE RIVERS LSD	257,740
1110	CINCINNATI CORP-CINCINNATI CSD	86,280
	HAMILTON COUNTY TOTAL:	344,020

NOTICE TO TAXPAYER: This is not a tax bill. Send remittance to the County Treasurer upon receipt of tax bill In the event you object to this assessment, see attached instructions

BO ELECTRIC /11/2016 7 11 05 AM BO 00% 33464250

Joseph W. Testa
Tax Commissioner

Sup. Initial
JPM

2016 DEK Ohio Personal Property Assessments (paid in 2017)

County	Parcel	Tax Assessment	Tax Paid
Butler County, OH	Madison TWP-Edgewood CSD	33,140,303	2,255,510.46
Hamilton County, OH	Miami TWP-Three Rivers LSD	257,740	22,219.76
Hamilton County, OH	Cincinnati Corp-Cincinnati CSD	86,280	9,562.42

2016 DEK Ohio Real Property Assessments (paid in 2017)

County	Parcel	Tax Assessment	Tax Paid
Butler County, OH	E2310-007-000-002	131,950	13,746.72
Butler County, OH	E2310-008-000-015	1,936,890	118,723.36
Hamilton County, OH	570-0260-0028-00	2,140	303.27

Ohio | Department of Taxation

STATE OF OHIO
DEPARTMENT OF TAXATION

TAXPAYER COPY

PUBLIC UTILITY PROPERTY TAX PRELIMINARY ASSESSMENT

The Tax Commissioner hereby certifies the apportioned personal property tax values for the taxpayer named herein to the county and taxing districts shown below.

DUKE ENERGY KENTUCKY, INC.

550 S. TRYON ST.
PO BOX 1321 (DEC41B)
CHARLOTTE, NC 28201

FEIN: [redacted]
CLASS: ELECTRIC COMPANY
YEAR: 2017
COUNTY: BUTLER 9
DATE: October 02 , 2017

	TAXING DISTRICT	PERSONAL PROPERTY Assessed Value
0180	MADISON TWP-EDGEWOOD CSD	33,230,300
	BUTLER COUNTY TOTAL:	33,230,300

NOTICE TO TAXPAYER: This is not a tax bill. Send remittance to the County Treasurer upon receipt of tax bill. In the event you object to this assessment, see attached instructions.

BO ELECTRIC 10/2017 12 30 02 PM BO 00% 33436750

Joseph W. Testa
Tax Commissioner

Sup. Initial
JPM

Ohio | Department of Taxation

STATE OF OHIO
DEPARTMENT OF TAXATION

TAXPAYER COPY

PUBLIC UTILITY PROPERTY TAX PRELIMINARY ASSESSMENT

The Tax Commissioner hereby certifies the apportioned personal property tax values for the taxpayer named herein to the county and taxing districts shown below.

DUKE ENERGY KENTUCKY, INC.

550 S. TRYON ST.
PO BOX 1321 (DEC41B)
CHARLOTTE, NC 28201

FEIN: [redacted]
CLASS: ELECTRIC COMPANY
YEAR: 2017
COUNTY: CLERMONT 13
DATE: October 02 , 2017

	TAXING DISTRICT	PERSONAL PROPERTY Assessed Value
0420	UNION TWP-WEST CLERMONT LSD	1,390
	CLERMONT COUNTY TOTAL:	1,390

NOTICE TO TAXPAYER: This is not a tax bill. Send remittance to the County Treasurer upon receipt of tax bill. In the event you object to this assessment, see attached instructions.

BO ELECTRIC 15/2017 12 30 02 PM BO 00% 33438750

Joseph W. Testa
Tax Commissioner

Sup. Initial
JPM

Ohio | Department of Taxation

STATE OF OHIO
DEPARTMENT OF TAXATION

TAXPAYER COPY

PUBLIC UTILITY PROPERTY TAX PRELIMINARY ASSESSMENT

The Tax Commissioner hereby certifies the apportioned personal property tax values for the taxpayer named herein to the county and taxing districts shown below.

DUKE ENERGY KENTUCKY, INC.

550 S. TRYON ST.
PO BOX 1321 (DEC41B)
CHARLOTTE, NC 28201

FEIN: [redacted]
CLASS: ELECTRIC COMPANY
YEAR: 2017
COUNTY: HAMILTON 31
DATE: October 02 , 2017

	TAXING DISTRICT	PERSONAL PROPERTY Assessed Value
0560	MIAMI TWP-THREE RIVERS LSD	56,170
1110	CINCINNATI CORP-CINCINNATI CSD	148,890
	HAMILTON COUNTY TOTAL:	205,060

NOTICE TO TAXPAYER: This is not a tax bill. Send remittance to the County Treasurer upon receipt of tax bill. In the event you object to this assessment, see attached instructions.

BO - ELECTRIC 15/2017 12 30 02 PM BO 00% 33438750

Joseph W. Testa
Tax Commissioner

Sup. Initial
JPM

Duke Energy Kentucky, Inc.
Ohio 2016 Tax year Paid in 2017

Parcel Type	Statement / Parcel	Assessment	Tax Paid
Electric-Personal Property			
TREASURER OF BUTLER CO OHIO (DEK)	E2310-999-010-400 / 0000090180 : Old BT-22[ELECTRIC]	33,140,030.00	2,255,510.46
Real Property			
	Woodsdale Rd. [E2310-007-000-002] / E2310-007-000-002	131,950.00	13,746.72
	Woodsdale Rd. [E2310-008-000-015] / E2310-008-000-015	1,936,890.00	118,723.36
Total for Real Property:		2,068,840.00	132,470.08
Electric-Personal Property			
TREASURER OF HAMILTON COUNTY (DEK)	31-0111 [ELECTRIC] / 0000311110 : Old H-43[ELECTRIC]	86,280.00	9,562.42
TREASURER OF HAMILTON COUNTY (DEK)	31-0560 [ELECTRIC] / 0000310560 : Old H-37[ELECTRIC]	257,740.00	22,219.76
Total for Electric-Personal Property:		344,020.00	31,782.18
Real Property	Miami Fort land RE Bill / 570-0260-0028-00	2,140.00	303.27
Total for Ohio:		35,555,030.00	2,420,065.99

Duke Energy Kentucky
TAX YEAR 2015 PAY 2016

Taxing District	County	Date Due	Total
Boone County Sheriff	BOONE	12/23/2015	1,459,091.99
Boone County Sheriff 035-20-00-051.02 Graves Rd	BOONE	11/1/2015	1,363.61
City of Florence	BOONE	12/23/2015	89,606.46
City of Union	BOONE	2/29/2016	1,530.81
City of Union 201-00-00-000.01	BOONE	3/1/2016	4,399.05
City of Walton	BOONE	12/23/2015	6,956.53
	BOONE Total		1,562,948.45
Bracken County Sheriff	BRACKEN	4/30/2016	4,150.92
	BRACKEN Total		4,150.92
Campbell County Sheriff	CAMPBELL	6/13/2016	1,002,558.62
Campbell County Sheriff 999-99-05-264.00	CAMPBELL	2/6/2016	173.30
City of Alexandria (real property only)	CAMPBELL	3/9/2016	9,474.07
City of Bellevue	CAMPBELL	6/16/2016	31,031.22
City of Cold Spring	CAMPBELL	6/20/2016	8,694.51
City of Crestview	CAMPBELL		2,387.97
City of Dayton	CAMPBELL	6/17/2016	48,302.85
City of Ft Thomas	CAMPBELL	6/16/2016	88,331.50
City of Ft. Thomas School- we get this bill sepatate	CAMPBELL	6/16/2016	223,303.28
City of Highland Heights	CAMPBELL	6/17/2016	8,817.48
City of Melbourne	CAMPBELL	8/18/2016	2,814.84
City of Newport	CAMPBELL	6/9/2016	307,605.19
City of Newport- 999-99-05-264	CAMPBELL	10/31/2015	647.66
City of Silver Grove	CAMPBELL	6/17/2016	1,823.96
City of Southgate	CAMPBELL	12/12/2015	62,595.43
City of Wilder	CAMPBELL	6/20/2016	11,994.78
City of Woodlawn	CAMPBELL		738.00
	CAMPBELL Total		1,811,294.66
Kentucky State Treasurer	DE Kentucky	1/8/2016	1,706,266.75
Kentucky State Treasurer- watercraft	DE Kentucky	4/18/2016	3,769.12
	DE Kentucky Total		1,710,035.87
City of Glencoe	GALLATIN		40.38
City of Warsaw	GALLATIN	12/18/2015	1,203.65
Gallatin County	GALLATIN	12/23/2015	18,283.04
	GALLATIN Total		19,527.07
City of Crittenden	GRANT	12/26/2015	2,942.74
City of Dry Ridge-	GRANT	12/15/2015	7,540.16
City of Williamstown	GRANT	12/15/2015	5,467.55
Grant County	GRANT	12/29/2015	116,564.15
Grant County- fire fees- Crittenden	GRANT	10/9/2015	24.50
Grant County-Real- 034-00-00-020.00 & Dry Ridge fire fee	GRANT	10/9/2015	483.26
	GRANT Total		133,022.36
City of Covington	KENTON	12/23/2015	214,027.45
City of Covington- real estate 055.11.14.001.01 waste fee	KENTON	3/30/2015	75.00
City of Covington- real estate 055.11.14.001.02 waste fee	KENTON	3/30/2015	75.00
City of Covington- real estate 055.11.14.001.09 waste fee	KENTON	3/30/2015	75.00
City of Covington- real estate 055.11.14.009.00 4 waste units	KENTON	10/14/2015	300.00
City of Crescent Springs	KENTON	5/20/2016	7,843.59
City of Crestview Hills	KENTON	12/31/2016	5,010.00
City of Crestview Hills- real 029.10.00.001.02	KENTON	12/31/2015	1,046.50
City of Edgewood	KENTON	5/23/2016	23,653.28
City of Elsmere	KENTON	6/16/2016	15,953.18
City of Erlanger	KENTON	5/22/2016	87,106.06
City of Fort Mitchell-	KENTON	6/1/2016	10,101.89
City of Fort Mitchell-Beechwood SD	KENTON	6/1/2016	75,122.10
City of Ft Wright	KENTON	5/19/2016	29,545.85
City of Independence	KENTON	5/20/2016	55,759.98
City of Lakeside Park	KENTON	6/5/2016	25,171.06
City of Park Hills	KENTON	5/20/2016	18,213.28
City of Ryland Heights	KENTON	9/28/2016	3,559.76
City of Taylor Mill	KENTON	5/20/2016	46,706.06
City of Villa Hills	KENTON	10/5/2016	12,199.95
Erlanger-Elsmere Bd of Ed.	KENTON	5/21/2016	206,366.33
Kenton County Sheriff	KENTON	5/19/2016	2,287,971.72

Duke Energy Kentucky
TAX YEAR 2015 PAY 2016

Taxing District	County	Date Due	Total
Kenton County Sheriff 040-34-04-0007.00 fire fee 600 2nd St	KENTON	2/3/2016	60.00
Kenton County Sheriff 001-00-00-015.00 fire fee 3020 Amsterdam Rd.	KENTON	2/3/2016	60.00
Kenton County Sheriff 024-00-00-011.00 fire fee 284 Eads Rd	KENTON	2/3/2016	60.00
Kenton County Sheriff 026-43-03-011.01 fire fee Sleepy Hollow Rd.	KENTON	2/3/2016	60.00
Kenton County Sheriff 027-20-03-022.00 fire fee 2445 Bromley Crescent Springs	KENTON	2/3/2016	60.00
Kenton County Sheriff 029-10-00-001.02- 2612 Thomas Moore Pkwy	KENTON	10/26/2016	6,690.41
Kenton County Sheriff 029-10-00-001.02- fire fee C of Crestview H.	KENTON	11/1/2015	6,690.41
Kenton County Sheriff 029-20-01.018.00 fire fee Turkeyfoot Rd.	KENTON	2/3/2016	60.00
Kenton County Sheriff 040-11-08-001.00 fire fee 109 Highway Ave	KENTON	2/3/2016	60.00
Kenton County Sheriff 040-13-00-001.01 fire fee 50 River Rd.	KENTON	2/3/2016	60.00
Kenton County Sheriff 042-40-00-006.00 fire fee 500 Brooks St.	KENTON	2/3/2016	60.00
Kenton County Sheriff 044-20-00-071.00 fire fee 4145 Madison Pk	KENTON	2/3/2016	60.00
Kenton County Sheriff 048-00-00-139.00 fire fee 11749 Taylor Mil Rd	KENTON	2/3/2016	60.00
Kenton County Sheriff 054-23-20-001.00 fire fee 300 10th St.	KENTON	2/3/2016	60.00
Kenton County Sheriff 055-12-02-024.00 fire fee 508 Hawthorne St.	KENTON	2/3/2016	60.00
Kenton County Sheriff 055-12-02-082.00 fire fee 517 Hawthorne St	KENTON	2/3/2016	60.00
Kenton County Sheriff 055-13-02-010.02 fire fee 1820-32 Russell St	KENTON	2/3/2016	60.00
Kenton County Sheriff 055-14-07-001.00 fire fee 1902-30 Augustine St.	KENTON	2/3/2016	60.00
Kenton County Sheriff 055-41-14-006.02 fire fee 2226 Oakland Ave	KENTON	2/3/2016	60.00
Kenton County Sheriff 069-20-00-011.00 fire fee 8096 Decoursey Pk	KENTON	2/3/2016	60.00
Kenton County Sheriff 055.11.14.006.00 911 fee	KENTON	12/7/2015	60.00
Kenton County Sheriff 055-11-14-001.01 411-17 Watkins St 911	KENTON	10/9/2015	60.00
Kenton County Sheriff 055-11-14-002.00 409 Watkins St	KENTON	10/9/2015	60.00
Kenton County Sheriff 055-11-14-008.00 408 13th St	KENTON	10/9/2015	60.00
Kenton County Sheriff 055-11-14-009.00 410 13th St	KENTON	10/9/2015	60.00
	KENTON Total		3,140,643.86
City of Butler	PENDLETON	4/22/2016	3,096.36
City of Falmouth	PENDLETON	9/29/2016	18,375.56
Pendleton County Sheriff	PENDLETON	1/18/2016	57,624.15
	PENDLETON Total		79,096.07
	Grand Total		8,460,719.26

Butler County (Ohio)	BUTLER-OHIO	3/3/2016	2,313,738.00
Hamilton County (Ohio)	HAMILTON-OHIO	2/1/2016	515,337.00
Total Ohio			2,829,075.00
Grand Total DEK			11,289,794.26

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-022

REQUEST:

Refer to the Direct Testimony of David L. Doss, Jr. ("Doss Testimony"), page 5, regarding the proposed regulatory deferrals.

a. Explain Duke Kentucky's position regarding risk shifting from Duke Kentucky to its customers.

b. Is Duke Kentucky aware of any other Kentucky electric utility that uses regulatory deferrals for O&M expenses related to planned generation maintenance outages? If so, identify the utility.

c. Is Duke Kentucky aware of any other Kentucky electric utility that uses a regulatory deferral for replacement power expenses related to forced outages? If so, identify the utility.

RESPONSE:

a. Mr. Doss does not discuss "risk shifting" in the referenced testimony. The discussion on page 5 relates to the Company's proposal to ensure that customers pay no more or less than the cost of planned outages. Insofar as the Company's expenses are always subject to prudence reviews by the Commission, the Company bears the risks of ensure that its costs for planned outages are reasonable and prudent. Traditional ratemaking principles provide that the Company be allowed to recover its actual, prudent and reasonable expenses

required to serve its customers; therefore, customers are bearing no more risk with the proposed deferral than they would without the deferral.

b. Yes. In Case No. 2016-00370 and 2016-00371, the Commission approved a stipulation for LG&E and KU that included a similar deferral mechanism. See Commission's Order in the referenced cases, Appendix A, page 6.

c. The Company is not aware of another Kentucky utility that uses deferral accounting for this item; however, it is aware that Kentucky Power currently recovers such costs via its PPA rider and is proposing to continue such recovery as part of its pending rate case, Case No. 2017-00179. (Direct Testimony of Kentucky Power witness Vaughn, page 6).

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-023

REQUEST:

Refer to the Doss Testimony, page 5, lines 13-14, and the Direct Testimony of Robert H. "Beau" Pratt ("Pratt Testimony"), page 21, lines 4-6.

a. Explain the discrepancy in the testimony of the witnesses listed above as to the timeframe utilized for developing outage and production maintenance expenses in the test year.

b. Provide the actual fiscal/calendar years used to determine the "average" outage and production maintenance expenses.

c. Refer to the Pratt Testimony, page 21. What was the amount of production maintenance expense included in the forecast and why was it understated?

d. Confirm there are no outage and production maintenance expenses related to Miami Fort Unit 6 included in the years utilized for the proposed amount of the outage/production maintenance expense.

e. Provide the forecasted outage/production maintenance expense by account number for the six years included in the Application and for each year through March 2025.

f. Provide a history of the date and cost of generator overhauls by account number for each unit by year since 2006.

g. Provide a schedule showing the date and cost of future generator overhauls by account number by year through 2025.

h. Provide a history of the date and cost of turbine overhauls by account number for each unit by year since 2006.

i. Provide a schedule showing the date and cost of future turbine overhauls by account number by year through 2025.

RESPONSE:

a. The Pratt Testimony referenced refers to the East Bend total maintenance expense proforma adjustment shown on Schedule D-2.30, and was made to correct an understated budget. This proforma adjustment used a five year average of actual data for the years 2012 through 2016. The Doss Testimony referenced refers to an outage expense adjustment, a portion of total maintenance expense, shown on Schedule D-2.33 which was made to normalize planned outage expenses. This proforma adjustment used a six year average consisting of four years of actual data, years 2013 through 2016, and two years of projected data, years 2017 and 2018.

b. See response to item a.

c. As shown on WPD-2.30a, the amount of East Bend maintenance expense included in the forecasted test period was $5,575,440. This amount was based on a budget that was erroneously understated as can be evidenced by the historical data used in determining proforma adjustment D-2.30.

d. Confirmed.

e. See STAFF-DR-02-23e Attachment for details supporting planned outage expense by account number for 2013-2021. The company has not prepared a forecast for periods beyond 2021.

f. None.

g. None.

h. There was one turbine overhaul since 2006 at East Bend Unit 2 and the O&M costs were as follows:

    a. 2007 spend – Acct 513 – $653,175

    b. 2008 spend – Acct 513 – $883,224

i. Through 2021, there is one turbine overhaul planned for the spring of 2018. Forecasting is completed for a five year period and, as such, forecasted data is not available beyond 2021. O&M details of the 2018 turbine overhaul are as follows:

    a. 2017 projected spend – Account 513 – $148,622

    b. 2018 projected spend – Account 513 – $3,774,163

PERSON RESPONSIBLE: Robert H. Pratt / David L. Doss, Jr.

Forecasted outage/production maintenance expense by account number

East Bend

Account	2013	2014	2015	2016	2017	2018	2019	2020	2021
500	637	93	-	1,827	-	-	-	-	-
506	-	2,972	-	26,477	-	-	-	-	-
510	-	6,539	-	631	-	-	-	-	-
511	77,329	106,560	6,611	173,083	-	-	-	-	-
512	3,016,791	8,631,694	2,735,845	4,989,198	739,672	6,854,375	-	4,323,819	4,969,923
513	851,328	5,146,747	101,415	606,932	216,761	5,255,302	-	1,267,096	1,456,437
514	100,862	103,903	6,296	3,043,657	2,918	2,966	-	17,057	19,606
921	-	-	-	85	-	-	-	-	-
925	-	-	-	1,427	-	-	-	-	-
926	53,419	64,386	17,886	54,203	446	453	-	2,607	2,997
	4,100,366	14,062,894	2,868,053	8,897,520	959,797	12,113,096	-	5,610,579	6,448,963

Woodsdale

Account	2013	2014	2015	2016	2017	2018	2019	2020	2021
553	-	-	-	2,271,112	4,529,358	-	-	838,384	-

Notes

a) 2013-2018 reference WPD-2.33a

b) Forecasting is completed for a 5-year period. Forecast is available for 2017-2021 and does not extend to 2025.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-024

REQUEST:

Refer to the Doss Testimony, page 7. Provide any FERC guidance or accounting principles that support inclusion of carrying charges in regulatory assets.

RESPONSE:

There are many examples in which the FERC has supported the inclusion of carrying costs as part of regulatory assets. For instance, in its order dated July 16, 2009 in Docket No. ER08-1540-001, FERC ruled:

> *"Carrying charges reflect the time value of money, i.e., the interest on the deferred costs from the time of incurrence until the time at which those funds are recovered. Recovery of these charges is necessary to ensure that Dominion receives compensation for the costs that it has incurred and the time value of not recovering these costs earlier."*

More recently, in its order dated October 6, 2017 in Docket No. EL17-52-000, FERC responded to Republic Transmission, LLC's request to accrue carrying charges on a regulatory asset by ruling:

> *"We also will grant Republic's request for authorization to accrue a carrying charge from the effective date of the asset until the asset is included in its rate base."*

In addition, the Kentucky Public Service Commission ("the Commission") has shown that it agrees with the FERC in this regard, as evidenced in its previous rulings involving the Company. For example, in its December 15, 2015 order in Case No. 2015-00187, in which the Commission approved the Company's request for approval of a regulatory

asset for the liabilities associated with ash pond asset retirement obligations, the Commission ordered that:

> *"The accounting treatment requested by Duke Kentucky to defer appropriate carrying charges on its unamortized CCR Compliance Regulatory Asset, as described herein, is approved for 2015 and subsequent years."*

Clearly, both the FERC and the Commission recognize that the time value of money represents a true cost to the utility and that it is appropriate to include such cost in regulatory assets.

PERSON RESPONSIBLE: David Doss

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-025

REQUEST:

Refer to the Direct Testimony of Tammy Jett ("Jett Testimony"), page 6.

a. Explain whether Duke Kentucky maintains an inventory of emission allowances on its books. If so, provide the account number and the current balance broken down by type allowance.

b. Provide the current per unit cost of allowances in inventory by type of emission allowance and the current market prices of those same allowances.

RESPONSE:

a. Yes. Emission allowance inventory is recorded in Accounts 158.1 and 158.2.

Emission Allowance Inventory		
		9/30/2017
Account	Account Description	Ending Balance
0158150	SO2 Current Vintage	$ 17,587
0158170	Annual NOx Current Vintage	8,408
0158183	Seasonal NOx Current	8,591
	Total	**$ 34,586**

b. For the Emission Allowances held by Duke Energy Kentucky, unit costs and current market values are as follows:

Emission Allowance Information				
	9/30/2017	10/31/2017 Market Values		
Program	Unit Cost	Bid	Ask	Mid
5O2 Current Vintage	$0.20	$0.25	$0.75	$0.50
Annual NOx Current Vintage	2.48	2.00	3.00	2.50
Seasonal NOx Current	$9.86	$165.00	$200.00	$182.50

PERSON RESPONSIBLE: David Doss

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-026

REQUEST:

Refer to the Jett Testimony, page 16. Provide the estimated cost of each project that Duke Kentucky is proposing to include in its environmental compliance plan. Also, provide a description of the reagent inventories to be included in the proposed compliance plan.

RESPONSE:

Please see Attachment JAM-1, page 1 of 2, for current estimated costs of each project that Duke Kentucky is proposing to include in its environmental compliance plan. No reagent inventories are included in the compliance plan. Reagents (Ammonia, Limestone and Trona) to be included in the Company's Rider ESM are O&M expense only as shown on Attachment SEL-2, page 9 of 10.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 27, 2017

STAFF-DR-02-027

REQUEST:

Refer to the Direct Testimony of Sarah E. Lawler Testimony ("Lawler Testimony"), page 13.

a. Explain how Duke Kentucky determined the ten-year amortization period for the regulatory assets associated with the incremental operations and maintenance expenses at the East Bend Generating Station ("East Bend"), the incremental retirement costs associated with the retirement of Miami Fort Unit 6 Generation Station, the carrying costs on the unrecovered balance based upon Duke Kentucky's actual cost of debt, and any other incremental costs related to the assumed liabilities or otherwise necessary to effectuate the purchase of East Bend.

b. Explain why it would not be appropriate to amortize the regulatory assets over the remaining life of East Bend.

RESPONSE:

a. Because of the magnitude of this regulatory asset, the Company weighed its interest in timely recovery against the interest of mitigating the impact on customers' bills and determined that a ten-year amortization struck a reasonable balance between these competing interests.

b. The incremental O&M expenses at East Bend relate to costs incurred from the time of the acquisition through the last day preceding the test period. For the

reasons noted in the company's response to Staff-DR-02-027(a), the company believes a ten-year amortization to be reasonable.

PERSON RESPONSIBLE: William Don Wathen Jr. (a)
Sarah E. Lawler (b)

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-028

REQUEST:

Refer to the Lawler Testimony beginning on page 17. Provide the overall financial impact of the proposed changes to Duke Kentucky's Profit Sharing Mechanism, Rider PSM, based on the 2016 actual results, for 2016, 2017 to date, the base period, and the test period.

RESPONSE:

Recalculating Rider PSM results in the following impacts to customers and the Company.

Period	Impact to Customers	Tax Impact @ 38.47%	Financial Impact
2016 PSM	800,973	308,134	(492,839)
YTD 2017 PSM	1,222,940	470,465	(752,475)
Base Period	542,036	208,521	(333,515)
Forecasted Period	322,294	123,987	(198,307)

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-029

REQUEST:

Refer to the Lawler Testimony, Attachment SEL-2, page 3 of 10.

a. Explain whether Duke Kentucky is proposing to update this form with each monthly filing, during the six-month and two-year reviews of its environmental surcharge mechanism, or with base rate changes.

b. Explain why Duke Kentucky is excluding "uncollectible accounts expense and KPSC maintenance tax factors" from the gross revenue conversion factor.

RESPONSE:

a. The Company is proposing to update this form only when it files a base rate case.

b. The Company excluded "uncollectible accounts expense and KPSC maintenance tax factors" from the gross revenue conversion factor used in Attachment SEL-2, page 3 of 10, so that the gross up factor would only reflect state and federal taxes.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-030

REQUEST:

Refer to the Lawler Testimony, Attachment SEL-2, page 4 of 10; the Application, Volume 13, Tab L, Schedule L-1, page 83 of 148; and the Direct Testimony of Tammy Jett at page 17, which explains that Duke Kentucky "is seeking authorization to include consumables inventories such as reagents and emission allowances" in its environmental surcharge. Confirm that reagent inventories are not included in the proposed calculation of environmental rate base.

RESPONSE:

As shown on Attachment SEL-2, page 4 of 10 and the Application, Volume 13, Tab L, Schedule L-1, page 83 of 148, only emission allowance inventory is included in the proposed calculation of environmental rate base. It is not the company's intention to include reagent inventories in the environmental surcharge mechanism. The words "reagents and" as noted above should not have been included in Ms. Jett's testimony. Recovery of reagent O&M expense however is included in the environmental surcharge mechanism as noted on Attachment SEL-2, page 9 of 10.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-031

REQUEST:

Refer to the Lawler Testimony, Attachment SEL-2, page 4 of 10 and the Application, Volume 13, Tab L, Schedule L-1, page 84 of 148.

a. Confirm that the proposed tariff language indicates that the over- or under-recovery is a "one-month 'true-up' adjustment" but the proposed environmental surcharge report form calculates the over- or under-recovery based on the authorized revenue requirement from two months prior.

b. State whether Duke Kentucky is proposing a one-month or two-month "true-up" adjustment for its over- or under-recovery.

RESPONSE:

a. The proposed tariff language indicates that the over- or under-recovery is a "one-month 'true-up' adjustment". The proposed environmental surcharge report form calculates the over- or under-recovery based on comparing the revenues collected under Rider ESM to the costs to be recovered under Rider ESM for that month. To illustrate, assume Rider ESM for June is implemented to recover $1 million in costs incurred during the month of April, i.e., two months prior. If actual revenue during June (which won't be known until after the month ends) is higher or lower than $1 million, then there will an amount to true-up in the next Rider ESM period. In this example, June results would be known in July and the

true-up would be reflected in the August Rider ESM rates. The August Rider filing would therefore include an (Over)/Under Recovery section comparing E(m) Authorized for Expense Month of April to E(m) Revenue Recovered in June.

b. The company is proposing a one-month true-up.

PERSON RESPONSIBLE: Sarah E. Lawler

STAFF-DR-02-032

REQUEST:

Refer to the Direct Testimony of Jeffrey T. Kopp, Decommissioning Study, page 7 of 30. Did the Decommissioning Study include the assets related to the proposed ultra-low sulfur diesel distillate fuel oil project at the Woodsdale Generating Station ("Woodsdale")?

RESPONSE:

The decommissioning study is based on the equipment and facilities currently installed at Woodsdale plant at the time the study was prepared. The proposed project has not yet received Commission approval.

PERSON RESPONSIBLE: Jeff Kopp

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-033

REQUEST:

Refer to the Direct Testimony of Cynthia S. Lee ("Lee Testimony"), pages 9-12.

a. Explain how the ten-year amortization period for the Asset Retirement Obligation ("ARO") associated with the ash pond closure was determined.

b. Refer to the Lee Testimony, page 8, where it states that the estimated remaining life of East Bend is approximately 23.5 years. Explain why the ARO should not be amortized over the estimated remaining life of East Bend.

RESPONSE:

a. The ten-year period was chosen as a reasonable period of time to allow Duke Energy to recover the majority of the costs necessary to comply with the CCR Rule related to closing the East Bend coal ash basin while at the same time providing ratepayers a reasonable period of time over which to reimburse these costs. The majority of the spend related to this obligation is expected to be complete by 2021, with post-closure maintenance extending through 2049. This ten-year period minimizes the impact to ratepayers by extending the recovery several years beyond the closure of the ash basin. Please note that the costs included in the recovery schedule filed with this testimony exclude closure of the dry ash landfills and post-closure maintenance.

b. The recovery of the costs necessary to comply with the CCR Rule, which are the costs reflected in the ARO, is a separate timing issue from the remaining life of the East

Bend operating plant. Once the ash pond is closed, which is expected to occur by the end of 2019, East Bend will operate using dry ash handling rather than the ash basin. As such, the recovery of the costs associated with the closure of the ash basin are not directly associated with the remaining life of the operating plant and should be recovered sooner than over than remaining life of the East Bend operating plant.

PERSON RESPONSIBLE: Cynthia S. Lee

STAFF-DR-02-034

REQUEST:

Refer to the Lee Testimony, page 11, lines 10-14 and the Lawler Testimony, Attachment SEL-2, pages 9 and 10.

a. Confirm that Duke Kentucky is proposing to recover estimated and previously incurred costs through its environmental surcharge.

b. Explain how recovery of the East Bend Coal Ash ARO through the environmental surcharge complies with the requirement of KRS 278.183(2) that costs recovered through the environmental surcharge be included on customer bills "in the second month following the month in which the costs are incurred."

RESPONSE:

a. Yes. The East Bend Coal Ash ARO that the Company is proposing to amortize and recover through the Environmental Surcharge Mechanism (ESM) is calculated based on costs incurred to-date and not already recovered in base rates, as well as the future estimated costs to be incurred.

b. The ARO represents costs incurred to comply with federal, state, or local environmental regulations related to coal combustion as described in 278.183(1). Consistent with 278.183(2), the recovery of costs pursuant to subsection (1) of 278.183, that are not already included in existing rates shall be by an environmental surcharge to existing rates imposed as a positive or negative

adjustment to the customer bills in the second month following the month in which the costs are incurred. The ARO deferral and the associated accretion and depreciation expense were approved by the Commission in Case No. 2015-00187. The currently pending case is the Company's first base electric rate case since 2006, so the ARO costs are not already included in base rates.

The recovery methodology through an amortization period that Duke Energy Kentucky is requesting minimizes the base rate impact to customers of the costs associated with closing the East Bend ash basin by spreading the recovery of levelized costs over a longer period of time in a transparent manner through the ESM. The Company's proposal is thematically consistent with similar levelization treatment of incremental fuel expense recovered through the Fuel Adjustment Clause (FAC) that is periodically permitted by the Commission so to minimize the volatility of the FAC to customers. As a result, the Company is requesting recovery of the ARO over a period of ten years (2018 – 2028). As outlined on Schedule CSL-1 included in the direct testimony of Cynthia S. Lee, a significant portion of the costs will have already been incurred by the time the first environmental surcharge is filed. The proposed recovery schedule begins in June 2018 with straight-line recovery through May 2028. The Company's proposal provides an extended benefit to the ratepayers by not recovering these costs immediately in the second month following the month in which the costs are incurred where customer would experience higher costs in the nearer term with lower costs in the later years. The Company also believes including the entire ARO in the ESM to be more transparent and less cumbersome than including a

portion of the ARO amortization in base rates and a portion of the ARO amortization in the ESM.

If the Commission does not agree with the Company's proposal to include the total costs of the ARO for recovery in the ESM, then the Company's rate case revenue requirement must then be adjusted to account for the recovery of the ARO balance and amortization in base rates. The incremental costs of retirement should then be recovered through the ESM.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-035

REQUEST:

Refer to the Lee Testimony, page 12, lines 13-18 and Attachment CSL-1. Provide the capitalized interest rates used to calculate the carrying costs shown on Attachment CSL-1. Also, provide the calculation of the carrying costs shown on Attachment CSL-1.

RESPONSE:

Duke Energy Kentucky received approval in December 2015 (Final Order – Case No. 2015-00187) to record and defer these carrying costs. Per this order, carrying costs are based on Duke Energy Kentucky's annual weighted average cost of capital ("WACC"), calculated in a manner similar to its allowance for funds used during construction calculation. The carrying costs are calculated using the WACC and recorded monthly on the unamortized CCR Compliance Regulatory Asset balance.

The carrying costs for the periods through June 2017 were calculated using the actual monthly AFUDC/Capitalized Interest rates. The carrying costs are calculated on a one-month lag due to the timing of availability of the rates (eg. May 2017 AFUDC / Capitalized Interest rates were used for the June 2017 calculation). Note that the rates for May 2015 through December 2015 are constant. This is due to the year-to-date entry that was recorded in December 2015 upon receipt of the final order approving the recording and deferral of these carrying costs. The most current AFUDC/Capitalized Interest rates

available at that time (November 2015 rates) were used for the year-to-date entry. See table below.

	Debt	Equity
May-15	0.0770%	0.1690%
Jun-15	0.0770%	0.1690%
Jul-15	0.0770%	0.1690%
Aug-15	0.0770%	0.1690%
Sep-15	0.0770%	0.1690%
Oct-15	0.0770%	0.1690%
Nov-15	0.0770%	0.1690%
Dec-15	0.0770%	0.1690%
Jan-16	0.1504%	0.4060%
Feb-16	0.0499%	0.0000%
Mar-16	0.1556%	0.3253%
Apr-16	0.1750%	0.3830%
May-16	0.1553%	0.4100%
Jun-16	0.1553%	0.4100%
Jul-16	0.1553%	0.4100%
Aug-16	0.1545%	0.4116%
Sep-16	0.1536%	0.4133%
Oct-16	0.1528%	0.4149%
Nov-16	0.1528%	0.4173%
Dec-16	0.1512%	0.4019%
Jan-17	0.1504%	0.4060%
Feb-17	0.1382%	0.3743%
Mar-17	0.1285%	0.3247%
Apr-17	0.1244%	0.3410%
May-17	0.1366%	0.3776%
Jun-17	0.1423%	0.3890%

For the periods July 2017 through March 2018, the most recently available AFUDC/Capitalized Interest rates were used. At the time of preparation of the proposed recovery calculations, the June 2017 rates were: Debt 0.1317% and Equity 0.3605%.

For the periods April 2018 through May 2028, the carrying costs are derived using the weighted average cost of capital as filed in Schedule J-1, which is sponsored by Witness Jack Sullivan in this rate proceeding. The monthly rates used are: Debt 0.1681% and Equity 0.4136%.

The calculation of the carrying costs in Attachment CSL-1 is based on the debt and equity AFUDC/Capitalized Interest rates applied to the cumulative unrecovered spend and carrying costs, adjusted for the cost of removal credit. This is a monthly calculation rolling forward from the prior month ending balance. See formula:

> Monthly Carrying Costs = (Prior month ending balance of unrecovered costs + COR Credit – current month recovery) x Debt and Equity rates as described above

PERSON RESPONSIBLE: Cynthia S. Lee

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-036

REQUEST:

Refer to the Direct Testimony of Joseph A. Miller, Jr., page 6. Explain whether Duke Kentucky receives a fee for waste received from other Kentucky electric utilities and Ohio-based electric generators. If confirmed, explain whether these revenues are included in Duke Kentucky's income for the base and forecasted test years.

RESPONSE:

Duke Energy Kentucky receives a fee from some electric utilities which is included as an offset to other production expenses in the based period and forecasted test period.

PERSON RESPONSIBLE: Robert H. Pratt

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-037

REQUEST:

Refer to the Direct Testimony of Roger A. Morin, Ph.D. ("Morin Testimony"), pages 6-7. Duke Kentucky has proposed several riders that tend to lower Duke Kentucky's exposure to volatility and risk. Explain whether Duke Kentucky's proposed range for ROE is still recommended and an essential requirement if these riders are approved.

RESPONSE:

Dr. Morin did not adjust his recommended ROE downward in order to account for the impact of riders on the Company's business risks because his recommended ROE for Duke Energy Kentucky is estimated from market information on the cost of common equity for other comparable electric utilities. To the extent that the market-derived cost of common equity for other utility companies already incorporates the impacts of these or similar mechanisms, no further adjustment is appropriate or reasonable in determining the cost of common equity for Duke Energy Kentucky. To do so would constitute double-counting.

Most, if not all, electric utilities in the industry are under some form of rider/adjustment clause/cost recovery/mechanisms. The approval of riders, adjustment clauses, cost recovery mechanisms, and various forms of risk-mitigating mechanisms by regulatory commissions is widespread in the utility business and is already largely embedded in financial data, such as bond ratings, stock prices, and business risk scores.

Moreover, it is important to note that investors generally do not associate specific increments to their return requirements with specific rate structures. Rather, investors tend to look at the totality of risk-mitigating mechanisms in place relative to those in place at comparable companies when assessing risk.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-038

REQUEST:

Refer to Morin Testimony, page 21. Provide any work papers or studies that support that multiplying the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) understates the return expected by the investor.

RESPONSE:

Multiplied the spot dividend yield by one plus one half the expected growth rate (1 + 0.5g) rather than the conventional one plus the expected growth rate (1 + g) understates the return expected by the investor. The fundamental assumption of the plain vanilla annual DCF model used almost universally by expert witnesses is that dividends are received annually at the end of each year and that the first dividend is to be received one year from now. Thus, the appropriate dividend to use in a DCF model is the full prospective dividend (i.e., 1 + g) to be received at the end of the year. Since the appropriate dividend to use in a DCF model is the prospective dividend one year from now rather than the dividend one-half year from now, the (1 + 0.5g) approach understates the proper dividend yield. Use of this adjustment factor creates a downward bias in the dividend yield component, and underestimates the cost of equity. For example, for a spot dividend yield of 4 percent and a growth rate of 5 percent, the estimated dividend yield is 4.1 percent, whereas the correct dividend yield to employ is 4.2 percent, which is 10 basis points higher.

Proponents of the (1 + 0.5g) approach argue that this somehow adjusts for the fact that dividends are paid quarterly. Cutting the growth rate in half has nothing to do with the fact that dividends are paid quarterly, resulting in more frequent compounding of money to investors. If one wishes to account for the quarterly nature of dividend payments, the proper manner to do so is fully discussed and derived in the attached document "*Quarterly Version Of The DCF Model.*"STAFF-DR-2-38 Attachment.

Moreover, Dr. Morin is unaware of any university-level textbook on corporate finance which relies on, or even discusses, the (1 + 0.5g) approach to recognize quarterly dividends. The annual DCF model is clearly predominant in the academic financial literature supported in every textbook on corporate finance of which I am aware. See for example the following classic textbooks:

Richard A. Brealey, Stewart C. Myers, and Franklin Allen, 2017, *Principles of Corporate Finance*, 12th edition, McGraw-Hill Irwin.

Stephen A. Ross, Randolph W. Westerfield, and Jeffrey Jaffe, 2002, *Corporate Finance*, 6th edition, McGraw-Hill Irwin.

Brigham, E.F. and Ehrhardt, M. *Financial Management: Theory and* Practice, 8th ed., Hinsdale, IL: Dryden Press, 2005.

Dr. Morin also points out that multiplying the spot dividend yield by (1 + g) is actually a conservative attempt to capture the reality of quarterly dividend payments and understates the expected return on equity. Use of this method is conservative because the annual DCF model ignores the more frequent compounding of quarterly dividends as shown in the attached document.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

QUARTERLY VERSION OF THE DCF MODEL

Failure to recognize the quarterly nature of dividend payments understates the cost of equity capital by about 20 basis points.

One of the assumptions of the standard DCF model is that dividend payments are made at the end of each year, whereas, in fact, most utilities pay dividends on a quarterly basis. Chapter 11 of Dr. Morin's book, The New Regulatory Finance, provides a full discussion, derivation, and implementation of the quarterly DCF model in regulatory hearings.

The annual DCF model inherently understates the investors' true return because it assumes that all cash flows received by investors are paid annually. By analogy, a bank rate on deposits that does not take into consideration the timing of the interest payments understates the true yield if the customer receives the interest payments more than once a year. The actual yield will exceed the stated nominal rate. Bond yield calculations are also routinely adjusted for the receipts of semi-annual interest payments. What is true for bank deposits and for bonds is equally germane to common stocks.

Appendix 11-A in Dr. Morin's textbook The New Regulatory Finance formally derives the quarterly DCF model, which has the following form:

$$K = \frac{[d_1(1+K)^{3/4} + d_2(1+K)^{1/2} + d_3(1+K)^{1/4} + d_4]}{P_0} + g \qquad (1)$$

where: d_1 , d_2 , d_3 , d_4 = quarterly dividends expected over the coming year
g = expected growth in dividends
P_0 = current stock price
K = required return on equity

Intuitively, the quarterly form of the DCF model described by Equation 1 resembles the standard annual form, but with a slightly modified dividend yield component. Letting

$$D_1' = d_1(1+K)^{3/4} + d_2(1+K)^{1/2} + d_3(1+K)^{1/4} + d_4$$

and substituting in the numerator of the dividend yield in Equation 11-1, the quarterly DCF equation becomes:

$$K = D_1'/P + g \qquad (2)$$

which is very similar to the annual version. One can think of the D_1' term as an augmented D_1 term that simply captures the added time value of money associated with investors receiving successive quarterly dividends and reinvesting them over the remainder of the year at K%. That is to say, during the course of one year, the investor has the value of the first quarter's dividend for 3/4 of the year; the second quarter dividend for 1/2 of the year; the third quarter dividend for 1/4 of the year, and the fourth quarter dividend is received at the end of the year. The numerical example below shows how to implement the quarterly DCF model and estimate the investor's required market return. The example also shows that the annual version of the DCF model understates investor returns by about 20 basis points.

EXAMPLE

The common stock of Northeastern Electric (NE) is trading at $38.00. The dividend is expected to increase annually at a constant rate of 5.0%. The current quarterly dividend rate is $0.48 and has been in effect for two quarters. Thus, an investor buying NE stock expects to receive, in the next year, two more dividends at the existing rate of $0.48 and two dividends at the new rate of $0.48(1 + g). The cost of equity capital is obtained by solving

iteratively the quarterly version of the DCF model in Equation 1 by means of a computer spreadsheet. To solve that equation, the following input data for NE:

$d_1 = \$0.48$
$d_2 = \$0.48$
$d_3 = \$0.48\ (1 + .05\ ) = \$0.5040$
$d_4 = \$0.48\ (1 + .05\ ) = \$0.5040$
$P_0 = \$38.00$
$g = 5.0\%$

are substituted into Equation 1 as follows:

$$K = \frac{[0.48(1+K)^{3/4} + 0.48(1+K)^{1/2} + 0.5040(1+K)^{1/4} + 0.5040]}{\$38.00} + .05$$

The equation is solved iteratively by successive approximations for K, the cost of equity. Here, K = 10.4%. Note that the annual DCF model produces an estimate of 10.20%, which is less than the 10.40% estimate derived from the quarterly DCF model:

$$K = D_1/P_0 + g = \$1.968/\$38.00 + .05 = 10.18\%$$

The difference is attributable to the time value of money associated with receiving quarterly dividends rather than one lump sum dividend at the end of the year.

The annual version of the DCF model typically understates the cost of equity by approximately 20 basis points, depending on the magnitude of the dividend yield component.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-039

REQUEST:

Refer to Moring Testimony, pages 24—5. Provide any work papers or studies that support the idea that utilities will lower their dividend payout ratios over the next several years.

RESPONSE:

Given the record-high capital spending projected for the electric utility industry for the next decade, $100 billion per year, according to some projections, approximately half of which must come from debt issues, it is clear that the other half must come from common equity. To the extent that internal generation of funds will be insufficient to meet the equity requirement, it is reasonable to postulate that the dividend payout will be lowered in order to enhance the internal generation of funds. Historically over the past five years, earnings growth rate has exceed dividend growth rates, that is, the dividend payout has decreased. For example, Duke Energy's payout has averaged about 80% over the past decade and is projected to decrease to approximately 75% by Value Line in 2017 and 2018.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-040

REQUEST:

Refer to the Morin Testimony, page 32. The Capital Asset Pricing Model ("CAPM") inputs the forecasted interest rate on long-term U.S. Treasury bonds.

a. Explain why the risk-free rate for the CAPM is the forecasted interest on long-term U.S. Treasury bonds and not the current interest rate on long-term bonds.

b. Provide Duke Kentucky's position regarding investor's views of interest rate forecasts, especially given that most interest rate forecasts are known to have been incorrect.

RESPONSE:

a. and b.

Dr. Morin relied on projected long-term Treasury interest rates for the simple reason that investors price securities on the basis of long-term expectations, including interest rates. Cost of capital estimates, including CAPM estimates, are prospective (i.e. forward-looking) in nature and must take into account current market expectations for the future. The CAPM is a prospective (i.e., forward-looking) model, and the use of projected long-term Treasury interest rates is entirely appropriate because investors price securities on the basis of long-term expectations, including interest rates. Whether interest rate forecasts are correct or not is irrelevant. Investor expectations were simply not realized in the past.

The fact that forecasts are incorrect is immaterial and is merely a reflection that expectations were not realized over that period of time. Investors' required returns can and do shift over time with changes in capital market conditions, hence the importance of considering interest rate forecasts. The fact that organizations such as Congressional Budget Office, the U.S. Department of Labor, the U.S. Energy Information Administration, HIS (Global Insight), Value Line and Blue Chip devote considerable expertise and resources to developing an informed view of the future, and the fact that investors are willing to purchase such expensive services confirms the importance of economic/financial forecasts in the minds of investors.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

PUBLIC STAFF-DR-02-041
(As to Attachment Only)

REQUEST:

Refer to the Morin Testimony, page 58 and Exhibit RAM-3.

a. Explain whether all combination electric and gas utilities used in the ROE analysis have any cost-recovery mechanism (referred to as a risk mitigator) similar to the proposed FERC Transmission Cost Reconciliation and Distribution Capital Rider.

b. If the response to a. above is negative, explain whether Duke Kentucky believes the list should be revised to include only those that do have such mechanisms.

c. According to the July 28, 2017 publication of The Value Line Investment Survey ("Value Line"), Issue 11, Avista Corporation has accepted a takeover offer and expects the deal to be completed in the second half of 2018. Many analysts exclude utilities from the proxy group that have ongoing involvement in a merger or acquisition. Explain why Avista Corporation was included in the proxy group.

d. According to the August 18, 2017 publication of Value Line, Issue 1, Eversource Energy has agreed to acquire a water utility. Many analysts exclude utilities from the proxy group that have ongoing involvement in a merger or acquisition. Explain why Eversourse Energy was included in the proxy group.

e. Provide the most recently authorized ROE awards and the date of this award for Duke Kentucky's proxy group.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment Only)

a. Edison Electric Institute has published a recent thorough and voluminous survey of risk-mitigating mechanisms in the electric utility industry (see CONFIDENTIAL STAFF-DR-02-041 Attachment (being filed under seal of a Petitition for Confidential Treatment) "Alternative Regulation for Emerging Utility Challenges"), including riders, trackers, and decoupling among many others. As seen in this report, all 23 combination electric and gas utilities and/or their operating utility companies used in Dr. Morin's analysis possess such mechanisms. It is important to note that investors generally do not associate specific increments to their return requirements with specific rate structures. Rather, investors tend to look at the totality of risk-mitigating mechanisms in place relative to those in place at comparable companies when assessing risk. The important point is that the peer companies do possess risk mitigators similar the riders proposed by the Company.

b. See response to a.

c. The acquisition of Avista by Hydro One was announced on July 17, 2017. This was after Dr. Morin prepared his analyses.

d. The acquisition is unlikely to have a significant impact on Eversource's stock price, given Eversource's large market capitalization of $20.0 billion and Aquarion's very small $1.7 billion.

e. As reported on the Value Line sheets for each company in the peer group, the latest allowed ROEs are shown on the table below and average 9.95%. No exact order date is specified. The most recent year decision is used in the table.

Company Name	Authorized ROE
Alliant Energy	10.50%
Ameren Corp.	8.70% - 9.0%
Avista Corp.	9.50%
Black Hills	9.40%
CenterPoint Energy	9.45% - 11.25%
Chesapeake Utilities	n.a.
CMS Energy Corp.	10.10%
Consol. Edison	9.00%
Dominion Resources	10.90%
DTE Energy	10.10%
Duke Energy	10.10%
Eversource Energy	9.80%
Exelon Corp	9.75%
Fortis	8.30% - 10.32%
MGE Energy	10.20%
NorthWestern Corp.	9.80%
PG&E Corp.	10.40%
Public Serv. Enterprise	10.30%
SCANA Corp.	9.70%
Sempra Energy	10.30%
Vectren Corp.	10.15% - 10.40%
WEC Energy Group	9.11% - 9.90%
Xcel Energy Inc.	9.80%
AVERAGE	**9.95%**

Source: Value Line Research Jun 2017

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

STAFF-DR-02-041 CONFIDENTIAL ATTACHMENT IS BEING FILED UNDER SEAL OF A PETITION FOR CONFIDENTIAL TREATMENT

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-042

REQUEST:

Refer to the Morin Testimony, page 65. Dr. Morin addresses Duke Kentucky's size, stating that its size relative to other electric utilities increases investment risk.

a. Confirm that even though Duke Kentucky is relatively smaller in size, it realizes efficiencies and economies of scale through its Duke Energy family of companies.

b. If a. above is confirmed, explain whether these efficiencies and economies of scale reduce the risk exposure of Duke Kentucky.

RESPONSE:

a. and b.

From a bondholder perspective, Duke Kentucky's relationship with its parent is beneficial through a co-insurance effect. To the extent that the cash flows from members of the parent company holding company are less than perfectly correlated, there is a corresponding decrease in default risk, thus reducing the bondholders risk.

From a stockholder perspective, however, the equity cost of subsidiaries must be found on a stand-alone basis. Under this approach, often labeled the Stand-Alone Approach or Subsidiary Approach, the subsidiary is viewed as an independent operating company, and its cost of equity is inferred as the cost of equity of comparable-risk firms. The methodology rests on the basic premise that the required return on an investment depends on its risk, rather than on the identity of the investor, whether a parent company or individual

investor. The basic financial principle of risk and return states that the rate of return required by investors on any investment is dependent upon the risk of that investment and that investment alone. The risk of any investment is independent of the ownership of the capital financing the investment. In addition, it is a basic financial principle that it is the use of the funds invested which gives rise to the risk of the investment, not the source of the funds.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-043

REQUEST:

Refer to the Morin Testimony. Provide all Exhibits in Excel spreadsheet format with all formulas intact and unprotected and with all columns and rows accessible.

RESPONSE:

See STAFF-DR-02-043 Attachment.

PERSON RESPONSIBLE: Dr. Roger Morin, Ph.D.

STAFF-DR-02-043 ATTACHMENT IS BEING PROVIDED ON CD

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-044

REQUEST:

Refer to the Direct Testimony of Benjamin Walter Bohdan Passty, Ph.D. ("Passty Testimony"), page 3. Duke Kentucky states that the forecast methodology is essentially the same as that presented in past Integrated Resource Plans. Confirm that the forecast methodology used in this application is essentially the same as the forecast methodology utilized in Case No. 2014-00273.[1]

RESPONSE:

I can confirm that the forecast methodology is essentially the same, with the exception that a ten-year weather normalization period was used then. In the current forecast, a thirty-year weather normalization period is used.

PERSON RESPONSIBLE: Benjamin W. Passty

[1] Case No. 2014-00273, *2014 Integrated Resource Plan of Duke Energy Kentucky, Inc.*, (Ky.PSC Sept. 23, 2015).

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-045

REQUEST:

Refer to the Passty Testimony, page 4, and Attachment BWP-1.

a. What does Moody Analytics' forecast for the change in the population in Duke Kentucky service territory through the end of 2037?

b. What impact would the forecast have on the number of residential customers in Duke Kentucky's service territory?

RESPONSE:

a. Moody's analytics does not provide us with a forecast for population in the Duke Energy Kentucky service territory. For the state of Kentucky, they forecast an increase of 17.3% in the number of households.

b. In the most recent model used for the forecast, a 1% change in population predicts a 0.9% change in residential customers. Seasonal factors and adjustments offset some of these effects such that the final customer forecast shows growth of customers in this period of slightly more than 9%.

PERSON RESPONSIBLE: Benjamin W. Passty

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-046

REQUEST:

Refer to the Passty Testimony at page 8, lines 12-13. Explain why the load forecast does not reflect those projected energy-efficiency impacts.

RESPONSE:

The question misstates Dr. Passty's Testimony. Dr. Passty's testimony states on page 8, lines 12-13, "The load forecast provided here *does* reflect those projected energy efficiency impacts." (emphasis added).

PERSON RESPONSIBLE: Benjamin W. Passty

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-047

REQUEST:

Refer to the Passty Testimony, page 11.

a. Explain whether Duke Kentucky analyzed the impact of periods other than 30 years to calculate the Normal Weather in its electric forecast. If so, provide this impact. If not, explain why no other weather periods were considered.

b. Have any of Duke Kentucky's affiliates used periods other than 30 years for weather normalization? If so, provide a summary of those instances as well as the Orders approving them.

RESPONSE:

a. Duke Energy Kentucky does not analyze alternative normal periods as part of our semi-annual forecast process. Some more general analysis was done looking at all the Duke Energy service territories in aggregate. This analysis concluded that volatility in the forecast for normal weather would be reduced through switching to a longer period.

b. The Company is not aware of any affiliate that uses a different period at this time. Several Duke Energy Kentucky affiliates used a ten-year weather normalization for forecasts prior to 2015, including Duke Energy Kentucky. Case No. 2014-00273 is an example of a filing that used this normalization period.

PERSON RESPONSIBLE: Benjamin W. Passty

STAFF-DR-02-048

REQUEST:

Refer to the Passty Testimony, page 18.

a. Provide the monthly energy-efficiency impacts to Duke Kentucky's load forecast.

b. Provide the amount of the energy efficiency impact from the "roll-off" schedule that accounts for codes and standards that naturally reduce energy usage over time.

RESPONSE:

a. See STAFF-DR-02-048 ATTACHMENT included with this response. The attachment includes several categories of these impacts—sorted between residential, commercial/general service, and industrial customer classes—that are used to adjust the forecast. Columns C-E contain data on historical achievements already made by our existing programs. These are added back to our historical sales data before model estimation. Columns F-H repeat the most recent year of data in forecast years so that the forecast sales can be adjusted back down for these program activities. Columns I-K represent the MWH decrease caused by new program achievements.

b. See STAFF-DR-02-048 ATTACHMENT included with this response. Columns O-Q represent positive adjustments to the forecast that result from the "rolling off" of historical program achievements. Columns L-N represent the positive

adjustments to the forecast that result from the "rolling off" of new program achievements that are made during the forecast period.

PERSON RESPONSIBLE: Benjamin W. Passty

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2011	1	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	2	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	3	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	4	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	5	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	6	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	7	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	8	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	9	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	10	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	11	-	-	-	-	-	-	-	-	-	-	-	-	-
2011	12	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	1	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	2	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	3	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	4	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	5	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	6	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	7	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	8	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	9	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	10	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	11	-	-	-	-	-	-	-	-	-	-	-	-	-
2012	12	-	-	-	-	-	-	-	-	-	-	-	-	-
2013	1	-	(203)	(426)	-	-	-	-	-	-	-	-	-	-
2013	2	-	(189)	(396)	-	-	-	-	-	-	-	-	-	-
2013	3	-	(215)	(452)	-	-	-	-	-	-	-	-	-	-
2013	4	-	(216)	(455)	-	-	-	-	-	-	-	-	-	-
2013	5	-	(235)	(494)	-	-	-	-	-	-	-	-	-	-
2013	6	-	(236)	(495)	-	-	-	-	-	-	-	-	-	-
2013	7	-	(247)	(518)	-	-	-	-	-	-	-	-	-	-
2013	8	-	(254)	(533)	-	-	-	-	-	-	-	-	-	-
2013	9	-	(245)	(514)	-	-	-	-	-	-	-	-	-	-
2013	10	-	(249)	(522)	-	-	-	-	-	-	-	-	-	-
2013	11	-	(245)	(515)	-	-	-	-	-	-	-	-	-	-
2013	12	-	(258)	(541)	-	-	-	-	-	-	-	-	-	-
2014	1	(1,436)	(529)	(1,111)	(1,436)	-	-	-	-	-	-	-	-	-
2014	2	(1,284)	(492)	(1,034)	(1,284)	-	-	-	-	-	-	-	-	-
2014	3	(1,239)	(562)	(1,180)	(1,239)	-	-	-	-	-	-	-	-	-
2014	4	(943)	(564)	(1,185)	(943)	-	-	-	-	-	-	-	-	-
2014	5	(1,168)	(613)	(1,287)	(1,168)	-	-	-	-	-	-	-	-	-
2014	6	(1,438)	(614)	(1,290)	(1,438)	-	-	-	-	-	-	-	-	-
2014	7	(1,613)	(644)	(1,351)	(1,613)	-	-	-	-	-	-	-	-	-
2014	8	(1,541)	(662)	(1,390)	(1,541)	-	-	-	-	-	-	-	-	-
2014	9	(1,301)	(638)	(1,341)	(1,301)	-	-	-	-	-	-	-	-	-
2014	10	(968)	(649)	(1,362)	(968)	-	-	-	-	-	-	-	-	-
2014	11	(1,252)	(640)	(1,344)	(1,252)	-	-	-	-	-	-	-	-	-
2014	12	(1,607)	(672)	(1,412)	(1,607)	-	-	-	-	-	-	-	-	-
2015	1	(2,306)	(780)	(1,638)	(2,306)	-	-	-	-	-	-	-	-	-
2015	2	(2,061)	(726)	(1,524)	(2,061)	-	-	-	-	-	-	-	-	-
2015	3	(1,989)	(828)	(1,739)	(1,989)	-	-	-	-	-	-	-	-	-
2015	4	(1,515)	(832)	(1,747)	(1,515)	-	-	-	-	-	-	-	-	-
2015	5	(1,876)	(903)	(1,897)	(1,876)	-	-	-	-	-	-	-	-	-
2015	6	(2,310)	(905)	(1,902)	(2,310)	-	-	-	-	-	-	-	-	-
2015	7	(2,591)	(948)	(1,992)	(2,591)	-	-	-	-	-	-	-	-	-

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2015	8	(2,476)	(976)	(2,049)	(2,476)	-	-	-	-	-	-	-	-	-
2015	9	(2,089)	(941)	(1,976)	(2,089)	-	-	-	-	-	-	-	-	-
2015	10	(1,555)	(956)	(2,007)	(1,555)	-	-	-	-	-	-	-	-	-
2015	11	(2,011)	(943)	(1,981)	(2,011)	-	-	-	-	-	-	-	-	-
2015	12	(2,581)	(991)	(2,080)	(2,581)	-	-	-	-	-	-	-	-	-
2016	1	(3,209)	(1,243)	(2,610)	(3,209)	-	-	-	-	-	-	-	-	-
2016	2	(2,884)	(1,167)	(2,450)	(2,884)	-	-	-	-	-	-	-	-	-
2016	3	(2,820)	(1,343)	(2,821)	(2,820)	-	-	-	-	-	-	-	-	-
2016	4	(2,152)	(1,363)	(2,863)	(2,152)	-	-	-	-	-	-	-	-	-
2016	5	(2,693)	(1,484)	(3,116)	(2,693)	-	-	-	-	-	-	-	-	-
2016	6	(3,272)	(1,503)	(3,156)	(3,272)	-	-	-	-	-	-	-	-	-
2016	7	(3,668)	(1,587)	(3,333)	(3,668)	-	-	-	-	-	-	-	-	-
2016	8	(3,532)	(1,635)	(3,433)	(3,532)	-	-	-	-	-	-	-	-	-
2016	9	(3,022)	(1,590)	(3,339)	(3,022)	-	-	-	-	-	-	-	-	-
2016	10	(2,287)	(1,622)	(3,406)	(2,287)	-	-	-	-	-	-	-	-	-
2016	11	(2,949)	(1,610)	(3,381)	(2,949)	-	-	-	-	-	-	-	-	-
2016	12	(3,749)	(1,704)	(3,579)	(3,749)	-	-	-	-	-	-	-	-	-
2017	1	(3,832)	(1,560)	(3,276)	(3,832)	(1,560)	(3,276)	-	-	-	-	-	-	-
2017	2	(3,445)	(1,464)	(3,075)	(3,445)	(1,464)	(3,075)	-	-	-	-	-	-	-
2017	3	(3,369)	(1,686)	(3,540)	(3,369)	(1,686)	(3,540)	-	-	-	-	-	-	-
2017	4	(2,570)	(1,711)	(3,593)	(2,570)	(1,711)	(3,593)	-	-	-	-	-	-	-
2017	5	(3,217)	(1,862)	(3,911)	(3,217)	(1,862)	(3,911)	-	-	-	-	-	-	-
2017	6	(3,908)	(1,886)	(3,961)	(3,908)	(1,886)	(3,961)	-	-	-	-	-	-	-
2017	7	(4,382)	(1,992)	(4,183)	(4,382)	(1,992)	(4,183)	-	-	-	-	-	-	-
2017	8	(4,219)	(2,052)	(4,309)	(4,219)	(2,052)	(4,309)	-	-	-	-	-	-	-
2017	9	(3,609)	(1,996)	(4,191)	(3,609)	(1,996)	(4,191)	-	-	-	-	-	-	-
2017	10	(2,732)	(2,036)	(4,275)	(2,732)	(2,036)	(4,275)	-	-	-	-	-	-	-
2017	11	(3,522)	(2,021)	(4,243)	(3,522)	(2,021)	(4,243)	-	-	-	-	-	-	-
2017	12	(4,478)	(2,139)	(4,492)	(4,478)	(2,139)	(4,492)	-	-	-	-	-	-	-
2018	1	-	-	-	(3,832)	(1,560)	(3,276)	(84)	(34)	(72)	-	-	-	-
2018	2	-	-	-	(3,445)	(1,464)	(3,075)	(148)	(62)	(130)	-	-	-	-
2018	3	-	-	-	(3,369)	(1,686)	(3,540)	(212)	(103)	(216)	-	-	-	-
2018	4	-	-	-	(2,570)	(1,711)	(3,593)	(182)	(135)	(283)	-	-	-	-
2018	5	-	-	-	(3,217)	(1,862)	(3,911)	(325)	(181)	(380)	-	-	-	-
2018	6	-	-	-	(3,908)	(1,886)	(3,961)	(463)	(212)	(444)	-	-	-	-
2018	7	-	-	-	(4,382)	(1,992)	(4,183)	(596)	(254)	(534)	-	-	-	-
2018	8	-	-	-	(4,219)	(2,052)	(4,309)	(646)	(293)	(615)	-	-	-	-
2018	9	-	-	-	(3,609)	(1,996)	(4,191)	(619)	(309)	(649)	-	-	-	-
2018	10	-	-	-	(2,732)	(2,036)	(4,275)	(449)	(344)	(723)	-	-	-	-
2018	11	-	-	-	(3,522)	(2,021)	(4,243)	(731)	(364)	(765)	-	-	-	-
2018	12	-	-	-	(4,478)	(2,139)	(4,492)	(1,001)	(407)	(855)	-	-	-	-
2019	1	-	-	-	(3,307)	(1,262)	(2,649)	(1,051)	(451)	(947)	-	-	-	60
2019	2	-	-	-	(3,075)	(1,235)	(2,594)	(978)	(441)	(927)	-	-	-	56
2019	3	-	-	-	(3,095)	(1,475)	(3,097)	(984)	(527)	(1,107)	-	-	-	56
2019	4	-	-	-	(2,195)	(1,569)	(3,295)	(698)	(561)	(1,177)	-	-	-	40
2019	5	-	-	-	(3,116)	(1,787)	(3,753)	(990)	(639)	(1,341)	-	-	-	57
2019	6	-	-	-	(3,853)	(1,846)	(3,877)	(1,225)	(660)	(1,385)	-	-	-	70
2019	7	-	-	-	(4,421)	(2,030)	(4,262)	(1,405)	(725)	(1,523)	-	-	-	81
2019	8	-	-	-	(4,364)	(2,144)	(4,502)	(1,387)	(766)	(1,608)	-	-	-	80
2019	9	-	-	-	(3,866)	(2,133)	(4,479)	(1,229)	(762)	(1,600)	-	-	-	71
2019	10	-	-	-	(2,884)	(2,241)	(4,706)	(917)	(801)	(1,682)	-	-	-	53
2019	11	-	-	-	(3,989)	(2,251)	(4,727)	(1,268)	(804)	(1,689)	-	-	-	73
2019	12	-	-	-	(5,120)	(2,433)	(5,108)	(1,627)	(869)	(1,825)	-	-	-	93
2020	1	-	-	-	(3,585)	(1,465)	(3,076)	(1,675)	(915)	(1,921)	-	-	-	236
2020	2	-	-	-	(3,388)	(1,430)	(3,004)	(1,583)	(893)	(1,876)	-	-	-	223

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2020	3	-	-	-	(3,246)	(1,610)	(3,382)	(1,517)	(1,006)	(2,112)	-	-	-	214
2020	4	-	-	-	(2,446)	(1,660)	(3,486)	(1,143)	(1,037)	(2,177)	-	-	-	161
2020	5	-	-	-	(3,173)	(1,829)	(3,842)	(1,483)	(1,142)	(2,399)	-	-	-	209
2020	6	-	-	-	(3,861)	(1,875)	(3,937)	(1,804)	(1,171)	(2,458)	-	-	-	254
2020	7	-	-	-	(4,363)	(2,005)	(4,210)	(2,039)	(1,252)	(2,629)	-	-	-	287
2020	8	-	-	-	(4,253)	(2,072)	(4,350)	(1,987)	(1,294)	(2,717)	-	-	-	280
2020	9	-	-	-	(3,707)	(2,040)	(4,283)	(1,732)	(1,274)	(2,675)	-	-	-	244
2020	10	-	-	-	(2,837)	(2,099)	(4,409)	(1,326)	(1,311)	(2,753)	-	-	-	187
2020	11	-	-	-	(3,714)	(2,087)	(4,383)	(1,736)	(1,303)	(2,737)	-	-	-	244
2020	12	-	-	-	(4,712)	(2,233)	(4,690)	(2,202)	(1,395)	(2,929)	-	-	-	310
2021	1	-	-	-	(3,832)	(1,560)	(3,276)	(2,254)	(1,436)	(3,016)	-	-	-	595
2021	2	-	-	-	(3,445)	(1,464)	(3,075)	(2,026)	(1,348)	(2,831)	-	-	-	535
2021	3	-	-	-	(3,369)	(1,686)	(3,540)	(1,981)	(1,552)	(3,259)	-	-	-	523
2021	4	-	-	-	(2,570)	(1,711)	(3,593)	(1,512)	(1,575)	(3,308)	-	-	-	399
2021	5	-	-	-	(3,217)	(1,862)	(3,911)	(1,892)	(1,714)	(3,600)	-	-	-	499
2021	6	-	-	-	(3,908)	(1,886)	(3,961)	(2,298)	(1,736)	(3,646)	-	-	-	606
2021	7	-	-	-	(4,382)	(1,992)	(4,183)	(2,577)	(1,834)	(3,851)	-	-	-	680
2021	8	-	-	-	(4,219)	(2,052)	(4,309)	(2,481)	(1,889)	(3,966)	-	-	-	655
2021	9	-	-	-	(3,609)	(1,996)	(4,191)	(2,123)	(1,837)	(3,858)	-	-	-	560
2021	10	-	-	-	(2,732)	(2,036)	(4,275)	(1,607)	(1,874)	(3,935)	-	-	-	424
2021	11	-	-	-	(3,522)	(2,021)	(4,243)	(2,071)	(1,860)	(3,906)	-	-	-	547
2021	12	-	-	-	(4,478)	(2,139)	(4,492)	(2,634)	(1,969)	(4,135)	-	-	-	695
2022	1	-	-	-	(3,936)	(1,629)	(3,421)	(2,679)	(2,007)	(4,215)	-	-	-	1,160
2022	2	-	-	-	(3,518)	(1,515)	(3,182)	(2,394)	(1,867)	(3,920)	-	-	-	1,036
2022	3	-	-	-	(3,395)	(1,730)	(3,632)	(2,311)	(2,131)	(4,475)	-	-	-	1,000
2022	4	-	-	-	(2,585)	(1,737)	(3,648)	(1,759)	(2,140)	(4,495)	-	-	-	762
2022	5	-	-	-	(3,202)	(1,887)	(3,962)	(2,179)	(2,324)	(4,881)	-	-	-	943
2022	6	-	-	-	(3,942)	(1,891)	(3,971)	(2,683)	(2,330)	(4,892)	-	-	-	1,161
2022	7	-	-	-	(4,422)	(1,981)	(4,159)	(3,009)	(2,440)	(5,124)	-	-	-	1,303
2022	8	-	-	-	(4,225)	(2,037)	(4,278)	(2,875)	(2,510)	(5,271)	-	-	-	1,245
2022	9	-	-	-	(3,565)	(1,965)	(4,126)	(2,426)	(2,421)	(5,083)	-	-	-	1,050
2022	10	-	-	-	(2,653)	(1,996)	(4,192)	(1,806)	(2,459)	(5,164)	-	-	-	782
2022	11	-	-	-	(3,433)	(1,970)	(4,136)	(2,336)	(2,427)	(5,096)	-	-	-	1,011
2022	12	-	-	-	(4,406)	(2,069)	(4,344)	(2,998)	(2,549)	(5,353)	-	-	-	1,298
2023	1	-	-	-	(4,186)	(1,852)	(3,890)	(3,203)	(2,866)	(6,018)	-	-	-	1,950
2023	2	-	-	-	(3,698)	(1,677)	(3,522)	(2,830)	(2,595)	(5,449)	-	-	-	1,723
2023	3	-	-	-	(3,506)	(1,870)	(3,927)	(2,683)	(2,893)	(6,076)	-	-	-	1,633
2023	4	-	-	-	(2,639)	(1,832)	(3,846)	(2,019)	(2,834)	(5,951)	-	-	-	1,229
2023	5	-	-	-	(3,230)	(1,954)	(4,104)	(2,471)	(3,024)	(6,350)	-	-	-	1,504
2023	6	-	-	-	(3,973)	(1,912)	(4,015)	(3,041)	(2,958)	(6,211)	-	-	-	1,851
2023	7	-	-	-	(4,416)	(1,961)	(4,118)	(3,379)	(3,034)	(6,371)	-	-	-	2,057
2023	8	-	-	-	(4,168)	(1,975)	(4,147)	(3,190)	(3,055)	(6,416)	-	-	-	1,941
2023	9	-	-	-	(3,475)	(1,861)	(3,909)	(2,659)	(2,880)	(6,047)	-	-	-	1,618
2023	10	-	-	-	(2,550)	(1,864)	(3,914)	(1,951)	(2,884)	(6,056)	-	-	-	1,188
2023	11	-	-	-	(3,276)	(1,799)	(3,777)	(2,507)	(2,783)	(5,843)	-	-	-	1,526
2023	12	-	-	-	(4,167)	(1,848)	(3,881)	(3,189)	(2,859)	(6,004)	-	-	-	1,941
2024	1	-	-	-	(4,170)	(1,852)	(3,889)	(3,544)	(3,448)	(7,242)	-	-	-	2,666
2024	2	-	-	-	(3,818)	(1,733)	(3,640)	(3,245)	(3,228)	(6,778)	-	-	-	2,441
2024	3	-	-	-	(3,501)	(1,855)	(3,895)	(2,976)	(3,454)	(7,253)	-	-	-	2,239
2024	4	-	-	-	(2,626)	(1,836)	(3,856)	(2,232)	(3,419)	(7,180)	-	-	-	1,679
2024	5	-	-	-	(3,220)	(1,949)	(4,092)	(2,737)	(3,629)	(7,620)	-	-	-	2,059
2024	6	-	-	-	(3,967)	(1,896)	(3,982)	(3,372)	(3,531)	(7,415)	-	-	-	2,536
2024	7	-	-	-	(4,398)	(1,965)	(4,125)	(3,738)	(3,658)	(7,682)	-	-	-	2,812
2024	8	-	-	-	(4,157)	(1,964)	(4,125)	(3,534)	(3,657)	(7,681)	-	-	-	2,658
2024	9	-	-	-	(3,464)	(1,856)	(3,897)	(2,944)	(3,456)	(7,257)	-	-	-	2,215

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2024	10	-	-	-	(2,539)	(1,863)	(3,913)	(2,158)	(3,470)	(7,287)	-	-	-	1,624
2024	11	-	-	-	(3,268)	(1,788)	(3,756)	(2,778)	(3,330)	(6,994)	-	-	-	2,090
2024	12	-	-	-	(4,153)	(1,848)	(3,880)	(3,530)	(3,441)	(7,225)	-	-	-	2,656
2025	1	-	-	-	(4,182)	(1,857)	(3,900)	(3,909)	(4,043)	(8,490)	27	0	0	3,312
2025	2	-	-	-	(3,699)	(1,677)	(3,521)	(3,457)	(3,651)	(7,667)	24	0	0	2,929
2025	3	-	-	-	(3,512)	(1,860)	(3,906)	(3,283)	(4,049)	(8,503)	22	0	0	2,781
2025	4	-	-	-	(2,634)	(1,841)	(3,867)	(2,462)	(4,009)	(8,418)	17	0	0	2,085
2025	5	-	-	-	(3,233)	(1,949)	(4,093)	(3,022)	(4,244)	(8,912)	21	0	0	2,560
2025	6	-	-	-	(3,976)	(1,906)	(4,003)	(3,716)	(4,151)	(8,716)	25	0	0	3,148
2025	7	-	-	-	(4,412)	(1,970)	(4,137)	(4,123)	(4,289)	(9,007)	28	0	0	3,493
2025	8	-	-	-	(4,171)	(1,964)	(4,125)	(3,899)	(4,277)	(8,982)	27	0	0	3,303
2025	9	-	-	-	(3,472)	(1,866)	(3,918)	(3,245)	(4,062)	(8,531)	22	0	0	2,749
2025	10	-	-	-	(2,547)	(1,868)	(3,924)	(2,381)	(4,068)	(8,543)	16	0	0	2,017
2025	11	-	-	-	(3,281)	(1,788)	(3,755)	(3,066)	(3,894)	(8,177)	21	0	0	2,598
2025	12	-	-	-	(4,165)	(1,858)	(3,901)	(3,893)	(4,045)	(8,494)	27	0	0	3,298
2026	1	-	-	-	(4,186)	(1,852)	(3,889)	(4,267)	(4,616)	(9,693)	91	2	5	3,777
2026	2	-	-	-	(3,698)	(1,677)	(3,521)	(3,770)	(4,179)	(8,776)	80	2	5	3,338
2026	3	-	-	-	(3,509)	(1,865)	(3,916)	(3,577)	(4,648)	(9,760)	76	2	5	3,166
2026	4	-	-	-	(2,634)	(1,841)	(3,866)	(2,685)	(4,589)	(9,636)	57	2	5	2,377
2026	5	-	-	-	(3,236)	(1,944)	(4,083)	(3,299)	(4,846)	(10,176)	70	3	5	2,920
2026	6	-	-	-	(3,973)	(1,911)	(4,014)	(4,050)	(4,763)	(10,003)	86	3	5	3,586
2026	7	-	-	-	(4,411)	(1,970)	(4,137)	(4,497)	(4,909)	(10,310)	95	3	6	3,981
2026	8	-	-	-	(4,171)	(1,964)	(4,125)	(4,252)	(4,896)	(10,282)	90	3	6	3,764
2026	9	-	-	-	(3,472)	(1,866)	(3,918)	(3,539)	(4,650)	(9,766)	75	2	5	3,133
2026	10	-	-	-	(2,550)	(1,864)	(3,913)	(2,599)	(4,644)	(9,753)	55	2	5	2,301
2026	11	-	-	-	(3,278)	(1,793)	(3,766)	(3,342)	(4,469)	(9,386)	71	2	5	2,958
2026	12	-	-	-	(4,165)	(1,858)	(3,901)	(4,245)	(4,630)	(9,723)	90	2	5	3,758
2027	1	-	-	-	(4,190)	(1,847)	(3,879)	(4,626)	(5,185)	(10,890)	167	8	16	4,035
2027	2	-	-	-	(3,698)	(1,677)	(3,521)	(4,083)	(4,707)	(9,885)	148	7	15	3,562
2027	3	-	-	-	(3,506)	(1,870)	(3,926)	(3,870)	(5,249)	(11,023)	140	8	16	3,376
2027	4	-	-	-	(2,633)	(1,841)	(3,866)	(2,908)	(5,169)	(10,854)	105	8	16	2,536
2027	5	-	-	-	(3,236)	(1,944)	(4,083)	(3,572)	(5,458)	(11,462)	129	8	17	3,116
2027	6	-	-	-	(3,973)	(1,911)	(4,014)	(4,387)	(5,366)	(11,268)	159	8	17	3,826
2027	7	-	-	-	(4,413)	(1,965)	(4,127)	(4,873)	(5,517)	(11,585)	176	8	17	4,250
2027	8	-	-	-	(4,170)	(1,969)	(4,136)	(4,604)	(5,529)	(11,610)	167	8	17	4,015
2027	9	-	-	-	(3,471)	(1,866)	(3,918)	(3,833)	(5,238)	(11,000)	139	8	16	3,343
2027	10	-	-	-	(2,553)	(1,859)	(3,903)	(2,818)	(5,218)	(10,957)	102	8	16	2,458
2027	11	-	-	-	(3,276)	(1,798)	(3,776)	(3,617)	(5,048)	(10,601)	131	7	16	3,155
2027	12	-	-	-	(4,164)	(1,858)	(3,901)	(4,598)	(5,215)	(10,952)	166	8	16	4,010
2028	1	-	-	-	(4,177)	(1,843)	(3,870)	(4,965)	(5,754)	(12,084)	245	79	166	4,143
2028	2	-	-	-	(3,817)	(1,734)	(3,642)	(4,538)	(5,415)	(11,371)	224	74	156	3,786
2028	3	-	-	-	(3,495)	(1,865)	(3,917)	(4,155)	(5,825)	(12,232)	205	80	168	3,466
2028	4	-	-	-	(2,630)	(1,827)	(3,837)	(3,127)	(5,705)	(11,980)	154	78	164	2,609
2028	5	-	-	-	(3,220)	(1,949)	(4,094)	(3,827)	(6,087)	(12,783)	189	83	175	3,193
2028	6	-	-	-	(3,961)	(1,907)	(4,004)	(4,709)	(5,954)	(12,503)	232	82	171	3,929
2028	7	-	-	-	(4,402)	(1,956)	(4,107)	(5,233)	(6,107)	(12,825)	258	84	176	4,366
2028	8	-	-	-	(4,155)	(1,970)	(4,137)	(4,940)	(6,151)	(12,916)	244	84	177	4,121
2028	9	-	-	-	(3,464)	(1,857)	(3,899)	(4,118)	(5,797)	(12,174)	203	79	167	3,436
2028	10	-	-	-	(2,542)	(1,859)	(3,904)	(3,022)	(5,805)	(12,191)	149	80	167	2,521
2028	11	-	-	-	(3,266)	(1,794)	(3,768)	(3,883)	(5,602)	(11,764)	192	77	161	3,239
2028	12	-	-	-	(4,154)	(1,843)	(3,871)	(4,938)	(5,756)	(12,088)	244	79	166	4,120
2029	1	-	-	-	(4,182)	(1,857)	(3,899)	(5,326)	(6,383)	(13,404)	325	198	416	4,182
2029	2	-	-	-	(3,699)	(1,677)	(3,521)	(4,710)	(5,764)	(12,104)	287	179	376	3,699
2029	3	-	-	-	(3,509)	(1,865)	(3,916)	(4,469)	(6,410)	(13,461)	273	199	418	3,509
2029	4	-	-	-	(2,636)	(1,836)	(3,856)	(3,357)	(6,312)	(13,255)	205	196	412	2,636

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2029	5	-	-	-	(3,230)	(1,954)	(4,103)	(4,113)	(6,717)	(14,105)	251	209	438	3,230
2029	6	-	-	-	(3,976)	(1,906)	(4,003)	(5,064)	(6,553)	(13,761)	309	203	427	3,976
2029	7	-	-	-	(4,414)	(1,965)	(4,127)	(5,621)	(6,755)	(14,186)	343	210	440	4,414
2029	8	-	-	-	(4,168)	(1,974)	(4,146)	(5,309)	(6,787)	(14,252)	324	211	442	4,168
2029	9	-	-	-	(3,478)	(1,856)	(3,898)	(4,429)	(6,380)	(13,398)	270	198	416	3,478
2029	10	-	-	-	(2,547)	(1,868)	(3,924)	(3,244)	(6,423)	(13,488)	198	199	419	2,547
2029	11	-	-	-	(3,276)	(1,798)	(3,776)	(4,172)	(6,181)	(12,981)	255	192	403	3,276
2029	12	-	-	-	(4,167)	(1,848)	(3,880)	(5,307)	(6,352)	(13,338)	324	197	414	4,167
2030	1	-	-	-	(4,182)	(1,857)	(3,900)	(5,680)	(6,968)	(14,633)	405	357	750	4,182
2030	2	-	-	-	(3,699)	(1,677)	(3,521)	(5,024)	(6,292)	(13,214)	359	322	677	3,699
2030	3	-	-	-	(3,512)	(1,860)	(3,906)	(4,770)	(6,979)	(14,656)	340	358	751	3,512
2030	4	-	-	-	(2,634)	(1,841)	(3,867)	(3,577)	(6,909)	(14,509)	255	354	743	2,634
2030	5	-	-	-	(3,230)	(1,954)	(4,103)	(4,387)	(7,333)	(15,398)	313	376	789	3,230
2030	6	-	-	-	(3,979)	(1,901)	(3,993)	(5,404)	(7,135)	(14,984)	386	366	768	3,979
2030	7	-	-	-	(4,412)	(1,970)	(4,137)	(5,992)	(7,392)	(15,523)	428	379	795	4,412
2030	8	-	-	-	(4,170)	(1,969)	(4,136)	(5,664)	(7,390)	(15,520)	404	379	795	4,170
2030	9	-	-	-	(3,475)	(1,861)	(3,908)	(4,719)	(6,983)	(14,665)	337	358	751	3,475
2030	10	-	-	-	(2,547)	(1,868)	(3,924)	(3,460)	(7,011)	(14,724)	247	359	754	2,547
2030	11	-	-	-	(3,278)	(1,793)	(3,766)	(4,453)	(6,729)	(14,132)	318	345	724	3,278
2030	12	-	-	-	(4,166)	(1,853)	(3,891)	(5,658)	(6,952)	(14,600)	404	356	748	4,166
2031	1	-	-	-	(4,182)	(1,857)	(3,900)	(6,035)	(7,553)	(15,862)	822	584	1,227	4,182
2031	2	-	-	-	(3,699)	(1,677)	(3,521)	(5,337)	(6,821)	(14,323)	727	528	1,108	3,699
2031	3	-	-	-	(3,512)	(1,860)	(3,906)	(5,068)	(7,565)	(15,887)	690	585	1,229	3,512
2031	4	-	-	-	(2,634)	(1,841)	(3,867)	(3,800)	(7,489)	(15,727)	517	579	1,217	2,634
2031	5	-	-	-	(3,233)	(1,949)	(4,093)	(4,665)	(7,928)	(16,649)	635	613	1,288	3,233
2031	6	-	-	-	(3,976)	(1,906)	(4,003)	(5,738)	(7,754)	(16,284)	781	600	1,260	3,976
2031	7	-	-	-	(4,412)	(1,970)	(4,137)	(6,366)	(8,013)	(16,827)	867	620	1,302	4,412
2031	8	-	-	-	(4,171)	(1,964)	(4,125)	(6,019)	(7,991)	(16,780)	819	618	1,298	4,171
2031	9	-	-	-	(3,472)	(1,866)	(3,918)	(5,010)	(7,590)	(15,938)	682	587	1,233	3,472
2031	10	-	-	-	(2,547)	(1,868)	(3,924)	(3,675)	(7,600)	(15,960)	500	588	1,235	2,547
2031	11	-	-	-	(3,281)	(1,788)	(3,755)	(4,734)	(7,274)	(15,276)	644	563	1,182	3,281
2031	12	-	-	-	(4,165)	(1,858)	(3,901)	(6,010)	(7,556)	(15,868)	818	585	1,228	4,165
2032	1	-	-	-	(4,173)	(1,847)	(3,879)	(6,375)	(8,095)	(16,999)	1,497	963	2,022	4,173
2032	2	-	-	-	(3,822)	(1,728)	(3,630)	(5,838)	(7,575)	(15,908)	1,371	901	1,892	3,822
2032	3	-	-	-	(3,495)	(1,865)	(3,916)	(5,339)	(8,172)	(17,161)	1,254	972	2,041	3,495
2032	4	-	-	-	(2,626)	(1,836)	(3,856)	(4,011)	(8,047)	(16,899)	942	957	2,010	2,626
2032	5	-	-	-	(3,226)	(1,939)	(4,072)	(4,928)	(8,497)	(17,845)	1,157	1,011	2,123	3,226
2032	6	-	-	-	(3,961)	(1,906)	(4,003)	(6,051)	(8,354)	(17,542)	1,421	994	2,087	3,961
2032	7	-	-	-	(4,400)	(1,960)	(4,116)	(6,722)	(8,589)	(18,037)	1,578	1,022	2,145	4,400
2032	8	-	-	-	(4,157)	(1,964)	(4,124)	(6,350)	(8,608)	(18,076)	1,491	1,024	2,150	4,157
2032	9	-	-	-	(3,461)	(1,861)	(3,908)	(5,287)	(8,155)	(17,126)	1,242	970	2,037	3,461
2032	10	-	-	-	(2,545)	(1,853)	(3,892)	(3,888)	(8,123)	(17,059)	913	966	2,029	2,545
2032	11	-	-	-	(3,266)	(1,793)	(3,766)	(4,989)	(7,859)	(16,505)	1,172	935	1,963	3,266
2032	12	-	-	-	(4,152)	(1,853)	(3,890)	(6,343)	(8,119)	(17,050)	1,489	966	2,028	4,152
2033	1	-	-	-	(4,190)	(1,848)	(3,880)	(6,755)	(8,679)	(18,226)	2,133	1,489	3,127	4,190
2033	2	-	-	-	(3,698)	(1,677)	(3,522)	(5,963)	(7,879)	(16,545)	1,883	1,352	2,839	3,698
2033	3	-	-	-	(3,505)	(1,870)	(3,927)	(5,652)	(8,785)	(18,449)	1,785	1,507	3,165	3,505
2033	4	-	-	-	(2,636)	(1,837)	(3,857)	(4,250)	(8,628)	(18,118)	1,342	1,480	3,109	2,636
2033	5	-	-	-	(3,232)	(1,949)	(4,094)	(5,212)	(9,158)	(19,232)	1,646	1,571	3,300	3,232
2033	6	-	-	-	(3,973)	(1,912)	(4,015)	(6,406)	(8,980)	(18,859)	2,023	1,541	3,236	3,973
2033	7	-	-	-	(4,415)	(1,961)	(4,118)	(7,119)	(9,211)	(19,344)	2,248	1,580	3,319	4,415
2033	8	-	-	-	(4,168)	(1,975)	(4,147)	(6,720)	(9,277)	(19,482)	2,122	1,592	3,343	4,168
2033	9	-	-	-	(3,471)	(1,866)	(3,919)	(5,597)	(8,767)	(18,411)	1,767	1,504	3,159	3,471
2033	10	-	-	-	(2,553)	(1,859)	(3,904)	(4,116)	(8,733)	(18,339)	1,299	1,498	3,146	2,553
2033	11	-	-	-	(3,276)	(1,799)	(3,777)	(5,282)	(8,449)	(17,743)	1,668	1,450	3,044	3,276

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2033	12	-	-	-	(4,166)	(1,853)	(3,891)	(6,716)	(8,705)	(18,281)	2,121	1,494	3,137	4,166
2034	1	-	-	-	(4,186)	(1,852)	(3,890)	(7,104)	(9,286)	(19,500)	2,639	2,059	4,324	4,186
2034	2	-	-	-	(3,698)	(1,677)	(3,522)	(6,277)	(8,407)	(17,655)	2,332	1,864	3,915	3,698
2034	3	-	-	-	(3,506)	(1,870)	(3,927)	(5,949)	(9,374)	(19,686)	2,210	2,079	4,365	3,506
2034	4	-	-	-	(2,639)	(1,832)	(3,846)	(4,478)	(9,182)	(19,282)	1,664	2,036	4,276	2,639
2034	5	-	-	-	(3,230)	(1,954)	(4,104)	(5,481)	(9,797)	(20,574)	2,036	2,172	4,562	3,230
2034	6	-	-	-	(3,973)	(1,912)	(4,015)	(6,743)	(9,583)	(20,124)	2,505	2,125	4,462	3,973
2034	7	-	-	-	(4,416)	(1,961)	(4,118)	(7,494)	(9,829)	(20,641)	2,784	2,180	4,577	4,416
2034	8	-	-	-	(4,168)	(1,975)	(4,147)	(7,074)	(9,899)	(20,788)	2,628	2,195	4,610	4,168
2034	9	-	-	-	(3,475)	(1,861)	(3,909)	(5,897)	(9,330)	(19,594)	2,191	2,069	4,345	3,475
2034	10	-	-	-	(2,550)	(1,864)	(3,914)	(4,327)	(9,343)	(19,621)	1,608	2,072	4,351	2,550
2034	11	-	-	-	(3,276)	(1,799)	(3,777)	(5,560)	(9,016)	(18,933)	2,066	1,999	4,198	3,276
2034	12	-	-	-	(4,167)	(1,848)	(3,881)	(7,072)	(9,264)	(19,455)	2,627	2,054	4,314	4,167
2035	1	-	-	-	(4,182)	(1,857)	(3,899)	(7,452)	(9,893)	(20,776)	3,024	2,644	5,551	4,182
2035	2	-	-	-	(3,699)	(1,677)	(3,521)	(6,590)	(8,934)	(18,761)	2,675	2,387	5,013	3,699
2035	3	-	-	-	(3,509)	(1,865)	(3,916)	(6,252)	(9,935)	(20,864)	2,538	2,655	5,575	3,509
2035	4	-	-	-	(2,636)	(1,836)	(3,856)	(4,697)	(9,783)	(20,545)	1,906	2,614	5,490	2,636
2035	5	-	-	-	(3,230)	(1,954)	(4,103)	(5,755)	(10,411)	(21,862)	2,336	2,782	5,842	3,230
2035	6	-	-	-	(3,976)	(1,906)	(4,003)	(7,085)	(10,157)	(21,329)	2,876	2,714	5,699	3,976
2035	7	-	-	-	(4,414)	(1,965)	(4,127)	(7,865)	(10,470)	(21,987)	3,192	2,798	5,875	4,414
2035	8	-	-	-	(4,168)	(1,974)	(4,146)	(7,427)	(10,519)	(22,090)	3,014	2,811	5,903	4,168
2035	9	-	-	-	(3,478)	(1,856)	(3,898)	(6,196)	(9,889)	(20,766)	2,515	2,642	5,549	3,478
2035	10	-	-	-	(2,547)	(1,868)	(3,924)	(4,539)	(9,955)	(20,905)	1,842	2,660	5,586	2,547
2035	11	-	-	-	(3,276)	(1,798)	(3,776)	(5,838)	(9,581)	(20,119)	2,369	2,560	5,376	3,276
2035	12	-	-	-	(4,167)	(1,848)	(3,880)	(7,425)	(9,844)	(20,673)	3,014	2,630	5,524	4,167
2036	1	-	-	-	(4,170)	(1,852)	(3,889)	(7,783)	(10,450)	(21,945)	3,369	3,218	6,758	4,170
2036	2	-	-	-	(3,818)	(1,733)	(3,640)	(7,126)	(9,781)	(20,541)	3,085	3,012	6,326	3,818
2036	3	-	-	-	(3,501)	(1,855)	(3,895)	(6,535)	(10,466)	(21,979)	2,829	3,223	6,768	3,501
2036	4	-	-	-	(2,626)	(1,836)	(3,856)	(4,901)	(10,361)	(21,759)	2,121	3,191	6,701	2,626
2036	5	-	-	-	(3,223)	(1,944)	(4,082)	(6,016)	(10,969)	(23,034)	2,604	3,378	7,093	3,223
2036	6	-	-	-	(3,964)	(1,901)	(3,992)	(7,399)	(10,728)	(22,529)	3,203	3,304	6,938	3,964
2036	7	-	-	-	(4,398)	(1,965)	(4,125)	(8,210)	(11,086)	(23,280)	3,554	3,414	7,169	4,398
2036	8	-	-	-	(4,159)	(1,959)	(4,114)	(7,763)	(11,055)	(23,216)	3,360	3,404	7,149	4,159
2036	9	-	-	-	(3,461)	(1,861)	(3,908)	(6,461)	(10,500)	(22,050)	2,796	3,234	6,790	3,461
2036	10	-	-	-	(2,539)	(1,863)	(3,913)	(4,740)	(10,515)	(22,081)	2,052	3,238	6,800	2,539
2036	11	-	-	-	(3,271)	(1,783)	(3,745)	(6,105)	(10,064)	(21,134)	2,642	3,099	6,508	3,271
2036	12	-	-	-	(4,152)	(1,853)	(3,890)	(7,750)	(10,454)	(21,954)	3,355	3,219	6,761	4,152
2037	1	-	-	-	(4,186)	(1,852)	(3,889)	(8,168)	(11,034)	(23,172)	3,736	3,802	7,984	4,186
2037	2	-	-	-	(3,698)	(1,677)	(3,521)	(7,217)	(9,990)	(20,980)	3,301	3,442	7,229	3,698
2037	3	-	-	-	(3,509)	(1,865)	(3,916)	(6,846)	(11,110)	(23,332)	3,132	3,828	8,039	3,509
2037	4	-	-	-	(2,634)	(1,841)	(3,866)	(5,139)	(10,970)	(23,036)	2,351	3,780	7,937	2,634
2037	5	-	-	-	(3,236)	(1,944)	(4,083)	(6,314)	(11,583)	(24,325)	2,888	3,991	8,381	3,236
2037	6	-	-	-	(3,973)	(1,911)	(4,014)	(7,753)	(11,387)	(23,913)	3,547	3,923	8,239	3,973
2037	7	-	-	-	(4,411)	(1,970)	(4,137)	(8,608)	(11,736)	(24,646)	3,938	4,044	8,492	4,411
2037	8	-	-	-	(4,171)	(1,964)	(4,125)	(8,139)	(11,704)	(24,579)	3,723	4,033	8,469	4,171
2037	9	-	-	-	(3,472)	(1,866)	(3,918)	(6,774)	(11,117)	(23,345)	3,099	3,830	8,044	3,472
2037	10	-	-	-	(2,550)	(1,864)	(3,913)	(4,975)	(11,103)	(23,316)	2,276	3,825	8,033	2,550
2037	11	-	-	-	(3,278)	(1,793)	(3,766)	(6,397)	(10,684)	(22,437)	2,926	3,681	7,731	3,278
2037	12	-	-	-	(4,165)	(1,858)	(3,901)	(8,126)	(11,068)	(23,243)	3,717	3,813	8,008	4,165
2038	1	-	-	-	(4,190)	(1,847)	(3,879)	(8,530)	(11,587)	(24,333)	4,095	4,374	9,185	4,190
2038	2	-	-	-	(3,698)	(1,677)	(3,521)	(7,530)	(10,519)	(22,089)	3,615	3,970	8,338	3,698
2038	3	-	-	-	(3,506)	(1,870)	(3,926)	(7,137)	(11,729)	(24,630)	3,426	4,427	9,297	3,506
2038	4	-	-	-	(2,633)	(1,841)	(3,866)	(5,362)	(11,550)	(24,254)	2,574	4,360	9,155	2,633
2038	5	-	-	-	(3,236)	(1,944)	(4,083)	(6,588)	(12,196)	(25,611)	3,162	4,604	9,667	3,236
2038	6	-	-	-	(3,973)	(1,911)	(4,014)	(8,089)	(11,989)	(25,178)	3,883	4,526	9,504	3,973

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2038	7	-	-	-	(4,413)	(1,965)	(4,127)	(8,985)	(12,327)	(25,887)	4,313	4,653	9,772	4,413
2038	8	-	-	-	(4,170)	(1,969)	(4,136)	(8,489)	(12,354)	(25,944)	4,075	4,663	9,793	4,170
2038	9	-	-	-	(3,471)	(1,866)	(3,918)	(7,068)	(11,704)	(24,579)	3,393	4,418	9,278	3,471
2038	10	-	-	-	(2,553)	(1,859)	(3,903)	(5,197)	(11,659)	(24,483)	2,495	4,401	9,242	2,553
2038	11	-	-	-	(3,276)	(1,798)	(3,776)	(6,670)	(11,280)	(23,688)	3,202	4,258	8,941	3,276
2038	12	-	-	-	(4,164)	(1,858)	(3,901)	(8,478)	(11,653)	(24,471)	4,070	4,399	9,237	4,164
2039	1	-	-	-	(4,190)	(1,848)	(3,880)	(8,884)	(12,172)	(25,560)	4,450	4,957	10,409	4,190
2039	2	-	-	-	(3,698)	(1,677)	(3,522)	(7,843)	(11,049)	(23,203)	3,928	4,500	9,449	3,698
2039	3	-	-	-	(3,505)	(1,870)	(3,927)	(7,434)	(12,320)	(25,873)	3,723	5,017	10,536	3,505
2039	4	-	-	-	(2,636)	(1,837)	(3,857)	(5,590)	(12,100)	(25,409)	2,799	4,927	10,348	2,636
2039	5	-	-	-	(3,232)	(1,949)	(4,094)	(6,855)	(12,843)	(26,971)	3,433	5,230	10,984	3,232
2039	6	-	-	-	(3,973)	(1,912)	(4,015)	(8,425)	(12,594)	(26,448)	4,220	5,129	10,771	3,973
2039	7	-	-	-	(4,415)	(1,961)	(4,118)	(9,364)	(12,918)	(27,128)	4,689	5,261	11,048	4,415
2039	8	-	-	-	(4,168)	(1,975)	(4,147)	(8,838)	(13,010)	(27,321)	4,426	5,298	11,126	4,168
2039	9	-	-	-	(3,471)	(1,866)	(3,919)	(7,362)	(12,295)	(25,819)	3,687	5,007	10,515	3,471
2039	10	-	-	-	(2,553)	(1,859)	(3,904)	(5,413)	(12,247)	(25,718)	2,711	4,987	10,473	2,553
2039	11	-	-	-	(3,276)	(1,799)	(3,777)	(6,947)	(11,849)	(24,883)	3,479	4,825	10,133	3,276
2039	12	-	-	-	(4,166)	(1,853)	(3,891)	(8,834)	(12,208)	(25,637)	4,424	4,972	10,441	4,166
2040	1	-	-	-	(4,173)	(1,847)	(3,879)	(9,203)	(12,753)	(26,781)	4,786	5,538	11,631	4,173
2040	2	-	-	-	(3,818)	(1,734)	(3,641)	(8,419)	(11,968)	(25,133)	4,378	5,198	10,915	3,818
2040	3	-	-	-	(3,498)	(1,860)	(3,906)	(7,715)	(12,840)	(26,965)	4,012	5,577	11,711	3,498
2040	4	-	-	-	(2,628)	(1,832)	(3,846)	(5,796)	(12,644)	(26,552)	3,014	5,491	11,531	2,628
2040	5	-	-	-	(3,220)	(1,949)	(4,093)	(7,101)	(13,455)	(28,255)	3,692	5,843	12,271	3,220
2040	6	-	-	-	(3,964)	(1,902)	(3,993)	(8,742)	(13,127)	(27,566)	4,546	5,701	11,972	3,964
2040	7	-	-	-	(4,400)	(1,960)	(4,116)	(9,704)	(13,532)	(28,416)	5,046	5,877	12,341	4,400
2040	8	-	-	-	(4,155)	(1,969)	(4,136)	(9,164)	(13,595)	(28,550)	4,765	5,904	12,399	4,155
2040	9	-	-	-	(3,467)	(1,851)	(3,888)	(7,646)	(12,780)	(26,838)	3,976	5,550	11,656	3,467
2040	10	-	-	-	(2,539)	(1,864)	(3,914)	(5,600)	(12,866)	(27,018)	2,912	5,588	11,734	2,539
2040	11	-	-	-	(3,266)	(1,794)	(3,767)	(7,203)	(12,382)	(26,002)	3,745	5,377	11,293	3,266
2040	12	-	-	-	(4,154)	(1,843)	(3,871)	(9,162)	(12,723)	(26,719)	4,764	5,526	11,604	4,154
2041	1	-	-	-	(4,831)	(1,881)	(3,949)	(9,577)	(13,404)	(28,148)	5,150	6,152	12,919	4,831
2041	2	-	-	-	(4,450)	(1,767)	(3,711)	(8,470)	(12,104)	(25,418)	4,555	5,555	11,666	4,450
2041	3	-	-	-	(3,723)	(1,869)	(3,926)	(8,043)	(13,425)	(28,192)	4,325	6,162	12,940	3,723
2041	4	-	-	-	(954)	(1,794)	(3,768)	(6,031)	(13,290)	(27,909)	3,243	6,100	12,810	954
2041	5	-	-	-	(3,325)	(1,907)	(4,005)	(7,396)	(14,104)	(29,619)	3,977	6,474	13,595	3,325
2041	6	-	-	-	(3,989)	(1,876)	(3,939)	(9,112)	(13,725)	(28,822)	4,900	6,299	13,229	3,989
2041	7	-	-	-	(4,811)	(1,948)	(4,090)	(10,103)	(14,219)	(29,860)	5,433	6,526	13,705	4,811
2041	8	-	-	-	(4,558)	(1,962)	(4,120)	(9,549)	(14,216)	(29,853)	5,135	6,525	13,702	4,558
2041	9	-	-	-	(3,655)	(1,855)	(3,896)	(7,957)	(13,433)	(28,209)	4,279	6,165	12,947	3,655
2041	10	-	-	-	(956)	(1,860)	(3,907)	(5,833)	(13,487)	(28,323)	3,137	6,190	13,000	956
2041	11	-	-	-	(3,541)	(1,822)	(3,826)	(7,508)	(12,944)	(27,183)	4,037	5,941	12,477	3,541
2041	12	-	-	-	(4,490)	(1,863)	(3,912)	(9,540)	(13,373)	(28,084)	5,130	6,138	12,890	4,490
2042	1	-	-	-	(4,831)	(1,881)	(3,949)	(9,932)	(13,989)	(29,376)	5,505	6,737	14,148	4,831
2042	2	-	-	-	(4,450)	(1,767)	(3,711)	(8,783)	(12,632)	(26,527)	4,868	6,084	12,776	4,450
2042	3	-	-	-	(3,723)	(1,869)	(3,926)	(8,340)	(14,011)	(29,422)	4,623	6,748	14,170	3,723
2042	4	-	-	-	(954)	(1,794)	(3,768)	(6,255)	(13,870)	(29,127)	3,467	6,680	14,028	954
2042	5	-	-	-	(3,325)	(1,907)	(4,005)	(7,677)	(14,683)	(30,835)	4,255	7,072	14,850	3,325
2042	6	-	-	-	(3,989)	(1,876)	(3,939)	(9,443)	(14,361)	(30,158)	5,234	6,916	14,524	3,989
2042	7	-	-	-	(4,811)	(1,948)	(4,090)	(10,477)	(14,840)	(31,163)	5,807	7,147	15,009	4,811
2042	8	-	-	-	(4,558)	(1,962)	(4,120)	(9,906)	(14,799)	(31,078)	5,490	7,127	14,967	4,558
2042	9	-	-	-	(3,655)	(1,855)	(3,896)	(8,245)	(14,056)	(29,518)	4,570	6,770	14,216	3,655
2042	10	-	-	-	(956)	(1,860)	(3,907)	(6,049)	(14,076)	(29,559)	3,353	6,779	14,236	956
2042	11	-	-	-	(3,541)	(1,822)	(3,826)	(7,791)	(13,472)	(28,291)	4,318	6,488	13,625	3,541
2042	12	-	-	-	(4,490)	(1,863)	(3,912)	(9,890)	(13,994)	(29,388)	5,482	6,740	14,154	4,490
2043	1	-	-	-	(4,831)	(1,881)	(3,949)	(11,882)	(14,760)	(30,996)	6,768	7,416	15,573	4,831

Year	Month	UEE_RES_H	UEE_COM_H	UEE_IND_H	UEE_RES_dSHIFT	UEE_COM_dSHIFT	UEE_IND_dSHIFT	UEE_RES_Fon	UEE_COM_Fon	UEE_IND_Fon	UEE_RES_Foff	UEE_COM_Foff	UEE_IND_Foff	UEE_RES_HistOff
2043	2	-	-	-	(4,450)	(1,767)	(3,711)	(10,945)	(13,869)	(29,125)	6,234	6,968	14,633	4,450
2043	3	-	-	-	(3,723)	(1,869)	(3,926)	(9,157)	(14,672)	(30,811)	5,216	7,371	15,480	3,723
2043	4	-	-	-	(954)	(1,794)	(3,768)	(2,346)	(14,081)	(29,570)	1,336	7,075	14,857	954
2043	5	-	-	-	(3,325)	(1,907)	(4,005)	(8,178)	(14,968)	(31,433)	4,658	7,520	15,793	3,325
2043	6	-	-	-	(3,989)	(1,876)	(3,939)	(9,812)	(14,721)	(30,913)	5,589	7,396	15,531	3,989
2043	7	-	-	-	(4,811)	(1,948)	(4,090)	(11,832)	(15,287)	(32,103)	6,739	7,681	16,129	4,811
2043	8	-	-	-	(4,558)	(1,962)	(4,120)	(11,210)	(15,398)	(32,335)	6,385	7,736	16,246	4,558
2043	9	-	-	-	(3,655)	(1,855)	(3,896)	(8,990)	(14,562)	(30,581)	5,121	7,316	15,364	3,655
2043	10	-	-	-	(956)	(1,860)	(3,907)	(2,351)	(14,601)	(30,663)	1,339	7,336	15,406	956
2043	11	-	-	-	(3,541)	(1,822)	(3,826)	(8,709)	(14,301)	(30,031)	4,961	7,185	15,088	3,541
2043	12	-	-	-	(4,490)	(1,863)	(3,912)	(11,044)	(14,622)	(30,706)	6,291	7,346	15,427	4,490
2044	1	-	-	-	(4,831)	(1,881)	(3,949)	(12,291)	(15,352)	(32,240)	7,177	8,008	16,817	4,831
2044	2	-	-	-	(4,450)	(1,767)	(3,711)	(11,322)	(14,426)	(30,294)	6,611	7,525	15,802	4,450
2044	3	-	-	-	(3,723)	(1,869)	(3,926)	(9,472)	(15,261)	(32,048)	5,531	7,960	16,717	3,723
2044	4	-	-	-	(954)	(1,794)	(3,768)	(2,427)	(14,646)	(30,757)	1,417	7,640	16,044	954
2044	5	-	-	-	(3,325)	(1,907)	(4,005)	(8,459)	(15,569)	(32,695)	4,940	8,121	17,054	3,325
2044	6	-	-	-	(3,989)	(1,876)	(3,939)	(10,149)	(15,311)	(32,154)	5,927	7,987	16,772	3,989
2044	7	-	-	-	(4,811)	(1,948)	(4,090)	(12,239)	(15,901)	(33,392)	7,147	8,294	17,418	4,811
2044	8	-	-	-	(4,558)	(1,962)	(4,120)	(11,596)	(16,016)	(33,633)	6,771	8,354	17,544	4,558
2044	9	-	-	-	(3,655)	(1,855)	(3,896)	(9,300)	(15,147)	(31,808)	5,430	7,901	16,592	3,655
2044	10	-	-	-	(956)	(1,860)	(3,907)	(2,432)	(15,187)	(31,894)	1,420	7,922	16,637	956
2044	11	-	-	-	(3,541)	(1,822)	(3,826)	(9,009)	(14,875)	(31,237)	5,261	7,759	16,294	3,541
2044	12	-	-	-	(4,490)	(1,863)	(3,912)	(11,424)	(15,209)	(31,939)	6,671	7,933	16,660	4,490
2045	1	-	-	-	(4,831)	(1,881)	(3,949)	(12,700)	(15,945)	(33,484)	7,586	8,601	18,062	4,831
2045	2	-	-	-	(4,450)	(1,767)	(3,711)	(11,699)	(14,982)	(31,463)	6,988	8,082	16,971	4,450
2045	3	-	-	-	(3,723)	(1,869)	(3,926)	(9,788)	(15,850)	(33,285)	5,846	8,549	17,954	3,723
2045	4	-	-	-	(954)	(1,794)	(3,768)	(2,508)	(15,212)	(31,944)	1,498	8,205	17,231	954
2045	5	-	-	-	(3,325)	(1,907)	(4,005)	(8,741)	(16,170)	(33,957)	5,221	8,722	18,316	3,325
2045	6	-	-	-	(3,989)	(1,876)	(3,939)	(10,487)	(15,902)	(33,395)	6,264	8,578	18,013	3,989
2045	7	-	-	-	(4,811)	(1,948)	(4,090)	(12,647)	(16,515)	(34,681)	7,554	8,908	18,707	4,811
2045	8	-	-	-	(4,558)	(1,962)	(4,120)	(11,982)	(16,634)	(34,931)	7,157	8,972	18,842	4,558
2045	9	-	-	-	(3,655)	(1,855)	(3,896)	(9,609)	(15,731)	(33,036)	5,740	8,486	17,820	3,655
2045	10	-	-	-	(956)	(1,860)	(3,907)	(2,513)	(15,774)	(33,124)	1,501	8,508	17,867	956
2045	11	-	-	-	(3,541)	(1,822)	(3,826)	(9,309)	(15,449)	(32,442)	5,561	8,333	17,500	3,541
2045	12	-	-	-	(4,490)	(1,863)	(3,912)	(11,805)	(15,796)	(33,172)	7,051	8,520	17,893	4,490

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2011	1	-	-	-	-	-
2011	2	-	-	-	-	-
2011	3	-	-	-	-	-
2011	4	-	-	-	-	-
2011	5	-	-	-	-	-
2011	6	-	-	-	-	-
2011	7	-	-	-	-	-
2011	8	-	-	-	-	-
2011	9	-	-	-	-	-
2011	10	-	-	-	-	-
2011	11	-	-	-	-	-
2011	12	-	-	-	-	-
2012	1	-	-	-	-	-
2012	2	-	-	-	-	-
2012	3	-	-	-	-	-
2012	4	-	-	-	-	-
2012	5	-	-	-	-	-
2012	6	-	-	-	-	-
2012	7	-	-	-	-	-
2012	8	-	-	-	-	-
2012	9	-	-	-	-	-
2012	10	-	-	-	-	-
2012	11	-	-	-	-	-
2012	12	-	-	-	-	-
2013	1	-	-	-	-	-
2013	2	-	-	-	-	-
2013	3	-	-	-	-	-
2013	4	-	-	-	-	-
2013	5	-	-	-	-	-
2013	6	-	-	-	-	-
2013	7	-	-	-	-	-
2013	8	-	-	-	-	-
2013	9	-	-	-	-	-
2013	10	-	-	-	-	-
2013	11	-	-	-	-	-
2013	12	-	-	-	-	-
2014	1	-	-	-	-	-
2014	2	-	-	-	-	-
2014	3	-	-	-	-	-
2014	4	-	-	-	-	-
2014	5	-	-	-	-	-
2014	6	-	-	-	-	-
2014	7	-	-	-	-	-
2014	8	-	-	-	-	-
2014	9	-	-	-	-	-
2014	10	-	-	-	-	-
2014	11	-	-	-	-	-
2014	12	-	-	-	-	-
2015	1	-	-	-	-	-
2015	2	-	-	-	-	-
2015	3	-	-	-	-	-
2015	4	-	-	-	-	-
2015	5	-	-	-	-	-
2015	6	-	-	-	-	-
2015	7	-	-	-	-	-

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2015	8	-	-	-	-	-
2015	9	-	-	-	-	-
2015	10	-	-	-	-	-
2015	11	-	-	-	-	-
2015	12	-	-	-	-	-
2016	1	-	-	-	-	-
2016	2	-	-	-	-	-
2016	3	-	-	-	-	-
2016	4	-	-	-	-	-
2016	5	-	-	-	-	-
2016	6	-	-	-	-	-
2016	7	-	-	-	-	-
2016	8	-	-	-	-	-
2016	9	-	-	-	-	-
2016	10	-	-	-	-	-
2016	11	-	-	-	-	-
2016	12	-	-	-	-	-
2017	1	-	-	-	-	-
2017	2	-	-	-	-	-
2017	3	-	-	-	-	-
2017	4	-	-	-	-	-
2017	5	-	-	-	-	-
2017	6	-	-	-	-	-
2017	7	-	-	-	-	-
2017	8	-	-	-	-	-
2017	9	-	-	-	-	-
2017	10	-	-	-	-	-
2017	11	-	-	-	-	-
2017	12	-	-	-	-	-
2018	1	-	-	(84)	(34)	(72)
2018	2	-	-	(148)	(62)	(130)
2018	3	-	-	(212)	(103)	(216)
2018	4	-	-	(182)	(135)	(283)
2018	5	-	-	(325)	(181)	(380)
2018	6	-	-	(463)	(212)	(444)
2018	7	-	-	(596)	(254)	(534)
2018	8	-	-	(646)	(293)	(615)
2018	9	-	-	(619)	(309)	(649)
2018	10	-	-	(449)	(344)	(723)
2018	11	-	-	(731)	(364)	(765)
2018	12	-	-	(1,001)	(407)	(855)
2019	1	-	-	(1,051)	(451)	(947)
2019	2	-	-	(978)	(441)	(927)
2019	3	-	-	(984)	(527)	(1,107)
2019	4	-	-	(698)	(561)	(1,177)
2019	5	-	-	(990)	(639)	(1,341)
2019	6	-	-	(1,225)	(660)	(1,385)
2019	7	-	-	(1,405)	(725)	(1,523)
2019	8	-	-	(1,387)	(766)	(1,608)
2019	9	-	-	(1,229)	(762)	(1,600)
2019	10	-	-	(917)	(801)	(1,682)
2019	11	-	-	(1,268)	(804)	(1,689)
2019	12	-	-	(1,627)	(869)	(1,825)
2020	1	-	-	(1,675)	(915)	(1,921)
2020	2	-	-	(1,583)	(893)	(1,876)

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2020	3	-	-	(1,517)	(1,006)	(2,112)
2020	4	-	-	(1,143)	(1,037)	(2,177)
2020	5	-	-	(1,483)	(1,142)	(2,399)
2020	6	-	-	(1,804)	(1,171)	(2,458)
2020	7	-	-	(2,039)	(1,252)	(2,629)
2020	8	-	-	(1,987)	(1,294)	(2,717)
2020	9	-	-	(1,732)	(1,274)	(2,675)
2020	10	-	-	(1,326)	(1,311)	(2,753)
2020	11	-	-	(1,736)	(1,303)	(2,737)
2020	12	-	-	(2,202)	(1,395)	(2,929)
2021	1	10	20	(2,254)	(1,436)	(3,016)
2021	2	9	19	(2,026)	(1,348)	(2,831)
2021	3	11	22	(1,981)	(1,552)	(3,259)
2021	4	11	22	(1,512)	(1,575)	(3,308)
2021	5	12	24	(1,892)	(1,714)	(3,600)
2021	6	12	25	(2,298)	(1,736)	(3,646)
2021	7	12	26	(2,577)	(1,834)	(3,851)
2021	8	13	27	(2,481)	(1,889)	(3,966)
2021	9	12	26	(2,123)	(1,837)	(3,858)
2021	10	13	27	(1,607)	(1,874)	(3,935)
2021	11	13	26	(2,071)	(1,860)	(3,906)
2021	12	13	28	(2,634)	(1,969)	(4,135)
2022	1	47	98	(2,679)	(2,007)	(4,215)
2022	2	43	91	(2,394)	(1,867)	(3,920)
2022	3	50	104	(2,311)	(2,131)	(4,475)
2022	4	50	105	(1,759)	(2,140)	(4,495)
2022	5	54	114	(2,179)	(2,324)	(4,881)
2022	6	54	114	(2,683)	(2,330)	(4,892)
2022	7	57	119	(3,009)	(2,440)	(5,124)
2022	8	58	123	(2,875)	(2,510)	(5,271)
2022	9	56	118	(2,426)	(2,421)	(5,083)
2022	10	57	120	(1,806)	(2,459)	(5,164)
2022	11	57	119	(2,336)	(2,427)	(5,096)
2022	12	59	125	(2,998)	(2,549)	(5,353)
2023	1	139	292	(3,203)	(2,866)	(6,018)
2023	2	126	265	(2,830)	(2,595)	(5,449)
2023	3	140	295	(2,683)	(2,893)	(6,076)
2023	4	138	289	(2,019)	(2,834)	(5,951)
2023	5	147	308	(2,471)	(3,024)	(6,350)
2023	6	144	302	(3,041)	(2,958)	(6,211)
2023	7	147	309	(3,379)	(3,034)	(6,371)
2023	8	148	312	(3,190)	(3,055)	(6,416)
2023	9	140	294	(2,659)	(2,880)	(6,047)
2023	10	140	294	(1,951)	(2,884)	(6,056)
2023	11	135	284	(2,507)	(2,783)	(5,843)
2023	12	139	292	(3,189)	(2,859)	(6,004)
2024	1	299	628	(3,544)	(3,448)	(7,242)
2024	2	280	587	(3,245)	(3,228)	(6,778)
2024	3	299	629	(2,976)	(3,454)	(7,253)
2024	4	296	622	(2,232)	(3,419)	(7,180)
2024	5	314	660	(2,737)	(3,629)	(7,620)
2024	6	306	643	(3,372)	(3,531)	(7,415)
2024	7	317	666	(3,738)	(3,658)	(7,682)
2024	8	317	666	(3,534)	(3,657)	(7,681)
2024	9	299	629	(2,944)	(3,456)	(7,257)

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2024	10	301	631	(2,158)	(3,470)	(7,287)
2024	11	289	606	(2,778)	(3,330)	(6,994)
2024	12	298	626	(3,530)	(3,441)	(7,225)
2025	1	541	1,136	(3,882)	(4,043)	(8,490)
2025	2	489	1,026	(3,433)	(3,651)	(7,667)
2025	3	542	1,138	(3,260)	(4,049)	(8,503)
2025	4	537	1,127	(2,445)	(4,009)	(8,418)
2025	5	568	1,193	(3,001)	(4,244)	(8,912)
2025	6	556	1,167	(3,691)	(4,151)	(8,716)
2025	7	574	1,205	(4,095)	(4,289)	(9,007)
2025	8	572	1,202	(3,872)	(4,277)	(8,982)
2025	9	544	1,142	(3,223)	(4,062)	(8,531)
2025	10	544	1,143	(2,364)	(4,068)	(8,543)
2025	11	521	1,094	(3,045)	(3,894)	(8,177)
2025	12	541	1,137	(3,866)	(4,045)	(8,494)
2026	1	831	1,746	(4,177)	(4,613)	(9,688)
2026	2	753	1,581	(3,690)	(4,177)	(8,771)
2026	3	837	1,758	(3,501)	(4,645)	(9,755)
2026	4	827	1,736	(2,628)	(4,586)	(9,631)
2026	5	873	1,833	(3,229)	(4,843)	(10,170)
2026	6	858	1,802	(3,964)	(4,761)	(9,998)
2026	7	884	1,857	(4,402)	(4,907)	(10,304)
2026	8	882	1,852	(4,162)	(4,893)	(10,276)
2026	9	838	1,759	(3,464)	(4,648)	(9,760)
2026	10	837	1,757	(2,544)	(4,642)	(9,748)
2026	11	805	1,691	(3,271)	(4,467)	(9,381)
2026	12	834	1,751	(4,155)	(4,627)	(9,717)
2027	1	1,138	2,391	(4,458)	(5,178)	(10,873)
2027	2	1,033	2,170	(3,936)	(4,700)	(9,871)
2027	3	1,152	2,420	(3,730)	(5,241)	(11,006)
2027	4	1,135	2,383	(2,802)	(5,161)	(10,838)
2027	5	1,198	2,516	(3,443)	(5,450)	(11,445)
2027	6	1,178	2,474	(4,228)	(5,358)	(11,251)
2027	7	1,211	2,543	(4,696)	(5,509)	(11,568)
2027	8	1,214	2,549	(4,437)	(5,521)	(11,593)
2027	9	1,150	2,415	(3,694)	(5,230)	(10,984)
2027	10	1,145	2,405	(2,716)	(5,210)	(10,941)
2027	11	1,108	2,327	(3,486)	(5,041)	(10,585)
2027	12	1,145	2,404	(4,431)	(5,207)	(10,935)
2028	1	1,419	2,980	(4,720)	(5,675)	(11,918)
2028	2	1,335	2,804	(4,314)	(5,340)	(11,215)
2028	3	1,436	3,016	(3,950)	(5,745)	(12,064)
2028	4	1,407	2,954	(2,973)	(5,627)	(11,816)
2028	5	1,501	3,152	(3,639)	(6,004)	(12,608)
2028	6	1,468	3,083	(4,476)	(5,872)	(12,332)
2028	7	1,506	3,162	(4,975)	(6,024)	(12,649)
2028	8	1,517	3,185	(4,696)	(6,066)	(12,739)
2028	9	1,429	3,002	(3,915)	(5,718)	(12,007)
2028	10	1,431	3,006	(2,873)	(5,726)	(12,024)
2028	11	1,381	2,901	(3,691)	(5,525)	(11,603)
2028	12	1,419	2,981	(4,695)	(5,677)	(11,922)
2029	1	1,641	3,446	(5,001)	(6,185)	(12,988)
2029	2	1,482	3,112	(4,423)	(5,585)	(11,729)
2029	3	1,648	3,460	(4,196)	(6,211)	(13,043)
2029	4	1,623	3,407	(3,152)	(6,116)	(12,844)

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2029	5	1,727	3,626	(3,862)	(6,508)	(13,667)
2029	6	1,685	3,537	(4,755)	(6,349)	(13,334)
2029	7	1,736	3,647	(5,278)	(6,545)	(13,745)
2029	8	1,745	3,664	(4,985)	(6,576)	(13,810)
2029	9	1,640	3,444	(4,159)	(6,182)	(12,982)
2029	10	1,651	3,467	(3,046)	(6,223)	(13,069)
2029	11	1,589	3,337	(3,918)	(5,989)	(12,578)
2029	12	1,633	3,429	(4,983)	(6,154)	(12,924)
2030	1	1,771	3,719	(5,275)	(6,611)	(13,883)
2030	2	1,599	3,358	(4,665)	(5,970)	(12,537)
2030	3	1,774	3,725	(4,430)	(6,621)	(13,905)
2030	4	1,756	3,687	(3,322)	(6,555)	(13,766)
2030	5	1,863	3,913	(4,074)	(6,957)	(14,609)
2030	6	1,813	3,808	(5,019)	(6,769)	(14,216)
2030	7	1,879	3,945	(5,564)	(7,013)	(14,728)
2030	8	1,878	3,944	(5,259)	(7,012)	(14,725)
2030	9	1,775	3,727	(4,383)	(6,625)	(13,913)
2030	10	1,782	3,742	(3,213)	(6,652)	(13,970)
2030	11	1,710	3,591	(4,135)	(6,384)	(13,407)
2030	12	1,767	3,710	(5,255)	(6,596)	(13,852)
2031	1	1,838	3,860	(5,213)	(6,969)	(14,635)
2031	2	1,660	3,486	(4,610)	(6,293)	(13,215)
2031	3	1,841	3,866	(4,378)	(6,980)	(14,658)
2031	4	1,822	3,827	(3,283)	(6,910)	(14,511)
2031	5	1,929	4,052	(4,030)	(7,315)	(15,361)
2031	6	1,887	3,963	(4,956)	(7,154)	(15,024)
2031	7	1,950	4,095	(5,499)	(7,393)	(15,525)
2031	8	1,945	4,083	(5,200)	(7,373)	(15,482)
2031	9	1,847	3,879	(4,328)	(7,002)	(14,705)
2031	10	1,849	3,884	(3,175)	(7,012)	(14,726)
2031	11	1,770	3,717	(4,089)	(6,711)	(14,094)
2031	12	1,839	3,861	(5,191)	(6,972)	(14,641)
2032	1	1,847	3,879	(4,878)	(7,132)	(14,977)
2032	2	1,728	3,630	(4,467)	(6,674)	(14,016)
2032	3	1,865	3,916	(4,085)	(7,200)	(15,120)
2032	4	1,836	3,856	(3,069)	(7,090)	(14,889)
2032	5	1,939	4,072	(3,771)	(7,487)	(15,722)
2032	6	1,906	4,003	(4,630)	(7,360)	(15,456)
2032	7	1,960	4,116	(5,143)	(7,567)	(15,892)
2032	8	1,964	4,124	(4,859)	(7,584)	(15,926)
2032	9	1,861	3,908	(4,046)	(7,185)	(15,089)
2032	10	1,853	3,892	(2,975)	(7,157)	(15,030)
2032	11	1,793	3,766	(3,818)	(6,925)	(14,541)
2032	12	1,853	3,890	(4,853)	(7,153)	(15,022)
2033	1	1,848	3,880	(4,622)	(7,190)	(15,099)
2033	2	1,677	3,522	(4,080)	(6,527)	(13,707)
2033	3	1,870	3,927	(3,867)	(7,278)	(15,284)
2033	4	1,837	3,857	(2,908)	(7,148)	(15,010)
2033	5	1,949	4,094	(3,566)	(7,587)	(15,932)
2033	6	1,912	4,015	(4,383)	(7,440)	(15,623)
2033	7	1,961	4,118	(4,871)	(7,631)	(16,025)
2033	8	1,975	4,147	(4,598)	(7,685)	(16,139)
2033	9	1,866	3,919	(3,830)	(7,263)	(15,252)
2033	10	1,859	3,904	(2,816)	(7,234)	(15,192)
2033	11	1,799	3,777	(3,614)	(6,999)	(14,699)

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2033	12	1,853	3,891	(4,596)	(7,212)	(15,144)
2034	1	1,852	3,890	(4,465)	(7,227)	(15,176)
2034	2	1,677	3,522	(3,945)	(6,543)	(13,740)
2034	3	1,870	3,927	(3,739)	(7,296)	(15,321)
2034	4	1,832	3,846	(2,814)	(7,146)	(15,006)
2034	5	1,954	4,104	(3,445)	(7,624)	(16,011)
2034	6	1,912	4,015	(4,238)	(7,458)	(15,661)
2034	7	1,961	4,118	(4,710)	(7,650)	(16,064)
2034	8	1,975	4,147	(4,446)	(7,704)	(16,178)
2034	9	1,861	3,909	(3,706)	(7,261)	(15,249)
2034	10	1,864	3,914	(2,720)	(7,271)	(15,270)
2034	11	1,799	3,777	(3,494)	(7,017)	(14,735)
2034	12	1,848	3,881	(4,445)	(7,210)	(15,141)
2035	1	1,857	3,899	(4,427)	(7,250)	(15,224)
2035	2	1,677	3,521	(3,916)	(6,547)	(13,748)
2035	3	1,865	3,916	(3,715)	(7,280)	(15,289)
2035	4	1,836	3,856	(2,791)	(7,169)	(15,055)
2035	5	1,954	4,103	(3,419)	(7,629)	(16,020)
2035	6	1,906	4,003	(4,209)	(7,443)	(15,630)
2035	7	1,965	4,127	(4,673)	(7,672)	(16,112)
2035	8	1,974	4,146	(4,413)	(7,708)	(16,188)
2035	9	1,856	3,898	(3,682)	(7,246)	(15,217)
2035	10	1,868	3,924	(2,696)	(7,295)	(15,319)
2035	11	1,798	3,776	(3,468)	(7,021)	(14,743)
2035	12	1,848	3,880	(4,412)	(7,214)	(15,149)
2036	1	1,852	3,889	(4,414)	(7,232)	(15,187)
2036	2	1,733	3,640	(4,042)	(6,769)	(14,215)
2036	3	1,855	3,895	(3,707)	(7,243)	(15,211)
2036	4	1,836	3,856	(2,780)	(7,171)	(15,058)
2036	5	1,944	4,082	(3,412)	(7,591)	(15,941)
2036	6	1,901	3,992	(4,197)	(7,424)	(15,591)
2036	7	1,965	4,125	(4,656)	(7,672)	(16,111)
2036	8	1,959	4,114	(4,403)	(7,651)	(16,066)
2036	9	1,861	3,908	(3,664)	(7,267)	(15,260)
2036	10	1,863	3,913	(2,688)	(7,277)	(15,281)
2036	11	1,783	3,745	(3,462)	(6,965)	(14,626)
2036	12	1,853	3,890	(4,395)	(7,235)	(15,193)
2037	1	1,852	3,889	(4,431)	(7,232)	(15,188)
2037	2	1,677	3,521	(3,915)	(6,548)	(13,751)
2037	3	1,865	3,916	(3,714)	(7,282)	(15,293)
2037	4	1,841	3,866	(2,788)	(7,190)	(15,099)
2037	5	1,944	4,083	(3,425)	(7,592)	(15,944)
2037	6	1,911	4,014	(4,206)	(7,464)	(15,674)
2037	7	1,970	4,137	(4,670)	(7,693)	(16,155)
2037	8	1,964	4,125	(4,416)	(7,672)	(16,110)
2037	9	1,866	3,918	(3,675)	(7,287)	(15,302)
2037	10	1,864	3,913	(2,699)	(7,277)	(15,282)
2037	11	1,793	3,766	(3,470)	(7,003)	(14,706)
2037	12	1,858	3,901	(4,409)	(7,254)	(15,234)
2038	1	1,847	3,879	(4,435)	(7,213)	(15,148)
2038	2	1,677	3,521	(3,915)	(6,548)	(13,751)
2038	3	1,870	3,926	(3,711)	(7,301)	(15,333)
2038	4	1,841	3,866	(2,788)	(7,190)	(15,099)
2038	5	1,944	4,083	(3,425)	(7,592)	(15,944)
2038	6	1,911	4,014	(4,206)	(7,464)	(15,674)

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2038	7	1,965	4,127	(4,672)	(7,674)	(16,116)
2038	8	1,969	4,136	(4,414)	(7,691)	(16,151)
2038	9	1,866	3,918	(3,675)	(7,286)	(15,301)
2038	10	1,859	3,903	(2,702)	(7,258)	(15,242)
2038	11	1,798	3,776	(3,468)	(7,022)	(14,747)
2038	12	1,858	3,901	(4,408)	(7,254)	(15,234)
2039	1	1,848	3,880	(4,435)	(7,215)	(15,151)
2039	2	1,677	3,522	(3,915)	(6,550)	(13,754)
2039	3	1,870	3,927	(3,711)	(7,303)	(15,336)
2039	4	1,837	3,857	(2,790)	(7,172)	(15,062)
2039	5	1,949	4,094	(3,422)	(7,613)	(15,987)
2039	6	1,912	4,015	(4,206)	(7,465)	(15,677)
2039	7	1,961	4,118	(4,674)	(7,657)	(16,080)
2039	8	1,975	4,147	(4,412)	(7,712)	(16,195)
2039	9	1,866	3,919	(3,675)	(7,288)	(15,305)
2039	10	1,859	3,904	(2,702)	(7,259)	(15,245)
2039	11	1,799	3,777	(3,468)	(7,024)	(14,750)
2039	12	1,853	3,891	(4,410)	(7,237)	(15,197)
2040	1	1,847	3,879	(4,418)	(7,214)	(15,150)
2040	2	1,734	3,641	(4,041)	(6,771)	(14,218)
2040	3	1,860	3,906	(3,703)	(7,264)	(15,254)
2040	4	1,832	3,846	(2,782)	(7,153)	(15,021)
2040	5	1,949	4,093	(3,408)	(7,611)	(15,984)
2040	6	1,902	3,993	(4,196)	(7,426)	(15,594)
2040	7	1,960	4,116	(4,658)	(7,655)	(16,075)
2040	8	1,969	4,136	(4,399)	(7,691)	(16,151)
2040	9	1,851	3,888	(3,670)	(7,230)	(15,183)
2040	10	1,864	3,914	(2,688)	(7,278)	(15,284)
2040	11	1,794	3,767	(3,457)	(7,005)	(14,710)
2040	12	1,843	3,871	(4,398)	(7,198)	(15,115)
2041	1	1,881	3,949	(4,427)	(7,252)	(15,228)
2041	2	1,767	3,711	(3,915)	(6,548)	(13,751)
2041	3	1,869	3,926	(3,718)	(7,263)	(15,252)
2041	4	1,794	3,768	(2,788)	(7,190)	(15,099)
2041	5	1,907	4,005	(3,419)	(7,631)	(16,025)
2041	6	1,876	3,939	(4,212)	(7,425)	(15,593)
2041	7	1,948	4,090	(4,670)	(7,693)	(16,155)
2041	8	1,962	4,120	(4,414)	(7,691)	(16,151)
2041	9	1,855	3,896	(3,678)	(7,267)	(15,261)
2041	10	1,860	3,907	(2,696)	(7,297)	(15,323)
2041	11	1,822	3,826	(3,470)	(7,003)	(14,706)
2041	12	1,863	3,912	(4,410)	(7,235)	(15,194)
2042	1	1,881	3,949	(4,427)	(7,252)	(15,228)
2042	2	1,767	3,711	(3,915)	(6,548)	(13,751)
2042	3	1,869	3,926	(3,718)	(7,263)	(15,252)
2042	4	1,794	3,768	(2,788)	(7,190)	(15,099)
2042	5	1,907	4,005	(3,422)	(7,612)	(15,984)
2042	6	1,876	3,939	(4,209)	(7,445)	(15,634)
2042	7	1,948	4,090	(4,670)	(7,693)	(16,155)
2042	8	1,962	4,120	(4,416)	(7,672)	(16,110)
2042	9	1,855	3,896	(3,675)	(7,287)	(15,302)
2042	10	1,860	3,907	(2,696)	(7,297)	(15,323)
2042	11	1,822	3,826	(3,473)	(6,984)	(14,666)
2042	12	1,863	3,912	(4,409)	(7,255)	(15,235)
2043	1	1,881	3,949	(5,114)	(7,344)	(15,423)

Year	Month	UEE_COM_HistOff	UEE_IND_HistOff	UEE_RES_NET_F	UEE_COM_NET_F	UEE_IND_NET_F
2043	2	1,767	3,711	(4,711)	(6,901)	(14,492)
2043	3	1,869	3,926	(3,941)	(7,300)	(15,331)
2043	4	1,794	3,768	(1,010)	(7,006)	(14,713)
2043	5	1,907	4,005	(3,520)	(7,448)	(15,640)
2043	6	1,876	3,939	(4,223)	(7,325)	(15,382)
2043	7	1,948	4,090	(5,093)	(7,607)	(15,974)
2043	8	1,962	4,120	(4,825)	(7,662)	(16,089)
2043	9	1,855	3,896	(3,869)	(7,246)	(15,216)
2043	10	1,860	3,907	(1,012)	(7,265)	(15,257)
2043	11	1,822	3,826	(3,748)	(7,116)	(14,943)
2043	12	1,863	3,912	(4,753)	(7,276)	(15,279)
2044	1	1,881	3,949	(5,114)	(7,344)	(15,423)
2044	2	1,767	3,711	(4,711)	(6,901)	(14,492)
2044	3	1,869	3,926	(3,941)	(7,300)	(15,331)
2044	4	1,794	3,768	(1,010)	(7,006)	(14,713)
2044	5	1,907	4,005	(3,520)	(7,448)	(15,640)
2044	6	1,876	3,939	(4,223)	(7,325)	(15,382)
2044	7	1,948	4,090	(5,093)	(7,607)	(15,974)
2044	8	1,962	4,120	(4,825)	(7,662)	(16,089)
2044	9	1,855	3,896	(3,869)	(7,246)	(15,216)
2044	10	1,860	3,907	(1,012)	(7,265)	(15,257)
2044	11	1,822	3,826	(3,748)	(7,116)	(14,943)
2044	12	1,863	3,912	(4,753)	(7,276)	(15,279)
2045	1	1,881	3,949	(5,114)	(7,344)	(15,423)
2045	2	1,767	3,711	(4,711)	(6,901)	(14,492)
2045	3	1,869	3,926	(3,941)	(7,300)	(15,331)
2045	4	1,794	3,768	(1,010)	(7,006)	(14,713)
2045	5	1,907	4,005	(3,520)	(7,448)	(15,640)
2045	6	1,876	3,939	(4,223)	(7,325)	(15,382)
2045	7	1,948	4,090	(5,093)	(7,607)	(15,974)
2045	8	1,962	4,120	(4,825)	(7,662)	(16,089)
2045	9	1,855	3,896	(3,869)	(7,246)	(15,216)
2045	10	1,860	3,907	(1,012)	(7,265)	(15,257)
2045	11	1,822	3,826	(3,748)	(7,116)	(14,943)
2045	12	1,863	3,912	(4,753)	(7,276)	(15,279)

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-049

REQUEST:

Refer to the Passty Testimony, Attachment BWP-1. Provide a comparison of Duke Kentucky's service area energy forecast with the service area energy forecast from Duke Kentucky's most recent IRP filing, Case No. 2014-00273.

RESPONSE:

See the table below for average annual growth rates in MWH forecast:

	Residential	Commercial	Total Retail
2014 to 2034 (Case 2014-00273)	0.8%	0.3%	0.6%
2014 to 2034 (passty testimony)	0.6%	0.2%	0.3%

PERSON RESPONSIBLE: Benjamin W. Passty

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-050

REQUEST:

Refer to the Passty Testimony, Attachment BWP-2. Provide a comparison of Duke Kentucky's system seasonal peak load forecast with the seasonal peak load forecast from Duke Kentucky's most recent IRP filing.

RESPONSE:

See the table below for average annual growth rates in MWH forecast:

	Total Retail After Impacts
2014 to 2034 (Case 2014-00273)	0.6%
2014 to 2034 (Passty testimony)	0.3%

PERSON RESPONSIBLE: Benjamin W. Passty

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-051

REQUEST:

Refer to the Direct Testimony of Anthony J. Platz ("Platz Testimony"), page 5, which indicates that Duke Kentucky's electric delivery system is forecasted to grow 13.7 percent from $426,635,808 to $485,008,652. Refer also to Passty Testimony, page 10, which shows that Duke Kentucky's projected load growth is 0.04 percent between 2017 and 2022, and the projected rate of growth in peak demand is negligible. Explain why Duke Kentucky's electric delivery system is forecasted to continue to grow while experiencing very low load growth.

RESPONSE:

While the Company is experiencing little load growth across its system in the aggregate, Duke Energy Kentucky continues to experience localized load growth that requires infrastructure expansion in certain areas of its system in order to serve customers growing needs. It is not uncommon to see load growth in one particular area that necessitates investment and expansion to meet the localized customer demand, that, on an aggregate basis is otherwise offset by another areas of the system that are demonstrating declining load or is offset by energy efficiency across the system. If the existing facilities in the area that is experiencing the load growth are not sufficient to meet customer need, the Company must make prudent investments in that area, notwithstanding the fact that there is declining load in some other part of the Company's delivery system.

PERSON RESPONSIBLE: Tony Platz

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-052

REQUEST:

Refer to the Platz Testimony, page 9. What are the anticipated cost savings through March 2022 with respect to the Distribution Outage Management System functions as a result of the AMI deployment?

RESPONSE:

Duke Energy Kentucky's estimated cost savings from the AMI deployment for avoided restoration costs (due to the DOMS functions referenced on page 9 of Platz Testimony) are incorporated as pro forma adjustments in this case as shown on Lines and 12 of WPD-2.26a.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-053

REQUEST:

Refer to the Platz Testimony, page 15.

a. Provide an explanation for the increase in transmission capital expenditures from 2016 to 2017.

b. Provide an explanation for the increase in distribution capital expenditures from 2016 to 2017, and from 2017 to 2018.

RESPONSE:

a. There are two primary drivers for the increase in transmission capital expenditures from 2016 – 2017. Namely, system outage constraints and increase proactive replacement of obsolete and deteriorated equipment.

1. System Outage Constraints: During the time period between 2014 – 2016, several projects originally planned for this timeframe were deferred into future years, 2017 and beyond, due to system outage constraints.
2. Increase Proactive Replacements: Increased proactive replacements of several key substation components such as: outdoor distribution switchgear replacements, power transformer relay protection upgrades, 69kV line relay and breaker replacements, and Cyber Security improvements.

b. Duke Energy Kentucky has experienced Commercial and Industrial load growth such that much of the existing local infrastructure has been fully utilized. New and expanding Commercial and Industrial business have committed to installing new facilities that require increased infrastructure capabilities to meet the growing customer requests. The increase in distribution capital expenditures represents the investment in new substation and line capacity required to serve regional load growth while providing safe, reliable electrical power.

Additionally between 2016 and 2017, Duke Energy Kentucky increased investments to proactively replace aging infrastructure such as cable, switchgear, and conductor.

PERSON RESPONSIBLE: Tony Platz

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-054

REQUEST:

Refer to the Platz Testimony, page 19. Provide the additional reliability regulations that Duke Kentucky believes could impose additional compliance costs.

RESPONSE:

The Company is not aware of any at this time. The reference was for the possibility of new and additional reliability regulations that could be imposed through commission mandated programs and/or requirements.

PERSON RESPONSIBLE: Tony Platz

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-055

REQUEST:

Refer to the Platz Testimony, page 25. State whether there are any other Kentucky jurisdictional electric utilities that have a Commission-authorized program similar to Duke Kentucky's proposed Rider DCI.

RESPONSE:

Duke Energy Kentucky is not aware of any other Kentucky utilities with a similar Rider DCI. The Company is aware of other jurisdictional gas utilities with a similar capital replacement riders such as for pipeline replacement programs. The justification for such a program, to enhance system reliability is the same.

PERSON RESPONSIBLE: William Don. Wathen Jr.

STAFF-DR-02-056

REQUEST:

Refer to the Platz Testimony, pages 36-37 and the Application, Volume 1, Tabs 23 and 28.

a. Explain whether the amounts shown for projected capital spending on Tab 28 should agree with the line item on Tab 23 titled Normal Recurring Construction.

b. If the response to a. above is negative, explain why and describe in detail what is meant by Normal Recurring Construction.

RESPONSE:

a. Yes, the amounts on Tab 23 titled Normal Recurring Construction are incorrect and should equal the amounts on Tab 28 including AFUDC. Please see Staff-DR-02-056 ATTACHMENT for revised schedule.

b. n/a

PERSON RESPONSIBLE: Robert H Pratt

Duke Energy Kentucky, Inc.
Case No. 2017-00321
Capital Expenditure Budget
Years 2017 - 2019

Line No.	Project ID/Description	CWIP Balance @ 12/31/16	Projected Expenditures 2017	2018	2019
1	NORMAL RECURRING CONSTRUCTION	18,729,420	55,553,005	76,249,194	40,725,309
2					
3	WD101209 - WGS CT 1 Overhaul #2	3,160,770	7,314,540	0	0
4	EB021422 - Precipitator Rebuild	627,694	8,749,392	26,224,855	0
5	WDC00004 - Install Fuel Oil System	160,162	3,366,990	36,621,265	15,000,000
6	EB020578 - East Bend 2 Dual Fuel Cofiring	0	1,543,412	2,141,357	4,013,122
7	EB020290 - Lined Retention Basin WEST	1,025,696	736,539	19,089,303	240,014
8	EB020745 - Lined Retention Basin EAST	0	0	75,313	4,092,541
9	EB020298 - East Bend SW / PW REROUTE	970,733	6,656,571	14,671,999	305,047
10	EB021281 - New East Bend Landfill Ph 2 of 8	0	1,052,812	2,512,716	12,522,926
11	EB021410 - Dry Bottom Ash Conversion	1,623,170	8,346,702	9,739,344	0
12	EBS01243 - New East Bend Landfill Ph 1 of 8	27,216,024	17,053,446	0	0
13	Advanced Metering Infrastructure	0	11,134,409	12,305,233	0
14	Solar Generation Facilities	34,936	13,431,325	1,160,870	0
15	TOTAL	53,548,604	134,939,143	200,791,451	76,898,959

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-057

REQUEST:

Refer to the Pratt Testimony, 3. Provide a comparison of the 2017 original and amended budget and explain any differences.

RESPONSE:

There is no amended budget for 2017. The Company relied upon the original budget for 2017, as adjusted and described in the Direct Testimony of Mr. Pratt. The adjustments include, but are not limited to:

- Delays in the anticipated deployment of AMI due to the Commission's Order being received in late May 2017;
- Adjustments to capital spend and timing of new plant in-service impacted Depreciation;
- Adjustments to capital spend and timing of new plant in-service impacted AFUDC within Other Income;
- Adjustments to capital spend resulted in reduced borrowings which impacted Interest Expense; and
- The above adjustments to pre-tax book income and additional changes to book/tax differences impacted Income Taxes.

PERSON RESPONSIBLE: Robert H. Pratt

STAFF-DR-02-058

REQUEST:

Refer to the Pratt Testimony at page 4.

a. Provide the income statement for each of the six-month actual and the six-month projected periods included in the base year.

b. Provide the actual income statement for each of the six-month periods in the year ending November 2016.

c. Describe any difference in the budgeting and forecasting process used in the instant case to those used in Duke Kentucky's prior rate case, Case No. 2006-00172.

RESPONSE:

a. See Volume 14 of the Company's application, WPC-2.1a_BP.

b. See STAFF-DR-02-058b ATTACHMENT

c. There are two primary differences in the budgeting process between the instant case and prior case. The main difference is moving from a one year detailed budgeting process in Case No. 2006-00172 to a two year detailed budgeting process in the current case. The second difference is in the approach taken for budgeting vacancies. In the instant case, vacancies are managed and budgeted by the individual departments versus the 2006 case where vacancies were budgeted centrally by the Budget Oversight department.

PERSON RESPONSIBLE: Beau Pratt / Sarah E. Lawler

Duke Energy Kentucky, Inc.
Monthly Revenues and Expenses
December 2015 through November 2016

KyPSC Case No. 2017-00321
STAFF-DR-01-058b Attachment

Account	Description	Code	FERC	Total	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
403002	Depr-Expense	DEPR	403	30,058,614	2,474,534	2,470,487	2,469,239	2,463,248	2,475,332	2,471,861	2,481,103
403151	Depreciation Expense - ARO Ash	DEPR	403	(2,579,232)	(2,579,232)						
404200	Amort Of Elec Plt - Software	DEPR	404	1,847,612	(59,479)	155,291	168,303	173,738	176,660	195,524	175,438
407354	DSM Deferral - Electric	OTH	407	2,664,668	367,541	673,422	447,596	(576,677)	179,911	192,098	732,309
407407	Carrying Charges	OTH	407	(1,011,332)	(57,664)	(59,702)	(63,889)	(70,112)	(83,334)	(86,417)	(90,433)
408050	Municipal License-Electric	OTHTX	408	17,316		1,924	1,924	1,924	1,924	1,924	1,924
408120	Franchise Tax - Non Electric	OTHTX	408	147					65	10	
408121	Taxes Property-Operating	OTHTX	408	7,465,551	575,000	613,136	613,136	613,136	613,136	613,136	835,354
408150	State Unemployment Tax	OTHTX	408	16,869	263	20,019	5,619	(5,934)	(2,363)	185	292
408151	Federal Unemployment Tax	OTHTX	408	7,198	68	5,439	569	203	133	(46)	109
408152	Employer FICA Tax	OTHTX	408	1,008,828	74,433	86,357	72,117	63,913	123,640	79,032	80,105
408205	Highway Use Tax	OTHTX	408	2,015	799	128			57		
408470	Franchise Tax	OTHTX	408	11,266							
408700	Fed Social Security Tax-Elec	OTHTX	408	2,000	(5,000)	14,000	3,000	6,000	(24,000)	4,000	8,000
408800	Federal Highway Use Tax-Elec	OTHTX	408	521		6			3	2	
408851	Sales & Use Tax Exp	OTHTX	408	47,203	(6)	0	(6,622)	(2)	(1)	1	0
408960	Allocated Payroll Taxes	OTHTX	408	1,026,231	150,294	132,655	100,700	41,207	109,407	85,492	50,306
409102	Sit Exp-Utility	FIT	409	(2,264,674)	(891,352)		244,082	(302,652)	(513,611)	(31,962)	149,262
409104	Current State Income Tax - PY	FIT	409	(179,766)							
409190	Federal Income Tax-Electric-CY	FIT	409	(21,897,447)	(9,334,710)		242,889	(2,466,101)	(3,639,070)	(845,536)	312,409
409191	Fed Income Tax-Electric-PY	FIT	409	1,781,817							
409194	Current FIT Elec - PY Audit	FIT	409	(133,106)							27,344
409195	UTP Tax Expense: Fed Util-PY	FIT	409	(1,669)							(1,669)
410100	DFIT: Utility: Current Year	FIT	410	95,286,458	45,018,106		6,191,905	4,031,686	3,733,864	2,841,583	2,863,205
410102	DSIT: Utility: Current Year	FIT	410	14,642,169	6,672,299		988,520	645,235	597,183	453,219	456,708
410105	DFIT: Utility: Prior Year	FIT	410	4,175,032							
410106	DSIT: Utility: Prior Year	FIT	410	1,117,947							
410109	DFIT:Utility:Prior Year	FIT	410	106,757							
411051	Accretion Expense-ARO Ash Pond	OTH	411	(2,549,552)	(2,549,552)		(372,992)	372,992			
411100	DFIT: Utility: Curr Year CR	FIT	411	(58,439,546)	(31,400,251)		(2,291,614)	(3,108,912)	(529,491)	(918,545)	(1,603,086)
411101	DSIT: Utility: Curr Year CR	FIT	411	(10,314,018)	(5,269,623)		(573,652)	(603,560)	(187,387)	(250,159)	(360,605)
411102	DFIT: Utility: Prior Year CR	FIT	411	(6,083,605)							
411103	DSIT: Utility: Prior Year CR	FIT	411	(934,834)							
411106	DFIT:Utility:Prior Year	FIT	411	26,349							(27,344)
411410	Invest Tax Credit Adj-Electric	FIT	411	(21,991)	(2,339)		(3,542)	(1,771)	(1,833)	(1,786)	(1,787)
440000	Residential	REV	440	127,612,583	9,790,418	11,860,549	12,109,372	9,796,129	8,061,659	7,325,340	11,187,942
440990	Residential Unbilled Rev	REV	440	567,355	(120,000)	864,000	(551,000)	(1,651,000)	100,000	1,338,000	884,051
442100	General Service	REV	442	114,835,307	8,814,268	8,915,105	9,361,429	8,991,031	8,551,441	8,480,963	10,704,435
442190	General Service Unbilled Rev	REV	442	315,975	(410,000)	80,000	(37,000)	(108,000)	83,000	717,000	173,281
442200	Industrial Service	REV	442	53,533,571	4,102,905	4,008,569	4,314,982	4,336,641	4,165,447	4,123,872	5,129,596
442290	Industrial Svc Unbilled Rev	REV	442	117,141	(324,000)	164,000	(76,000)	40,000	(34,000)	447,000	(6,976)
444000	Public St & Highway Lighting	REV	444	1,659,324	134,997	140,873	106,247	136,361	171,011	132,386	142,465
445000	Other Sales to Public Auth	REV	445	21,868,445	1,718,141	1,677,634	1,758,658	1,740,663	1,652,917	1,653,420	1,945,008
445090	OPA Unbilled	REV	445	97,569	(111,000)	78,000	(41,000)	(8,000)	(20,000)	195,000	(4,202)
447150	Sales For Resale - Outside	REV	447	18,889,945	2,020,950	1,819,822	845,896	2,695,955	519,626	1,417,776	1,593,226
447155	I/C Sales for Resale	REV	447	23,471	3,976	3,976	3,719	3,976	3,848	3,976	
448000	Interdepartmental Sales-Elec	REV	448	56,344	3,531	13,079	8,977	2,839	2,124	1,904	1,904
449100	Provisions For Rate Refunds	REV	449	(646,682)	480,873	75,759	36,345	(44,610)	(527,625)	(168,196)	(298,075)
450100	Late Pmt and Forf Disc	REV	450	0	0	0	0	0	0	0	0

Account	Description	Code	FERC	Total	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
451100	Misc Service Revenue	REV	451	274,676	36,321	12,140	20,177	33,702	26,642	20,155	25,513
454200	Pole & Line Attachments	REV	454	176,821		41,939		36	85	(3,900)	138,055
454300	Tower Lease Revenues	REV	454	10,892		444	222		222	222	222
454400	Other Electric Rents	REV	454	810,158	45,323	45,351	45,319	53,614	53,519	53,401	60,767
456025	RSG Rev - MISO Make Whole	REV	456	1,530,861	74,093	101,866	76,529	37,197	63,736	(19)	18,817
456040	Sales Use Tax Coll Fee	REV	456	600	50	50	50	50	50	50	50
456075	Data Processing Service	REV	456	32				32			
456110	Transmission Charge PTP	REV	456	55,224	4,614	4,542	6,770	4,516	3,121	4,098	1,387
456111	Other Transmission Revenues	REV	456	1,556,463	259,736	214,609	279,528	177,812	130,450	(39,602)	15,745
456610	Other Electric Revenues	REV	456	5,000							
456970	Wheel Transmission Rev - ED	REV	456	68,553	5,169	5,199	6,991	6,713	5,486	4,920	5,662
500000	Suprvsn and Engrg - Steam Oper	PO	500	2,569,111	279,018	237,440	216,820	237,679	228,258	274,159	302,608
501110	Coal Consumed-Fossil Steam	Fuel	501	84,173,364	8,187,545	8,935,864	7,462,043	4,980,579		4,818,149	7,152,113
501150	Coal & Other Fuel Handling	PO	501	1,442,341	103,929	156,367	112,496	138,483	85,267	119,175	77,983
501160	Coal Sampling & Testing	PO	501	20,158	1,692	2,224	2,179	2,108	3,057	1,989	1,830
501190	Sale Of Fly Ash-Expenses	PO	501	1,917,898	7,712	10,557	17,787	405,137	254,274	119,785	181,708
501310	Oil Consumed-Fossil Steam	Fuel	501	1,273,530	181,295	81,233	62,906	82,606	3,473	439,774	105,782
501350	Oil Handling Expense	PO	501	4,836							
501996	Fuel Expense	Fuel	501	0	0	0	0	0	0	0	0
502040	COST OF LIME	PO	502	7,054,158	505,475	632,194	601,007	503,179	16,499	376,594	653,961
502100	Fossil Steam Exp-Other	PO	502	3,901,023	259,211	365,158	283,949	209,072	290,099	299,354	302,649
505000	Electric Expenses-Steam Oper	PO	505	731,501	43,475	45,924	47,747	51,657	74,264	60,880	65,326
506000	Misc Fossil Power Expenses	PO	506	2,389,856	514,595	79,231	190,611	124,914	172,092	108,418	103,302
509030	SO2 Emission Expense	EA	509	1,540	168		82	79	59	733	39
509210	Seasonal NOx Emission Expense	EA	509	35,142	786						4,396
509212	Annual NOx Emission Expense	EA	509	92,197	59,541		4,377	6,303	4,869	1,748	1,584
510000	Suprvsn and Engrng-Steam Maint	PM	510	2,147,702	165,259	204,281	185,801	180,180	159,005	157,607	162,006
510100	Suprvsn & Engrng-Steam Maint R	PM	510	49,107	622	1,543	1,497	1,850	22,865	1,986	2,322
511000	Maint Of Structures-Steam	PM	511	2,659,475	435,323	90,200	82,514	185,406	404,659	(12,431)	233,413
511200	Maint Of Structures-Steam - Re	PM	511	4	4						
512100	Maint Of Boiler Plant-Other	PM	512	10,044,438	908,186	624,220	601,960	1,636,184	2,643,733	609,669	1,111,123
513100	Maint Of Electric Plant-Other	PM	513	1,666,613	148,407	62,940	151,889	544,178	764,644	(96,543)	(166,147)
514000	Maintenance - Misc Steam Plant	PM	514	4,572,093	687,637	27,878	142,086	292,792	2,292,524	632,214	19,850
514300	Maintenance - Misc Steam Plant	PM	514	1,793	197	161	282	235	325	205	73
546000	Suprvsn and Enginring-CT Oper	PO	546	394,442	31,379	30,936	29,821	32,632	35,820	35,537	37,146
547100	Natural Gas	Fuel	547	2,367,509	98,011	319,070	79,576	1,837	204,800	58,030	84,690
547150	Natural Gas Handling-CT	PO	547	10,170	697	731	744	1,721	942	712	771
547701	Propane Gas	Fuel	547	5,219	322	311	210	327	463	373	441
548100	Generation Expenses-Other CT	PO	548	6,366	666	581	515	494	370	552	580
548200	Prime Movers - Generators- CT	PO	548	271,387	28,467	20,853	24,737	14,523	28,804	12,072	25,652
549000	Misc-Power Generation Expenses	PO	549	1,065,363	107,027	74,672	100,070	74,975	88,247	73,385	96,271
551000	Suprvsn and Enginring-CT Maint	PM	551	39,560	146	2,548	4,131	3,496	3,585	4,069	3,678
552000	Maintenance Of Structures-CT	PM	552	471,809	65,624	13,640	12,756	27,553	14,117	252,771	(199,206)
553000	Maint-Gentg and Elect Equip-CT	PM	553	1,426,242	61,259	9,758	26,246	8,628	927	78,843	514,146
554000	Misc Power Generation Plant-CT	PM	554	199,855	31,431	16,895	10,515	17,197	10,546	12,107	10,204
555028	Purch Pwr - Non-native - net	PP	555	87,082	72,595			124,326			(20,587)
555190	Capacity Purchase Expense	PP	555	1,820,850	41,850	566,450	301,450	304,150	302,800	304,150	
555202	Purch Power-Fuel Clause	PP	555	31,024,076	(1,520,838)	1,210,165	890,150	4,608,956	8,653,793	3,967,433	3,648,185
556000	System Cnts & Load Dispatching	OPS	556	1,052	10	66	78	125	123	156	105

Account	Description	Code	FERC	Total	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
557000	Other Expenses-Oper	OPS	557	7,499,258	377,574	279,233	405,070	410,061	456,947	625,196	464,921
557450	Commissions/Brokerage Expense	OPS	557	43,132	3,399	3,657	3,502	4,786	4,796	3,562	4,876
557980	Retail Deferred Fuel Expenses	Fuel	557	4,752,388	(1,277,025)	(46,884)	1,223,376	664,480	(1,937,051)	233,163	1,322,590
560000	Supervsn and Engrng-Trans Oper	TO	560	3,431	465	(1,367)	486	377	725	90	466
561100	Load Dispatch-Reliability	TO	561	104,448	8,646	9,085	7,663	9,409	8,617	8,501	8,700
561200	Load Dispatch-Mnitor&OprTrnSys	TO	561	484,848	36,836	40,525	38,730	42,191	39,560	40,492	40,911
561300	Load Dispatch - TransSvc&Sch	TO	561	67,841	4,950	5,504	6,835	6,418	5,387	5,487	5,545
561500	ReliabilityPlanning&StdsDev	TO	561	470	0	470	0	0	0	0	0
562000	Station Expenses	TO	562	112,722	10,151	11,083	5,711	5,840	10,656	10,479	8,483
563000	Overhead Line Expenses-Trans	TO	563	16,244	(139)	937	3,776	376	375	351	351
565000	Transm Of Elec By Others	TO	565	15,505,302	1,330,319	1,159,541	1,107,007	1,348,162	1,137,105	1,162,108	1,433,547
566000	Misc Trans Exp-Other	TO	566	625,792	16,768	22,632	101,857	13,634	94,332	64,824	39,853
566100	Misc Trans-Trans Lines Related	TO	566	1,768		353	401	(49)	263		
567000	Rents-Trans Oper	TO	567	1,668					125		300
569000	Maint Of Structures-Trans	TM	569	43,278	3,693			722	1,389	7,124	8,413
569100	Maint of Computer Hardware	TM	569	2,456	27	147	63	629	46	140	78
569200	Maint Of Computer Software	TM	569	212,926	21,808	22,382	25,473	21,120	23,316	13,600	14,310
570100	Maint Stat Equip-Other- Trans	TM	570	341,389	14,507	34,229	14,401	5,112	75,769	13,471	63,910
570200	Main-Cir BrkrsTrnsf Mtrs-Trans	TM	570	9,896	2,766	1,599	1,574	2,116	1,667	0	0
571000	Maint Of Overhead Lines-Trans	TM	571	413,630	30,142	14,303	29,322	50,229	37,048	105,415	23,293
575700	Market Faciliation-Mntr&Comp	RMO	575	1,699,839	130,908	151,706	132,447	134,918	118,583	112,217	159,884
580000	Supervsn and Engring-Dist Oper	DO	580	76,119	8,516	6,353	5,894	11,030	5,773	5,505	5,483
581004	Load Dispatch-Dist of Elec	DO	581	418,391	32,263	33,416	32,292	46,692	37,866	35,092	35,473
582100	Station Expenses-Other-Dist	DO	582	199,916	26,814	20,714	14,043	11,920	20,556	5,979	18,081
583100	Overhead Line Exps-Other-Dist	DO	583	552,070	190,456	3,774	7,722	20,614	115,868	5,597	26,362
583200	Transf Set Rem Reset Test-Dist	DO	583	122,885	15,511	7,618	8,284	7,964	12,493	7,937	19,292
584000	Underground Line Expenses-Dist	DO	584	388,749	26,311	22,961	30,281	44,726	32,257	40,619	27,257
586000	Meter Expenses-Dist	DO	586	360,916	10,363	12,287	8,907	15,056	27,840	33,591	27,843
587000	Cust Install Exp-Other Dist	DO	587	1,110,866	117,842	112,998	107,115	69,017	127,821	84,935	70,963
588100	Misc Distribution Exp-Other	DO	588	2,400,610	161,313	139,061	837,530	(422,414)	249,548	199,444	210,522
589000	Rents-Dist Oper	DO	589	107,081	(1,170)	328	90,371	889	2,577	2,071	(378)
591000	Maintenance Of Structures-Dist	DM	591	13,751	670		4,846	7	296	2,744	1,036
592100	Maint Station Equip-Other-Dist	DM	592	472,856	16,523	36,313	79,201	72,990	36,940	28,604	61,155
593000	Maint Overhd Lines-Other-Dist	DM	593	6,152,954	892,472	83,956	367,054	645,689	681,753	540,501	519,165
593100	Right-Of-Way Maintenance-Dist	DM	593	50	50	0	0	0	0	0	0
594000	Maint-Underground Lines-Dist	DM	594	282,123	5,039	13,927	23,314	17,175	101,126	16,429	22,544
595100	Maint Line Transfrs-Other-Dist	DM	595	34,335	2,182	1,022	6,040	4,054	7,457	1,962	3,297
596000	Maint-StreetLightng/Signl-Dist	DM	596	408,065	6,177	39,586	38,254	39,723	24,341	54,915	34,569
597000	Maintenance Of Meters-Dist	DM	597	343,798	35,142	36,719	36,043	37,400	38,792	23,700	17,771
598100	Main Misc Dist Plt-Other-Dist	DM	598	81	81						
901000	Supervision-Cust Accts	CO	901	244,111	16,317	22,478	20,267	20,408	23,919	18,450	20,657
902000	Meter Reading Expense	CO	902	832,582	52,948	87,770	58,749	90,819	83,969	44,050	89,397
903000	Cust Records & Collection Exp	CO	903	3,404,693	245,892	212,258	279,129	219,595	467,984	163,114	216,993
903100	Cust Contracts & Orders-Local	CO	903	175,824	19,146	25,003	14,527	18,023	4,267	13,802	14,644
903200	Cust Billing & Acct	CO	903	1,234,911	86,328	75,950	72,070	75,382	71,767	64,782	65,962
903250	Customer Billing-Common	CO	903	(149,909)							
903300	Cust Collecting-Local	CO	903	213,785	20,861	23,810	15,709	20,588	17,191	16,517	16,411
903400	Cust Receiv & Collect Exp-Edp	CO	903	30,177	(1,818)	2,915	2,094	2,738	2,760	2,973	3,949
903750	Common - Operating-Cust Accts	CO	903	884					260	221	67

Account	Description	Code	FERC	Total	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
904001	BAD DEBT EXPENSE	CO	904	407,797	(22,937)	(23,791)	969	38,659	(16,028)	8,857	3,137
904003	Cust Acctg-Loss On Sale-A/R	CO	904	145,407	145,407	156,200	172,522	71,487	60,021	94,350	78,360
904891	IC Loss on Sale of AR VIE	CO	904	(782,252)	(101,045)	(57,269)	(93,344)	(28,021)	(12,134)	(45,991)	(27,264)
905000	Misc Customer Accts Expenses	CO	905	465	71	21	17	4	32	64	11
908000	Cust Asst Exp-Conservation Pro	CSI	908	19						19	
908140	Economic Development	CSI	908	0	0						
908160	Cust Assist Exp-General	CSI	908	31					30	1	
909650	Misc Advertising Expenses	CSI	909	5,900	3	42	1,494	(499)	1,036		1
910000	Misc Cust Serv/Inform Exp	CSI	910	382,012	41,970	52,841	27,229	27,041	26,161	27,043	35,552
910100	Exp-Rs Reg Prod/Svces-CstAccts	CSI	910	277,028	25,751	4,758	9,124	88,936	21,935	16,438	15,036
912000	Demonstrating & Selling Exp	SE	912	825,623	65,574	67,547	72,253	52,453	62,599	78,443	74,817
912300	Economic Development Discount	SE	912	0	0						
913001	Advertising Expense	SE	913	47,299	11,928	911	1,400	1,373	5,667	3,828	3,196
920000	A & G Salaries	AGO	920	6,316,480	856,413	529,203	505,370	720,085	146,145	517,804	758,433
920100	Salaries & Wages - Proj Supt -	AGO	920	2	1	1					
921100	Employee Expenses	AGO	921	241,223	(23,434)	65,608	25,880	10,605	40,573	16,319	14,008
921101	Employee Exp - NC	AGO	921	8	1	0	2	1	0	1	0
921103	Employee Exp - WH	AGO	921	(7)	(7)						
921110	Relocation Expenses	AGO	921	(528)	3	3	41	4	3	4	3
921200	Office Expenses	AGO	921	463,688	82,296	59,479	84	25,806	59,852	19,727	49,924
921300	Telephone And Telegraph Exp	AGO	921	21	5	2	2	3	3	2	0
921400	Computer Services Expenses	AGO	921	259,014	128,718	31,172	(374)	8,692	17,148	9,974	5,622
921540	Computer Rent (Go Only)	AGO	921	84,284	7,796	2,994	3,025	3,293	2,740	2,574	2,673
921600	Other	AGO	921	(183)	31	16	(907)	198	35	47	9
921800	Off Supplies & Exp - Proj Supt	AGO	921	2							
921900	Office Supply And Exp-Partner	AGO	921	4						4	
921980	Office Supplies & Expenses	AGO	921	1,053,161	101,894	84,338	84,903	84,779	79,996	85,621	82,881
922000	Admin Exp Transfer	AGO	922	677							
922100	Admin Exp Transf-Construction	AGO	922	0							
923000	Outside Services Employed	AGO	923	1,644,378	305,588	64,695	114,763	156,738	101,327	97,614	158,620
923100	Outside Svcs Cont -Proj Supt -	AGO	923	10	10						
923980	Outside Services Employee &	AGO	923	(18,911)	(3,651)	682	(1,924)	(2,443)	5,073	(4,042)	(1,336)
924000	Property Insurance	AGO	924	4,904	(273)	395	471	(268)	766	395	(267)
924050	Inter-Co Prop Ins Exp	AGO	924	185,504	16,896	15,328	15,328	15,328	15,328	15,328	15,328
924980	Property Insurance For Corp.	AGO	924	172,281	15,938	14,213	14,213	14,213	14,213	14,213	14,213
925000	Injuries & Damages	AGO	925	189,147	2,152	10,446	19,505	10,080	62,295	9,369	6,890
925051	INTER-CO GEN LIAB EXP	AGO	925	624,762	20,587	54,925	54,925	54,925	54,925	54,925	54,925
925200	Injuries And Damages-Other	AGO	925	10,286	770	860	804	852	886	818	815
925300	Environmental Inj & Damages	AGO	925	1,526					1,526		
925980	Injuries And Damages For Corp.	AGO	925	13,071	1,235	1,076	1,076	1,076	1,076	1,076	1,076
926000	EMPL PENSIONS AND BENEFITS	AGO	926	4,058,541	504,854	314,383	363,735	353,138	334,501	304,260	312,918
926420	Employees' Tuition Refund	AGO	926	0							0
926430	Employees'Recreation Expense	AGO	926	99		55			8	0	10
926490	0Ther Employee Benefits	AGO	926	3,364	3,016						
926600	Employee Benefits-Transferred	AGO	926	2,464,049	461,282	(79,259)	248,926	289,562	187,752	234,962	174,517
928000	Regulatory Expenses (Go)	AGO	928	86							
928006	State Reg Comm Proceeding	AGO	928	699,234	58,032	58,032	58,032	58,032	58,032	58,032	58,032
929000	Duplicate Chrgs-Enrgy To Exp	AGO	929	(54,718)	(4,378)	3,387	(12,814)	(3,019)	(3,642)	(3,234)	(3,252)
929500	Admin Exp Transf	AGO	929	(614,495)	(28,475)	(24,056)	(38,633)	(53,830)	(98,034)	(32,754)	(30,028)

Account	Description	Code	FERC	Total	Dec-15	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16
930150	Miscellaneous Advertising Exp	AGO	930	21,654	2,426	887	2,580	3,060	938	2,020	2,362
930200	Misc General Expenses	AGO	930	455,270	23,964	27,672	29,465	29,635	53,705	33,423	73,219
930210	Industry Association Dues	AGO	930	41,499			41,320				
930220	Exp Of Servicing Securities	AGO	930	11,246	(3)	55	28	(38)	11,449	34	2
930230	Dues To Various Organizations	AGO	930	23,623	1,555	2,973	(416)	(1,304)	928	52	1,861
930240	Director'S Expenses	AGO	930	45,091	8,413	449	230	559	6,083	15,198	55
930250	Buy\Sell Transf Employee Homes	AGO	930	26,553	5,392	2,903	7	3,975	706	1,014	1,337
930600	Leased Circuit Charges-Other	AGO	930	0				0			
930700	Research & Development	AGO	930	4,807			(37)	163	3,990	(2,725)	185
930940	General Expenses	AGO	930	1,998	596	58	104	136	54	85	178
931001	Rents-A&G	AGO	931	290,858	16,877	23,857	25,902	24,107	23,577	26,075	24,336
931008	A&G Rents-IC	AGO	931	821,288	36,935	70,061	72,463	71,698	71,328	70,945	70,826
932000	Maintenance Of Gen Plant-Gas	AGO	932	7							7
935100	Maint General Plant-Elec	AGM	935	19,391	3,307	44	36	10,370	2,206	(78)	585
935200	Cust Infor & Computer Control	AGM	935	99	6	2	1	4	8	4	3
				636,509,363	46,698,731	52,333,310	55,249,741	48,259,043	46,490,181	48,776,929	59,488,576
	Revenues	REV		343,419,628	26,530,365	30,127,506	28,276,211	26,245,657	23,012,759	25,707,766	31,718,873
	OperatingExpenses										
	Fuel Expense	Fuel		92,572,010	7,190,148	9,289,594	8,828,111	5,729,829	(1,728,315)	5,549,489	8,665,616
	Purchased Power	PP		32,932,008	(1,406,393)	1,776,615	1,191,600	5,037,432	8,956,593	4,271,583	3,627,598
	Other Power Supply	OPS		7,543,442	380,983	282,956	408,650	414,972	461,866	628,914	469,902
	Emission Allowances	EA		128,879	60,495	0	4,459	6,382	4,928	2,481	6,019
	Operation										
	Production	PO		21,778,610	1,883,343	1,656,868	1,628,483	1,796,574	1,277,993	1,482,612	1,849,787
	Customer Accounts	CO		5,758,475	461,170	525,345	542,709	529,682	704,008	381,189	482,324
	Customer Service & Information	CSI		664,990	67,724	57,641	37,847	115,478	49,162	43,501	50,589
	Sales Expense	SE		872,922	77,502	68,458	73,653	53,826	68,266	82,271	78,013
	Transmission	TO		16,924,534	1,407,996	1,248,763	1,272,466	1,426,358	1,297,145	1,292,332	1,538,156
	Regional Marketing	RMO		1,699,839	130,908	151,706	132,447	134,918	118,583	112,217	159,884
	Distribution	DO		5,737,603	588,219	359,510	1,142,439	(194,506)	632,599	420,770	440,898
	A&G	AGO		19,544,858	2,603,455	1,336,893	1,628,079	1,879,841	1,255,285	1,549,160	1,850,382
	Other	OTH		(896,216)	(2,239,675)	613,720	10,715	(273,797)	96,577	105,681	641,876
	Maintenance										
	Production	PM		23,278,691	2,504,095	1,054,064	1,219,677	2,897,699	6,316,930	1,640,497	1,691,462
	Transmission	TM		1,023,575	72,943	72,660	70,833	79,928	139,235	139,750	110,004
	Regional Marketing	RMM		0	0	0	0	0	0	0	0
	Distribution	DM		7,708,013	958,336	211,523	554,752	817,038	890,705	668,855	659,537
	A&G	AGM		19,490	3,313	46	37	10,374	2,214	(74)	588
	Operation & Maintenance Expense			104,115,384	8,519,329	7,357,197	8,314,137	9,273,413	12,848,702	7,918,761	9,553,500
	Total Operating Expense			237,291,723	14,744,562	18,706,362	18,746,957	20,462,028	20,543,774	18,371,228	22,322,635
	Depreciation Expense	DEPR		29,326,994	(164,177)	2,625,778	2,637,542	2,636,986	2,651,992	2,667,385	2,656,541
	Amortization of Deferred Expenses										
	Taxes Other Than Income Taxes	OTHTX		9,605,145	795,851	873,664	790,443	720,447	822,001	783,736	976,090
	Income Taxes	FIT		16,865,873	4,792,130	0	4,798,588	(1,806,075)	(540,345)	1,246,814	1,814,437
	Operating Income			50,329,893	6,361,999	7,921,702	1,302,681	4,232,271	(464,663)	2,638,603	3,949,170
	Operating Income - Before Income Taxes			67,195,766	11,154,129	7,921,702	6,101,269	2,426,196	(1,005,008)	3,885,417	5,763,607

Account	Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
403002	Depr-Expense	2,487,630	2,616,157	2,554,860	2,557,548	2,536,615
403151	Depreciation Expense - ARO Ash					
404200	Amort Of Elec Plt - Software	171,485	172,386	181,226	167,823	169,217
407354	DSM Deferral - Electric	563,798	516,743	43,506	(109,504)	(366,075)
407407	Carrying Charges	(93,098)	(96,901)	(100,479)	(103,069)	(106,234)
408050	Municipal License-Electric	1,924	1,924	1,924		
408120	Franchise Tax - Non Electric				72	
408121	Taxes Property-Operating	613,135	613,136	613,136	611,167	538,943
408150	State Unemployment Tax	69	348	665	(2,460)	166
408151	Federal Unemployment Tax	169	153	234	75	92
408152	Employer FICA Tax	78,300	81,059	109,780	87,491	72,601
408205	Highway Use Tax	127			126	778
408470	Franchise Tax					11,266
408700	Fed Social Security Tax-Elec	3,000		(17,000)	3,000	7,000
408800	Federal Highway Use Tax-Elec	498	3	3		6
408851	Sales & Use Tax Exp	53,916	1	(86)	0	2
408960	Allocated Payroll Taxes	80,868	69,529	95,902	36,353	73,518
409102	Sit Exp-Utility	385,201	(25,572)	(1,128,750)	11,036	(160,356)
409104	Current State Income Tax - PY	(728,684)	1,007,542		(458,624)	
409190	Federal Income Tax-Electric-CY	1,951,966	(1,114,923)	(5,212,082)	(157,858)	(1,634,431)
409191	Fed Income Tax-Electric-PY	(4,617,513)	6,399,330		0	
409194	Current FIT Elec - PY Audit		(160,450)			
409195	UTP Tax Expense: Fed Util-PY					
410100	DFIT: Utility: Current Year	2,847,583	6,619,940	13,891,344	3,527,366	3,719,876
410102	DSIT: Utility: Current Year	454,187	1,036,269	2,253,477	495,261	589,811
410105	DFIT: Utility: Prior Year	10,221,000	(6,045,968)			
410106	DSIT: Utility: Prior Year	1,649,099	(975,482)		444,330	
410109	DFIT:Utility:Prior Year		106,757			
411051	Accretion Expense-ARO Ash Pond					
411100	DFIT: Utility: Curr Year CR	(1,768,008)	(4,019,224)	(6,775,479)	(1,824,912)	(4,200,024)
411101	DSIT: Utility: Curr Year CR	(387,213)	(750,435)	(785,073)	(363,256)	(783,055)
411102	DFIT: Utility: Prior Year CR	(5,850,202)	(74,716)		(158,687)	
411103	DSIT: Utility: Prior Year CR	(943,896)			9,062	
411106	DFIT:Utility:Prior Year		53,693			
411410	Invest Tax Credit Adj-Electric	(1,787)	(1,786)	(1,787)	(1,786)	(1,787)
440000	Residential	13,053,909	14,091,722	13,174,849	9,404,319	7,756,375
440990	Residential Unbilled Rev	1,225,308	(338,017)	(825,427)	(1,241,289)	882,729
442100	General Service	10,758,718	10,963,537	10,926,054	9,654,091	8,714,235
442190	General Service Unbilled Rev	203,224	352,589	(269,549)	(377,969)	(90,601)
442200	Industrial Service	4,846,529	4,840,262	4,947,424	4,505,599	4,211,745
442290	Industrial Svc Unbilled Rev	31,443	240,395	(120,340)	(85,209)	(159,172)
444000	Public St & Highway Lighting	143,663	135,954	137,822	126,385	151,160
445000	Other Sales to Public Auth	1,879,237	2,019,555	2,154,423	1,932,452	1,736,337
445090	OPA Unbilled	34,768	102,775	(65,189)	(20,775)	(42,808)
447150	Sales For Resale - Outside	477,256	58,975	3,338,013	2,564,341	1,538,109
447155	I/C Sales for Resale					
448000	Interdepartmental Sales-Elec	7,836	4,085	3,610	3,621	2,834
449100	Provisions For Rate Refunds	(370,919)	(303,058)	(32,948)	171,355	334,417
450100	Late Pmt and Forf Disc	0	0	0	0	0

Account	Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
451100	Misc Service Revenue	15,026	16,530	27,472	16,973	24,025
454200	Pole & Line Attachments				498	108
454300	Tower Lease Revenues	222	8,645	231	231	231
454400	Other Electric Rents	92,931	58,473	91,801	104,669	104,990
456025	RSG Rev - MISO Make Whole	280,422	285,682	125,181	250,139	217,218
456040	Sales Use Tax Coll Fee	50	50	50	50	50
456075	Data Processing Service					
456110	Transmission Charge PTP	5,097	6,730	5,263	4,155	4,931
456111	Other Transmission Revenues	184,734	176,311	188,860	30,975	(62,695)
456610	Other Electric Revenues				5,000	
456970	Wheel Transmission Rev - ED	5,903	6,126	6,291	6,069	4,024
500000	Suprvsn and Engrg - Steam Oper	125,803	158,089	213,166	248,242	47,829
501110	Coal Consumed-Fossil Steam	8,566,703	9,237,044	8,707,997	9,070,472	7,054,855
501150	Coal & Other Fuel Handling	103,357	136,221	172,325	120,613	116,125
501160	Coal Sampling & Testing	2,250	1,739	1,090		
501190	Sale Of Fly Ash-Expenses	179,771	181,815	165,711	205,413	188,228
501310	Oil Consumed-Fossil Steam	80,241	93,929	48,233	40,236	53,822
501350	Oil Handling Expense		1,375	3,061	400	
501996	Fuel Expense	0	0	0	0	0
502040	COST OF LIME	677,997	809,631	764,642	788,414	724,565
502100	Fossil Steam Exp-Other	333,865	313,748	437,761	351,847	454,310
505000	Electric Expenses-Steam Oper	62,822	67,086	78,049	68,233	66,038
506000	Misc Fossil Power Expenses	187,051	239,130	377,508	164,521	128,483
509030	SO2 Emission Expense	63	73	82	86	76
509210	Seasonal NOx Emission Expense	6,970	7,692	7,317	7,750	231
509212	Annual NOx Emission Expense	2,521	2,772	2,636	2,793	3,053
510000	Suprvsn and Engrng-Steam Maint	180,052	176,163	175,503	229,714	172,131
510100	Suprvsn & Engrng-Steam Maint R	2,353	3,013	3,540	3,524	3,992
511000	Maint Of Structures-Steam	125,877	306,141	193,500	412,461	202,412
511200	Maint Of Structures-Steam - Re					
512100	Maint Of Boiler Plant-Other	149,197	577,612	458,893	223,659	500,002
513100	Maint Of Electric Plant-Other	257,982	161,546	79,008	(282,867)	41,576
514000	Maintenance - Misc Steam Plant	184,995	61,682	136,560	(4,863)	98,738
514300	Maintenance - Misc Steam Plant	83	142	41	10	39
546000	Suprvsn and Enginring-CT Oper	36,356	35,659	35,541	27,618	25,997
547100	Natural Gas	443,728	468,989	236,072	302,031	70,675
547150	Natural Gas Handling-CT	756	699	802	805	790
547701	Propane Gas	614	596	752	478	332
548100	Generation Expenses-Other CT	593	578	242	147	1,048
548200	Prime Movers - Generators- CT	25,684	20,247	29,212	19,517	21,619
549000	Misc-Power Generation Expenses	82,678	88,706	82,369	105,167	91,796
551000	Suprvsn and Enginring-CT Maint	2,575	3,217	5,629	3,416	3,070
552000	Maintenance Of Structures-CT	80,381	50,463	77,865	48,471	27,374
553000	Maint-Gentg and Elect Equip-CT	18,212	8,395	22,368	668,266	9,194
554000	Misc Power Generation Plant-CT	26,718	15,448	16,855	14,716	17,223
555028	Purch Pwr - Non-native - net			(89,252)		
555190	Capacity Purchase Expense					
555202	Purch Power-Fuel Clause	2,338,423	2,069,619	3,861,897	45,815	1,250,478
556000	System Cnts & Load Dispatching	57	124	64	64	80

Account	Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
557000	Other Expenses-Oper	723,753	817,684	942,493	870,892	1,125,434
557450	Commissions/Brokerage Expense	3,207	2,949	2,775	2,775	2,848
557980	Retail Deferred Fuel Expenses	(97,359)	(573,626)	249,667	855,656	4,135,401
560000	Supervsn and Engrng-Trans Oper	975	660	142	202	210
561100	Load Dispatch-Reliability	8,641	8,985	8,646	8,681	8,874
561200	Load Dispatch-Mnitor&OprTrnSys	40,856	41,253	40,771	41,083	41,640
561300	Load Dispatch - TransSvc&Sch	5,450	5,602	5,503	5,529	5,631
561500	ReliabilityPlanning&StdsDev	0	0	0	0	0
562000	Station Expenses	13,849	8,682	13,022	9,204	5,562
563000	Overhead Line Expenses-Trans	513	348	360	350	8,646
565000	Transm Of Elec By Others	1,294,825	1,316,253	1,478,542	1,319,070	1,418,823
566000	Misc Trans Exp-Other	83,439	38,608	30,935	96,385	22,525
566100	Misc Trans-Trans Lines Related	283	309	55	74	79
567000	Rents-Trans Oper	150	300		300	493
569000	Maint Of Structures-Trans	4,171	3,198	11,492	356	2,720
569100	Maint of Computer Hardware	704	30	110	16	466
569200	Maint Of Computer Software	14,845	14,515	14,127	14,561	12,869
570100	Maint Stat Equip-Other- Trans	41,592	15,337	32,635	17,392	13,034
570200	Main-Cir BrkrsTrnsf Mtrs-Trans	174				
571000	Maint Of Overhead Lines-Trans	6,728	82,914	14,803	4,383	15,050
575700	Market Faciliation-Mntr&Comp	170,872	171,395	173,280	128,530	115,099
580000	Supervsn and Engring-Dist Oper	5,250	4,698	3,625	4,517	9,475
581004	Load Dispatch-Dist of Elec	35,532	33,930	29,719	33,007	33,109
582100	Station Expenses-Other-Dist	14,370	20,776	26,992	10,608	9,063
583100	Overhead Line Exps-Other-Dist	17,357	28,436	207,902	(73,511)	1,493
583200	Transf Set Rem Reset Test-Dist	8,233	8,319	10,892	8,088	8,254
584000	Underground Line Expenses-Dist	23,591	50,009	29,450	35,595	25,692
586000	Meter Expenses-Dist	28,734	27,551	42,144	52,844	73,756
587000	Cust Install Exp-Other Dist	89,257	97,751	134,896	51,456	46,815
588100	Misc Distribution Exp-Other	194,545	210,627	166,792	197,028	256,614
589000	Rents-Dist Oper	2,746	1,308	2,560	12,827	(7,048)
591000	Maintenance Of Structures-Dist	686	1,615	179	1,334	338
592100	Maint Station Equip-Other-Dist	26,035	30,655	48,117	22,608	13,715
593000	Maint Overhd Lines-Other-Dist	561,073	358,790	728,311	407,884	366,306
593100	Right-Of-Way Maintenance-Dist	0	0	0	0	0
594000	Maint-Underground Lines-Dist	30,218	15,788	26,188	18,455	(8,080)
595100	Maint Line Transfrs-Other-Dist	1,412	3,518	(685)	1,878	2,198
596000	Maint-StreetLightng/Signl-Dist	22,528	25,431	25,595	31,186	65,760
597000	Maintenance Of Meters-Dist	21,320	21,353	31,684	22,869	21,005
598100	Main Misc Dist Plt-Other-Dist					
901000	Supervision-Cust Accts	20,111	21,346	25,343	19,689	15,126
902000	Meter Reading Expense	63,723	65,361	87,141	43,011	65,644
903000	Cust Records & Collection Exp	212,430	378,926	321,214	276,440	410,718
903100	Cust Contracts & Orders-Local	5,234	15,699	17,832	11,444	16,203
903200	Cust Billing & Acct	57,032	70,032	204,897	192,288	198,421
903250	Customer Billing-Common			(546,705)	182,346	214,450
903300	Cust Collecting-Local	8,951	18,287	21,866	15,057	18,537
903400	Cust Receiv & Collect Exp-Edp	2,236	3,175	3,467	2,768	2,920
903750	Common - Operating-Cust Accts	186	61	70	19	

Account	Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
904001	BAD DEBT EXPENSE	5,131	(3,718)	548,535	(182,027)	51,010
904003	Cust Acctg-Loss On Sale-A/R	170,649	137,982	(941,571)		
904891	IC Loss on Sale of AR VIE	(108,395)	(76,831)	(97,455)	(85,268)	(49,235)
905000	Misc Customer Accts Expenses	25	57	64	99	
908000	Cust Asst Exp-Conservation Pro					
908140	Economic Development					
908160	Cust Assist Exp-General					
909650	Misc Advertising Expenses		1,177		2,422	224
910000	Misc Cust Serv/Inform Exp	31,318	25,586	28,547	28,255	30,469
910100	Exp-Rs Reg Prod/Svces-CstAccts	16,671	12,745	25,471	17,449	22,714
912000	Demonstrating & Selling Exp	72,410	66,042	59,849	65,237	88,399
912300	Economic Development Discount					
913001	Advertising Expense	3,500	5,278	4,126	1,347	4,745
920000	A & G Salaries	444,050	433,397	423,336	469,617	512,627
920100	Salaries & Wages - Proj Supt -					
921100	Employee Expenses	29,557	5,574	26,094	56,099	(25,660)
921101	Employee Exp - NC	0	1	0	0	2
921103	Employee Exp - WH					
921110	Relocation Expenses	(602)	3	3	2	5
921200	Office Expenses	27,840	35,582	51,048	28,157	23,893
921300	Telephone And Telegraph Exp	1	1	1	0	1
921400	Computer Services Expenses	13,518	15,211	13,159	10,203	5,971
921540	Computer Rent (Go Only)	1,954	2,063	49,226	2,007	3,939
921600	Other	16	56	189	59	68
921800	Off Supplies & Exp - Proj Supt		2			
921900	Office Supply And Exp-Partner					
921980	Office Supplies & Expenses	86,981	96,632	82,596	96,354	86,186
922000	Admin Exp Transfer		677		0	
922100	Admin Exp Transf-Construction			0		
923000	Outside Services Employed	138,657	84,513	170,808	109,480	141,575
923100	Outside Svcs Cont -Proj Supt -					
923980	Outside Services Employee &	1,392	(3,306)	(1,227)	(5,373)	(2,756)
924000	Property Insurance	2,591	395	(268)	395	572
924050	Inter-Co Prop Ins Exp	15,328	15,328	15,328	15,328	15,328
924980	Property Insurance For Corp.	14,213	14,213	14,213	14,213	14,213
925000	Injuries & Damages	14,612	10,565	12,520	21,833	8,880
925051	INTER-CO GEN LIAB EXP	54,925	54,925	54,925	54,925	54,925
925200	Injuries And Damages-Other	912	897	886	917	869
925300	Environmental Inj & Damages					
925980	Injuries And Damages For Corp.	1,076	1,076	1,076	1,076	1,076
926000	EMPL PENSIONS AND BENEFITS	313,280	315,045	330,334	304,889	307,204
926420	Employees' Tuition Refund					
926430	Employees'Recreation Expense	24				2
926490	0Ther Employee Benefits			348		
926600	Employee Benefits-Transferred	192,917	202,343	171,835	119,876	259,336
928000	Regulatory Expenses (Go)				86	
928006	State Reg Comm Proceeding	58,602	58,602	58,602	58,602	58,602
929000	Duplicate Chrgs-Enrgy To Exp	(8,870)	(5,042)	(4,970)	(5,158)	(3,726)
929500	Admin Exp Transf	(43,014)	(41,648)	(63,928)	(117,477)	(42,618)

Account	Description	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16
930150	Miscellaneous Advertising Exp	852	999	2,394	1,562	1,574
930200	Misc General Expenses	15,465	36,854	77,455	27,536	26,877
930210	Industry Association Dues		179			
930220	Exp Of Servicing Securities	0	(122)	424	(541)	(42)
930230	Dues To Various Organizations			3,917	5,318	8,739
930240	Director'S Expenses	6,742	793	763	5,491	315
930250	Buy\Sell Transf Employee Homes	1,419	3,525	3,622	1,087	1,566
930600	Leased Circuit Charges-Other					
930700	Research & Development	457	719	131	441	1,483
930940	General Expenses	143	255	295	59	35
931001	Rents-A&G	24,232	31,040	25,267	24,442	21,146
931008	A&G Rents-IC	71,996	71,139	70,611	71,626	71,660
932000	Maintenance Of Gen Plant-Gas					
935100	Maint General Plant-Elec	840	1,371	4	154	552
935200	Cust Infor & Computer Control	9	9	(1)	44	10
		59,779,521	59,137,239	61,733,677	50,891,420	47,670,995
	Revenues	32,875,357	32,727,321	33,813,891	27,055,680	25,328,242
	OperatingExpenses					
	Fuel Expense	8,993,927	9,226,932	9,242,721	10,268,873	11,315,085
	Purchased Power	2,338,423	2,069,619	3,772,645	45,815	1,250,478
	Other Power Supply	727,017	820,757	945,332	873,731	1,128,362
	Emission Allowances	9,554	10,537	10,035	10,629	3,360
	Operation					
	Production	1,818,983	2,054,723	2,361,479	2,100,937	1,866,828
	Customer Accounts	437,313	630,377	(355,302)	475,866	943,794
	Customer Service & Information	47,989	39,508	54,018	48,126	53,407
	Sales Expense	75,910	71,320	63,975	66,584	93,144
	Transmission	1,448,981	1,421,000	1,577,976	1,480,878	1,512,483
	Regional Marketing	170,872	171,395	173,280	128,530	115,099
	Distribution	419,615	483,405	654,972	332,459	457,223
	A&G	1,481,266	1,442,486	1,591,013	1,373,131	1,553,867
	Other	470,700	419,842	(56,973)	(212,573)	(472,309)
	Maintenance					
	Production	1,028,425	1,363,822	1,169,762	1,316,507	1,075,751
	Transmission	68,214	115,994	73,167	36,708	44,139
	Regional Marketing	0	0	0	0	0
	Distribution	663,272	457,150	859,389	506,214	461,242
	A&G	849	1,380	3	198	562
	Operation & Maintenance Expen:	8,132,389	8,672,402	8,166,759	7,653,565	7,705,230
	Total Operating Expense	20,201,310	20,800,247	22,137,492	18,852,613	21,402,515
	Depreciation Expense	2,659,115	2,788,543	2,736,086	2,725,371	2,705,832
	Amortization of Deferred Expenses					
	Taxes Other Than Income Taxes	832,006	766,153	804,558	735,824	704,372
	Income Taxes	3,211,733	2,054,975	2,241,650	1,521,932	(2,469,966)
	Operating Income	5,971,193	6,317,403	5,894,105	3,219,940	2,985,489
	Operating Income - Before Income T	9,182,926	8,372,378	8,135,755	4,741,872	515,523

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

PUBLIC STAFF-DR-02-059
(As to Attachment Only)

REQUEST:

Refer to the Pratt Testimony, page 8, lines 21-23 and page 9, lines 1-7. Also, refer to the Direct Testimony of John J. Spanos ("Spanos Testimony"), page 2, lines 10-14, page 16, and the 2016 Depreciation Study, Part 1, page 9 of 346. Finally, refer to the Lee Testimony, pages 14 and 15.

a. Confirm that the depreciation rate(s) utilized in the test year for Woodsdale has been recomputed in the 2016 Depreciation Study and is reflected as such in the test-year revenue requirement.

b. For East Bend and Woodsdale, provide the depreciation rate and depreciation expense by unit in the format (by account number) listed on page 55 of 346 of the Spanos Testimony for calendar year 2016, the base period, and test year.

c. Refer to the Spanos Testimony at page 16. What is the remaining life of the surviving assets at Miami Fort Unit 6?

d. Explain further what is meant by the following statement on page 9 of the Depreciation Study: "In order to achieve a more stable accrual for general and common plant accounts in the future, I have recommended a five-year amortization to adjust unrecovered reserve."

e. Identify by account number and name the accounts referenced in the statement listed in item d. above.

f. Provide the capacity factors for each unit at Woodsdale for the ten years ending in 2016.

g. What consideration was given to the capacity factors in the Depreciation Study?

h. When will East Bend be fully depreciated?

i. Does the test period contain depreciation for East Bend?[1] If so, provide the amount and an explanation of how it determined.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment Only)

a. The depreciation rates for Woodsdale were recomputed in the 2016 Depreciation Study. All changes in depreciation rates are reflected in the test-year revenue requirement through forecasted period pro forma adjustment at Schedule D-2.24.

b. See STAFF-DR-02-059(b) Attachment.

c. The assets at Miami Fort Unit 6 have been taken out of service. The remaining value is related to the terminal net salvage to be incurred.

d. The reference in this data request is actually stated on page 18 of Spanos testimony which explains the process of determining the unrecovered reserve amortization. Amortization accounting is intended to produce depreciation rates for certain general plant accounts that match the established amortization period. For example, an account that has an amortization period should have a rate of 5 percent. In order to achieve that constant or stable rate and properly implement amortization accounting which includes systematic retirements at the end of the amortization period, the accumulated depreciation must be properly aligned with

[1] Case No. 2015-00120, *Application of Duke Energy Kentucky, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Depreciation Expense of the East Bend Unit 2 Generating Station* (Ky. PSC Aug. 20, 2015).

the surviving plant. The Depreciation Study includes the segregation of the accumulated depreciation in order to meet the proper recovery of current and future assets by account. The unrecovered reserve amount is a component of that segregation. Consider Account 394 as an example of the process. The plant surviving as of December 31, 2016 is $2,027,306.34 with an accumulated depreciation of 415,617 and 25 year amortization period. However, in order to achieve a 4 percent rates(1/25 years) based on the surviving vintage plant balances for current assets as well as future assets, the accumulated depreciation needs to be 458,617. Therefore, to insure full recovery of the assets as well as produce a constant/stable 4 percent rate the reserve is segregated into two parts: 458,617 for establishing a rate and (43,000) which is separately amortized over 5 years.

e. The accounts included in this unrecovered reserve adjustment are as follows:

1910 Office Furniture and Equipment

1911 Electronic Data Processing

1940 Tools, Shop and Garage Equipment

1970 Communication Equipment

1980 Miscellaneous Equipment

3910 Office Furniture and Equipment

3911 Electronic Data Processing

3940 Tools, Shop and Garage Equipment

3970 Communication Equipment

The unrecovered reserve adjustment amount for each account is listed on pages 56 and 57 of 346 in the Depreciation Study.

f. See STAFF-DR-02-059(f) Confidential Attachment, which is being filed under seal of a Petition for Confidential Treatment.

g. The operation and maintenance characteristics of generating units, as discussed with company personnel and observed during site visits, are what is most relevant to the estimates made for the Depreciation Study. The energy output that a capacity factor represents is only tangentially related to the relevant data for a Depreciation Study; therefore, specific capacity factor values were given consideration for the purposes of the Depreciation Study, but not the focus.

h. At this time, the expectation is that East Bend will be fully depreciated by 2041 which is set forth as the probable retirement date in the Depreciation Study.

i. Yes, the test period includes depreciation for East Bend. The test period depreciation expense for East Bend is $20,334,436. The calculation of this amount is within Schedule B-3.2. East Bend is the only plant in Steam Production. This number excludes the $490,618 of annual amortization related to the East Bend regulatory asset which is calculated at Schedule D-2.21.

PERSON RESPONSIBLE: Cynthia S. Lee/ Robert H. Pratt (a) (b) (i)
John J. Spanos (c) (d) (e) (g) (h)
Joseph A. Miller (f)

East Bend Unit 2

Account	Calendar Year 2016		Base Period		Forecasted Test Year	
	Depreciation Expense	Depreciation Rate	Depreciation Expense	Depreciation Rate	Depreciation Expense	Depreciation Rate
Steam Production Plant						
3110 - Structures and Improvements	884,203	1.28%	912,840	1.28%	1,812,832	2.54%
3120 - Boiler Plant Equipment	10,394,166	2.32%	9,356,882	2.32%	11,253,039	2.54%
3123 - Boiler Plant Equipment - SCR Catalyst	779,017	15.28%	19,781	15.28%	278,081	5.13%
3140 - Turbogenerator Units	2,269,060	2.26%	2,270,515	2.26%	2,652,787	2.66%
3150 - Accessory Electric Equipment	759,745	1.72%	774,438	1.72%	1,117,487	2.43%
3160 - Miscellaneous Power Plant Equipment	372,067	2.15%	415,983	2.15%	737,109	3.64%
Forecasted projects not classified (**Note 1**)	-		203,531	Various	2,483,211	2.60%
Depreciation Deferral/Amortization (**Note 2**)	(4,522,344)		(2,182,184)		490,618	
Total Steam Production Plant	**10,935,913**		**11,771,786**		**20,825,164**	

Woodsdale Units 1-6

Account	Calendar Year 2016		Base Period		Forecasted Test Year	
	Depreciation Expense	Depreciation Rate	Depreciation Expense	Depreciation Rate	Depreciation Expense	Depreciation Rate
Other Production Plant						
3401 - Rights of Way	23,656	3.63%	23,656	3.63%	24,568	3.77%
3410 - Structures and Improvements	738,389	2.04%	736,640	2.04%	912,483	2.53%
3420 - Fuel Holders, Producers, and Accessories	275,924	1.75%	275,930	1.75%	340,823	2.17%
3440 - Generators	4,974,111	2.38%	4,896,916	2.38%	7,541,891	3.48%
3450 - Accessory Electric Equipment	375,901	1.80%	386,285	1.80%	872,916	4.03%
3460 - Miscellaneous Power Plant Equipment	89,517	2.00%	93,086	2.00%	186,148	4.01%
Forecasted projects not classified (**Note 1**)	-		38,700	Various	730,354	3.34%
Total Other Production Plant	**6,477,498**		**6,451,213**		**10,609,183**	

Note 1: For forecated periods (June 2017-November 2017 in base period and entire test year), projects are not forecasted by utility account and for purposes of modeling, average depreciation rates are applied.

Note 2: As approved in Case No. 2015-00120, DEK began deferring depreciation related to the East bend acquisition. The forecasted period for June 2017-November 2017 that is included in the base period , forecasts depreciation net of the deferral. The deferrals for the actual periods are shown above.

STAFF-DR-02-059(f) CONFIDENTIAL ATTACHMENT IS BEING FILED UNDER SEAL OF A PETITION FOR CONFIDENTIAL TREATMENT

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 27, 2017

STAFF-DR-02-060

REQUEST:

Refer to the Pratt Testimony, page 10. Also, refer to the Silinski Testimony, page 15.

a. The Pratt Testimony states that the non-union labor increase was 3.5 percent, whereas the Silinski Testimony states the 2017 merit budget increase was 3.0 percent. Explain the discrepancy in the non-union labor cost increases.

b. Provide the wage increase in the six-month actual period and the six-month projected periods in the base period.

c. State what the wage increase(s) and timeframe(s) for non-union employees are for the test period.

RESPONSE:

a. Duke Energy's non-union labor budget was 3.5%, 3.0% of which was allocated for the merit budget. The remaining 0.5% was allocated for any pay increases outside of merit throughout the year.

b. The wage increase for non-union employees during the six-month actual period in the base period includes a 3.0% merit increase. The remainder of the labor budget, 0.5%, will be used throughout the six-month actual period and the six-month projected period.

c. Assuming the past is an indicator of the future, we assume a 3.5% total wage increase during the test period, 3.0% of which will be associated with merit, paid

in March 2019, and the remaining 0.5% associated with any pay increases outside of merit throughout the year.

PERSON RESPONSIBLE: Tom Silinski

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-061

REQUEST:

Refer to the Pratt Testimony, page 11, regarding property tax expense and Schedule 3-2.14. Provide a breakdown of the State and Other Taxes for the base period and text period.

RESPONSE:

Please see Schedule C-2.1, page 6 of 14, for the base period and Schedule C-2.1, page 13 of 14, for the forecasted test period.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-062

REQUEST:

Refer to the Direct Testimony of Bruce L. Sailers, ("Sailers Testimony"), page 9, which states, "Duke Energy Kentucky's proposed rates in this case make reasonable movement toward reflecting the cost of service developed and sponsored by Mr. Ziolkowski." Explain whether Mr. Sailers finds a 149 percent increase in the residential customer charge makes a reasonable movement toward reflecting the cost of service, and whether the increase comports with the Commission's position with regard to gradualism.

RESPONSE:

Mr. Sailers' proposed rate design fully reflects the cost of service and, under principles of cost causation, is necessarily reasonable.

In Case No. 2012-00152, the Commission stated its position with regard to gradualism related to cost shifting between classes:

"Gradualism requires the gradual shifting of costs between customer classes to the class of customer causing the cost. It is premised on the assumption that a utility will make periodic rate adjustments and the shift in costs can gradually be made during these periodic rate adjustments." See In the Matter of: Application of Big Sandy Water District for an Adjustment in Rates… Case No. 2012-00152 KY.P.S.C. March 08, 2013.

It is the Company's position that its proposed allocation of the overall revenue requirement in the cost of service is not an abrupt (or non-gradual) "shifting of costs between customer classes." As shown in Sailers' testimony Attachment BLS-2, the proposed Rate RS customer charge reflects the customer-related costs, allocable to residential customers, determined in the cost of service study.

Further, focusing on intra-class cost shifting, Company believes the 149% increase referenced in this request is not well focused and an inaccurate characterization. The only customer who would experience such a percentage increase on a total bill basis would be a customer who has zero usage each and every month. Even in such a circumstance, the no-usage customer would still only pay $11.22 per month under the Company's proposal, which is still lower than the other investor-owned fixed customer charges currently approved by the Commission in the Commonwealth of Kentucky. The Company suggests a more reasonable view of the percentage increase can be found in Schedule N which reviews the total increase in a customer's bill for various usage levels. Company believes that the Commission's position with regard to gradualism is applicable to the total residential bill and not an individual component of the bill. The residential customer bill (Rate RS) increase proposed for the residential customer using 1000 kWh per month is 17.1 percent.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-063

REQUEST:

Refer to the Sailers Testimony, page 11.

a. Provide a similar analysis to the average monthly bill under current and proposed rates for low-income and non-low-income customers.

b. Explain how Duke Kentucky identifies which of its customers are considered low-income customers for the purpose of calculating average annual usage.

RESPONSE:

a. The analysis provided in Sailers' Testimony on page 11 reflects low income and non-low income customers. The two usage levels noted on page 11 lines 20 and 21 represent the average usage for low and non-low income customers. The analysis requested is already provided with the results stated on page 12 lines 1 and 2.

b. Company uses data available from Acxiom in conjunction with federal government poverty guidelines to identify low-income customers.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-064

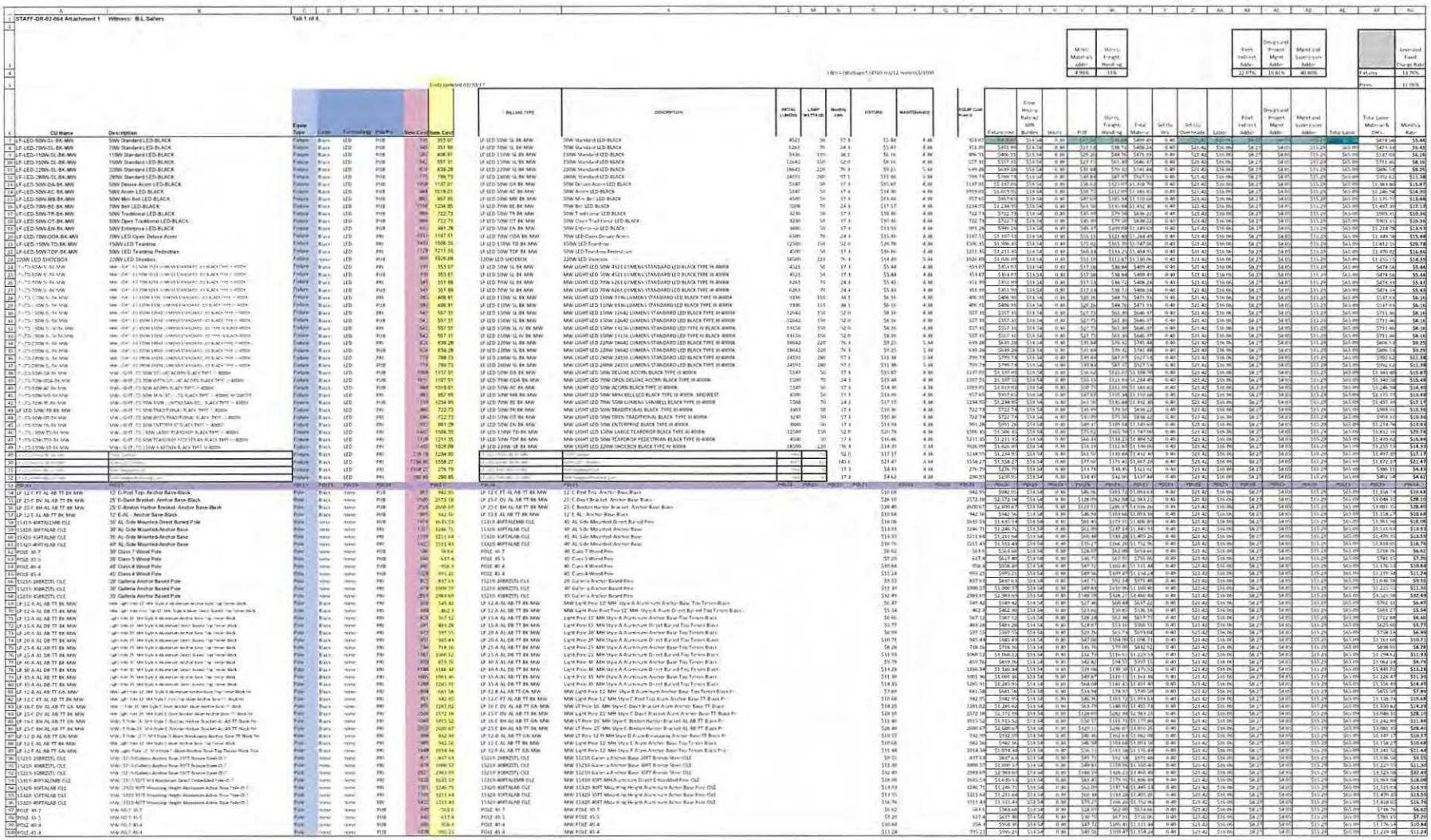
REQUEST:

Refer to the Sailers Testimony, page 13. Provide work papers and documentation supporting the proposed new LED street lighting tariff.

RESPONSE:

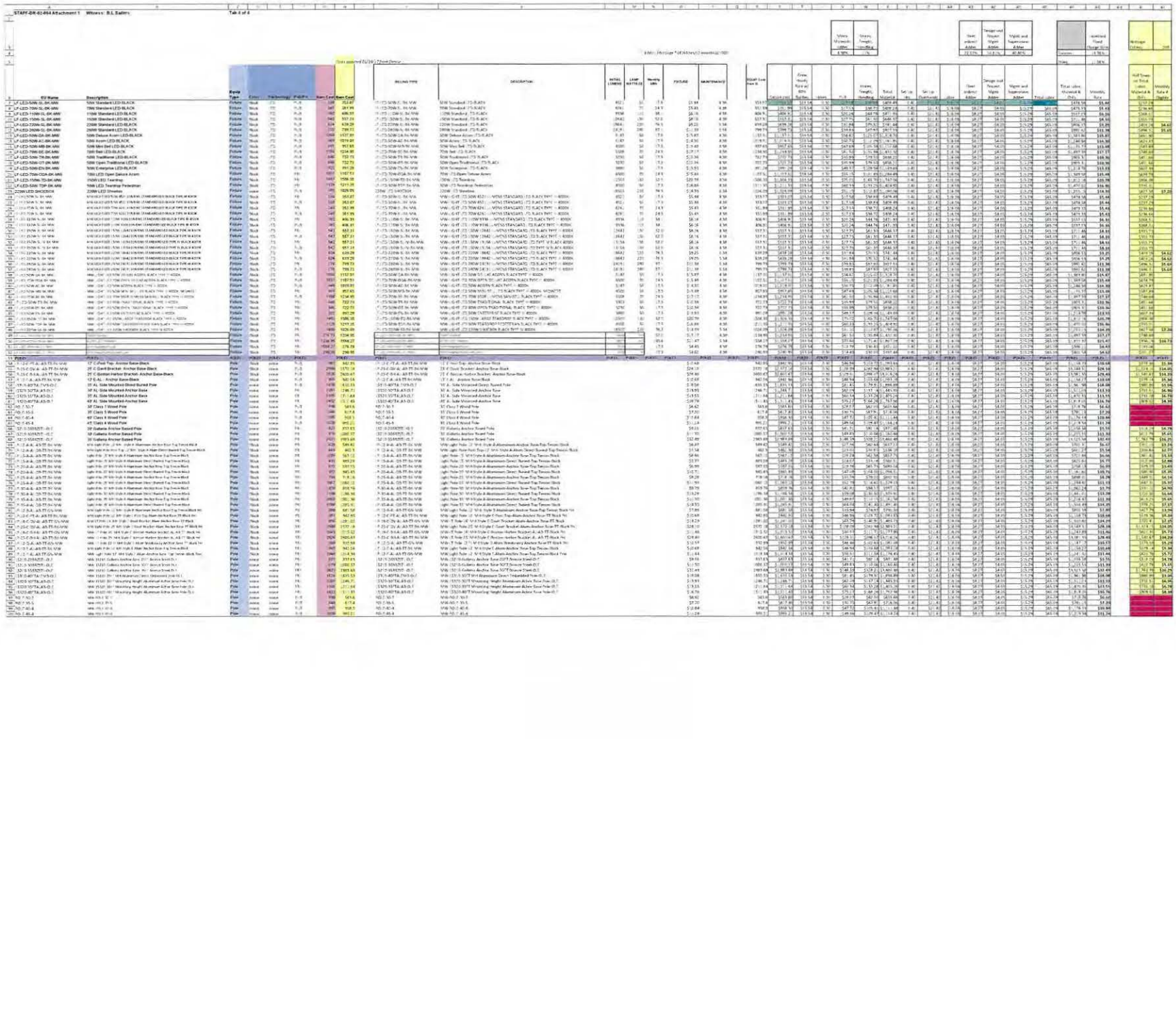
See Staff-DR-02-064 Attachment 1 (calculation of tariff sheet charges) and Staff-DR-02-064 Attachment 2 (calculation of LFCR, Levelized Fixed Charge Rate).

PERSON RESPONSIBLE: Bruce L. Sailers



	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1	STAFF-DR-02-064 Attachment 1	Witness: B.L.Sailers	Tab 2 of 4					Use these 3 columns to past into Word Doc						
2								IL Poles						
3	Paste values all columns from the Cus FROM ET FILE worksheet	Paste the columns from sheet "1. Cus FROM ET FILE"						Billing Type	Description	Charge per Month per Unit				
4	LP-12-C-PT-AL-AB-TT-BK-MW	12' C-Post Top- Anchor Base-Black				$ 10.68		LP-12-C-PT-AL-AB-TT-BK-MW	12' C-Post Top- Anchor Base-Black	$10.68				
5	LP-25-C-DV-AL-AB-TT-BK-MW	25' C-Davit Bracket- Anchor Base-Black				$ 28.10		LP-25-C-DV-AL-AB-TT-BK-MW	25' C-Davit Bracket- Anchor Base-Black	$28.10				
6	LP-25-C-BH-AL-AB-TT-BK-MW	25' C-Boston Harbor Bracket- Anchor Base-Black				$ 28.40		LP-25-C-BH-AL-AB-TT-BK-MW	25' C-Boston Harbor Bracket- Anchor Base-Black	$28.40				
7	LP-12-E-AL-AB-TT-BK-MW	12' E-AL - Anchor Base-Black				$ 10.68		LP-12-E-AL-AB-TT-BK-MW	12' E-AL - Anchor Base-Black	$10.68				
8	15310-40FTALEMB-OLE	35' AL-Side Mounted-Direct Buried Pole				$ 18.08		15310-40FTALEMB-OLE	35' AL-Side Mounted-Direct Buried Pole	$18.08				
9	15320-30FTALAB-OLE	30' AL-Side Mounted-Anchor Base				$ 13.93		15320-30FTALAB-OLE	30' AL-Side Mounted-Anchor Base	$13.93				
10	15320-35FTALAB-OLE	35' AL-Side Mounted-Anchor Base				$ 13.55		15320-35FTALAB-OLE	35' AL-Side Mounted-Anchor Base	$13.55				
11	15320-40FTALAB-OLE	40' AL-Side Mounted-Anchor Base				$ 16.76		15320-40FTALAB-OLE	40' AL-Side Mounted-Anchor Base	$16.76				
12	POLE-30-7	30' Class 7 Wood Pole				$ 6.62		POLE-30-7	30' Class 7 Wood Pole	$6.62				
13	POLE-35-5	35' Class 5 Wood Pole				$ 7.20		POLE-35-5	35' Class 5 Wood Pole	$7.20				
14	POLE-40-4	40' Class 4 Wood Pole				$ 10.84		POLE-40-4	40' Class 4 Wood Pole	$10.84				
15	POLE-45-4	45' Class 4 Wood Pole				$ 11.24		POLE-45-4	45' Class 4 Wood Pole	$11.24				
16	15210-20BRZSTL-OLE	20' Galleria Anchor Based Pole				$ 9.55		15210-20BRZSTL-OLE	20' Galleria Anchor Based Pole	$9.55				
17	15210-30BRZSTL-OLE	30' Galleria Anchor Based Pole				$ 11.30		15210-30BRZSTL-OLE	30' Galleria Anchor Based Pole	$11.30				
18	15210-35BRZSTL-OLE	35' Galleria Anchor Based Pole				$ 32.49		15210-35BRZSTL-OLE	35' Galleria Anchor Based Pole	$32.49				
19	LP-12-A-AL-AB-TT-BK-MW	MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black				$ 6.47		LP-12-A-AL-AB-TT-BK-MW	MW-Light Pole-12' MH- Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.47				
20	LP-12-A-AL-DB-TT-BK-MW	MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black				$ 5.54		LP-12-A-AL-DB-TT-BK-MW	MW-Light Pole-Post Top-12' MH- Style A-Alum-Direct Buried-Top Tenon-Black	$5.54				
21	LP-15-A-AL-AB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black				$ 6.66		LP-15-A-AL-AB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.66				
22	LP-15-A-AL-DB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black				$ 5.77		LP-15-A-AL-DB-TT-BK-MW	Light Pole-15' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$5.77				
23	LP-20-A-AL-AB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black				$ 6.99		LP-20-A-AL-AB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$6.99				
24	LP-20-A-AL-DB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black				$ 10.71		LP-20-A-AL-DB-TT-BK-MW	Light Pole-20' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$10.71				
25	LP-25-A-AL-AB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black				$ 8.28		LP-25-A-AL-AB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$8.28				
26	LP-25-A-AL-DB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black				$ 11.93		LP-25-A-AL-DB-TT-BK-MW	Light Pole-25' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$11.93				
27	LP-30-A-AL-AB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black				$ 9.79		LP-30-A-AL-AB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$9.79				
28	LP-30-A-AL-DB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black				$ 13.28		LP-30-A-AL-DB-TT-BK-MW	Light Pole-30' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$13.28				
29	LP-35-A-AL-AB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black				$ 11.30		LP-35-A-AL-AB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Anchor Base-Top Tenon-Black	$11.30				
30	LP-35-A-AL-DB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black				$ 14.35		LP-35-A-AL-DB-TT-BK-MW	Light Pole-35' MH-Style A-Aluminum-Direct Buried-Top Tenon-Black	$14.35				
31	LP-12-B-AL-AB-TT-GN-MW	MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri				$ 7.89		LP-12-B-AL-AB-TT-GN-MW	MW-Light Pole-12' MH- Style B Aluminum Anchor Base-Top Tenon Black Pri	$7.89				
32	LP-12-C-PT-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri				$ 10.68		LP-12-C-PT-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style C-Post Top-Alum-Anchor Base-TT-Black Pri	$10.68				
33	LP-16-C-DV-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black				$ 14.29		LP-16-C-DV-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black	$14.29				
34	LP-25-C-DV-AL-AB-TT-BK-MW	MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri				$ 28.10		LP-25-C-DV-AL-AB-TT-BK-MW	MW-Light Pole-25' MH-Style C-Davit Bracket-Alum-Anchor Base-TT-Black Pri	$28.10				
35	LP-16-C-BH-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri				$ 11.46		LP-16-C-BH-AL-AB-TT-GN-MW	MW-LT Pole-16' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$11.46				
36	LP-25-C-BH-AL-AB-TT-BK-MW	MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri				$ 28.40		LP-25-C-BH-AL-AB-TT-BK-MW	MW-LT Pole-25' MH-Style C-Boston Harbor Bracket-AL-AB-TT-Black Pri	$28.40				
37	LP-12-D-AL-AB-TT-GN-MW	MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri				$ 10.57		LP-12-D-AL-AB-TT-GN-MW	MW-LT Pole 12 Ft MH Style D Alum Breakaway Anchor Base TT Black Pri	$10.57				
38	LP-12-E-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black				$ 10.68		LP-12-E-AL-AB-TT-BK-MW	MW-Light Pole-12' MH-Style E-Alum-Anchor Base-Top Tenon-Black	$10.68				
39	LP-12-F-AL-AB-TT-GN-MW	MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie				$ 11.44		LP-12-F-AL-AB-TT-GN-MW	MW-Light Pole-12' MH-Style F-Alum-Anchor Base-Top Tenon-Black Prie	$11.44				
40	15210-20BRZSTL-OLE	MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE				$ 9.55		15210-20BRZSTL-OLE	MW-15210-Galleria Anchor Base-20FT Bronze Steel-OLE	$9.55				
41	15210-30BRZSTL-OLE	MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE				$ 11.30		15210-30BRZSTL-OLE	MW-15210-Galleria Anchor Base-30FT Bronze Steel-OLE	$11.30				
42	15210-35BRZSTL-OLE	MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE				$ 32.49		15210-35BRZSTL-OLE	MW-15210-Galleria Anchor Base-35FT Bronze Steel-OLE	$32.49				
43	15310-40FTALEMB-OLE	MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE				$ 18.08		15310-40FTALEMB-OLE	MW-15310-35FT MH Aluminum Direct Embedded Pole-OLE	$18.08				
44	15320-30FTALAB-OLE	MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE				$ 13.93		15320-30FTALAB-OLE	MW-15320-30FT Mounting Height Aluminum Achor Base Pole-OLE	$13.93				
45	15320-35FTALAB-OLE	MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE				$ 13.55		15320-35FTALAB-OLE	MW-15320-35FT Mounting Height Aluminum Achor Base Pole-OLE	$13.55				
46	15320-40FTALAB-OLE	MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE				$ 16.76		15320-40FTALAB-OLE	MW-15320-40FT Mounting Height Aluminum Achor Base Pole-OLE	$16.76				
47	POLE-30-7	MW-POLE-30-7				$ 6.62		POLE-30-7	MW-POLE-30-7	$6.62				
48	POLE-35-5	MW-POLE-35-5				$ 7.20		POLE-35-5	MW-POLE-35-5	$7.20				
49	POLE-40-4	MW-POLE-40-4				$ 10.84		POLE-40-4	MW-POLE-40-4	$10.84				
50	POLE-45-4	MW-POLE-45-4				$ 11.24		POLE-45-4	MW-POLE-45-4	$11.24				

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1	STAFF-DR-02-064 Attachment 1	Witness: B.L.Sailers	Tab 3 of 4						4. Fixtures					Per Unit Per Month	
2	BILLING TYPE	DESCRIPTION	INITIAL LUMENS	LAMP WATTAGE	Monthly kWh	FIXTURE	MAINTENANCE		Billing Type	Description	Initial Lumens	Lamp Wattage	Monthly kWh	Fixture	Maintenance
3	LF-LED-50W-SL-BK-MW	50W Standard LED-BLACK	4521	50	17.33	5.44	4.38		LF-LED-50W-SL-BK-MW	50W Standard LED-BLACK	4,521	50	17	$5.44	$4.38
4	LF-LED-70W-SL-BK-MW	70W Standard LED-BLACK	6261	70	24.27	5.43	4.38		LF-LED-70W-SL-BK-MW	70W Standard LED-BLACK	6,261	70	24	$5.43	$4.38
5	LF-LED-110W-SL-BK-MW	110W Standard LED-BLACK	9336	110	38.13	6.16	4.38		LF-LED-110W-SL-BK-MW	110W Standard LED-BLACK	9,336	110	38	$6.16	$4.38
6	LF-LED-150W-SL-BK-MW	150W Standard LED-BLACK	12642	150	52.00	8.16	4.38		LF-LED-150W-SL-BK-MW	150W Standard LED-BLACK	12,642	150	52	$8.16	$4.38
7	LF-LED-220W-SL-BK-MW	220W Standard LED-BLACK	18641	220	76.27	9.25	5.34		LF-LED-220W-SL-BK-MW	220W Standard LED-BLACK	18,641	220	76	$9.25	$5.34
8	LF-LED-280W-SL-BK-MW	280W Standard LED-BLACK	24191	280	97.07	11.38	5.34		LF-LED-280W-SL-BK-MW	280W Standard LED-BLACK	24,191	280	97	$11.38	$5.34
9	LF-LED-50W-DA-BK-MW	50W Deluxe Acorn LED-BLACK	5147	50	17.33	15.87	4.38		LF-LED-50W-DA-BK-MW	50W Deluxe Acorn LED-BLACK	5,147	50	17	$15.87	$4.38
10	LF-LED-50W-AC-BK-MW	50W Acorn LED-BLACK	5147	50	17.33	14.50	4.38		LF-LED-50W-AC-BK-MW	50W Acorn LED-BLACK	5,147	50	17	$14.30	$4.38
11	LF-LED-50W-MB-BK-MW	50W Mini Bell LED-BLACK	4500	50	17.33	13.48	4.38		LF-LED-50W-MB-BK-MW	50W Mini Bell LED-BLACK	4,500	50	17	$13.48	$4.38
12	LF-LED-70W-BE-BK-MW	70W Bell LED-BLACK	5508	70	24.27	17.17	4.38		LF-LED-70W-BE-BK-MW	70W Bell LED-BLACK	5,508	70	24	$17.17	$4.38
13	LF-LED-50W-TR-BK-MW	50W Traditional LED-BLACK	3230	50	17.33	10.36	4.38		LF-LED-50W-TR-BK-MW	50W Traditional LED-BLACK	3,230	50	17	$10.36	$4.38
14	LF-LED-50W-OT-BK-MW	50W Open Traditional LED-BLACK	3230	50	17.33	10.36	4.38		LF-LED-50W-OT-BK-MW	50W Open Traditional LED-BLACK	3,230	50	17	$10.36	$4.38
15	LF-LED-50W-EN-BK-MW	50W Enterprise LED-BLACK	3880	50	17.33	13.93	4.38		LF-LED-50W-EN-BK-MW	50W Enterprise LED-BLACK	3,880	50	17	$13.93	$4.38
16	LF-LED-70W-ODA-BK-MW	70W LED Open Deluxe Acorn	6500	70	24.27	15.48	4.38		LF-LED-70W-ODA-BK-MW	70W LED Open Deluxe Acorn	6,500	70	24	$15.48	$4.38
17	LF-LED-150W-TD-BK-MW	150W LED Teardrop	12500	150	52.00	20.78	4.38		LF-LED-150W-TD-BK-MW	150W LED Teardrop	12,500	150	52	$20.78	$4.38
18	LF-LED-50W-TDP-BK-MW	50W LED Teardrop Pedestrian	4500	50	17.33	16.86	4.38		LF-LED-50W-TDP-BK-MW	50W LED Teardrop Pedestrian	4,500	50	17	$16.86	$4.38
19	220W LED SHOEBOX	220W LED Shoebox	18500	220	76.27	14.39	5.34		220W LED SHOEBOX	220W LED Shoebox	18,500	220	76	$14.39	$5.34
20	LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4521	50	17.33	5.44	4.38		LF-LED-50W-SL-BK-MW	LED 50W 4521 LUMENS STANDARD LED BLACK TYPE III 4000K	4,521	50	17	$5.44	$4.38
21	LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6261	70	24.27	5.43	4.38		LF-LED-70W-SL-BK-MW	LED 70W 6261 LUMENS STANDARD LED BLACK TYPE III 4000K	6,261	70	24	$5.43	$4.38
22	LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9336	110	38.13	6.16	4.38		LF-LED-110W-SL-BK-MW	LED 110W 9336 LUMENS STANDARD LED BLACK TYPE III 4000K	9,336	110	38	$6.16	$4.38
23	LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12642	150	52.00	8.16	4.38		LF-LED-150W-SL-BK-MW	LED 150W 12642 LUMENS STANDARD LED BLACK TYPE III 4000K	12,642	150	52	$8.16	$4.38
24	LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13156	150	52.00	8.16	4.38		LF-LED-150W-SL-IV-BK-MW	LED 150W 13156 LUMENS STANDARD LED TYPE IV BLACK 4000K	13,156	150	52	$8.16	$4.38
25	LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18642	220	76.27	9.25	5.34		LF-LED-220W-SL-BK-MW	LED 220W 18642 LUMENS STANDARD LED BLACK TYPE III 4000K	18,642	220	76	$9.25	$5.34
26	LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24191	280	97.07	11.38	5.34		LF-LED-280W-SL-BK-MW	LED 280W 24191 LUMENS STANDARD LED BLACK TYPE III 4000K	24,191	280	97	$11.38	$5.34
27	LF-LED-50W-DA-BK-MW	LED 50W DELUXE ACORN BLACK TYPE III 4000K	5147	50	17.33	15.87	4.38		LF-LED-50W-DA-BK-MW	LED 50W DELUXE ACORN BLACK TYPE III 4000K	5,147	50	17	$15.87	$4.38
28	LF-LED-70W-ODA-BK-MW	LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	6500	70	24.27	15.48	4.38		LF-LED-70W-ODA-BK-MW	LED 70W OPEN DELUXE ACORN BLACK TYPE III 4000K	6,500	70	24	$15.48	$4.38
29	LF-LED-50W-AC-BK-MW	LED 50W ACORN BLACK TYPE III 4000K	5147	50	17.33	14.30	4.38		LF-LED-50W-AC-BK-MW	LED 50W ACORN BLACK TYPE III 4000K	5,147	50	17	$14.30	$4.38
30	LF-LED-50W-MB-BK-MW	LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	4500	50	17.33	13.48	4.38		LF-LED-50W-MB-BK-MW	LED 50W MINI BELL LED BLACK TYPE III 4000K MIDWEST	4,500	50	17	$13.48	$4.38
31	LF-LED-70W-BE-BK-MW	LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	5508	70	24.27	17.17	4.38		LF-LED-70W-BE-BK-MW	LED 70W 5508 LUMENS SANIBELL BLACK TYPE III 4000K	5,508	70	24	$17.17	$4.38
32	LF-LED-50W-TR-BK-MW	LED 50W TRADITIONAL BLACK TYPE III 4000K	3303	50	17.33	10.36	4.38		LF-LED-50W-TR-BK-MW	LED 50W TRADITIONAL BLACK TYPE III 4000K	3,303	50	17	$10.36	$4.38
33	LF-LED-50W-OT-BK-MW	LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	3230	50	17.33	10.36	4.38		LF-LED-50W-OT-BK-MW	LED 50W OPEN TRADITIONAL BLACK TYPE III 4000K	3,230	50	17	$10.36	$4.38
34	LF-LED-50W-EN-BK-MW	LED 50W ENTERPRISE BLACK TYPE III 4000K	3880	50	17.33	13.93	4.38		LF-LED-50W-EN-BK-MW	LED 50W ENTERPRISE BLACK TYPE III 4000K	3,880	50	17	$13.93	$4.38
35	LF-LED-150W-TD-BK-MW	LED 150W LARGE TEARDROP BLACK TYPE III 4000K	12500	150	52.00	20.78	4.38		LF-LED-150W-TD-BK-MW	LED 150W LARGE TEARDROP BLACK TYPE III 4000K	12,500	150	52	$20.78	$4.38
36	LF-LED-50W-TDP-BK-MW	LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	4500	50	17.33	16.86	4.38		LF-LED-50W-TDP-BK-MW	LED 50W TEARDROP PEDESTRIAN BLACK TYPE III 4000K	4,500	50	17	$16.86	$4.38
37	LF-LED-220W-SB-BK-MW	LED 220W SHOEBOX BLACK TYPE IV 4000K	18500	220	76.27	14.39	5.34		LF-LED-220W-SB-BK-MW	LED 220W SHOEBOX BLACK TYPE IV 4000K	18,500	220	76	$14.39	$5.34
38	LF-LED-150W-SE-BK-MW	150W Sanibel	39000	150	52.00	17.17	4.38		LF-LED-150W-SE-BK-MW	150W Sanibel	39,000	150	52	$17.17	$4.38
39	LF-LED-420W-SB-BK-MW	420W LED Shoebox	39078	420	145.60	21.47	5.34		LF-LED-420W-SB-BK-MW	420W LED Shoebox	39,078	420	146	$21.47	$5.34
40	LF-LED-50W-NB-GY-MW	50W Neighborhood	5000	50	17.33	4.43	4.38		LF-LED-50W-NB-GY-MW	50W Neighborhood	5,000	50	17	$4.43	$4.38
41	LF-LED-50W-NBL-GY-MW	50W Neighborhood with Lens	5000	50	17.33	4.62	4.38		LF-LED-50W-NBL-GY-MW	50W Neighborhood with Lens	5,000	50	17	$4.62	$4.38



DUKE ENERGY KENTUCKY, INC

Calculation of DEK's Levelized Fixed Charge Rate
For Lighting Plant With A 15 Year Life

LFCR Components				Proposed Capital Structure Rate of Return		
Rate	Symbol	Description		Cost Rate	Capital Ratio	Weighted Cost
7.21%	r	Rate of Return (Cost of Capital)	Long Term Debt	4.253%	46.750%	1.988%
6.67%	D	Depreciation Rate	Short Term Debt	2.062%	3.215%	0.066%
0.598%	A	Property Tax Rate	Preferred Stock	0.000%	0.000%	0.000%
0.011%	P	Property Insurance Rate	Common Equity	10.300%	50.035%	5.154%
38.474%	T	Federal and State Composite Income Tax Rate	ITC	0.000%	0.000%	
1.98%	i	Synchronized Interest Deduction	Deferred Taxes	0.000%	0.000%	
3.92%	d	Sinking Fund Depreciation Rate			100.000%	7.208%
0.000%	g	Commercial Activity Tax				
15	N	Service Life				

$$LFCR = \frac{1}{1-g}\left[(r + A + P + d) + \left(\frac{T}{1-T}\right)(r + d - D)\left(\frac{r-i}{r}\right)\right]$$

LFCR = **13.76%**

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-065

REQUEST:

Refer to the Sailers Testimony, page 16. Explain why Duke Kentucky is proposing to use a two-year average of PJM LMP prices for cogeneration facilities of 100 kW or less, and the PJM real-time price from cogeneration facilities of over 100 kW.

RESPONSE:

For cogeneration facilities of 100 kW or less, a standard contract offer is required. A two-year average PJM RT LMP is used for the longer-run avoided costs over the term.

For cogeneration facilities of over 100 kW, no standard offer contract is required. The PJM RT LMP represents the avoided energy cost at the time of delivery.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-066

REQUEST:

Refer to the Sailers Testimony, Attachment BLS-2.

a. Provide this table with the results from the Average and Excess Cost of Service Study ("COSS") results.

b. Provide this table with the results from the Summer/Non Summer COSS results.

RESPONSE:

a. The Average and Excess COSS does not change the customer component costs displayed in Attachment BLS-2. The table is unchanged.

b. The Summer/Non Summer COSS does not change the customer component costs displayed in Attachment BLS-2. The table is unchanged.

PERSON RESPONSIBLE: Bruce L. Sailers

REQUEST:

Refer to the Sailers Testimony, Attachment BLS-5.

a. Explain why it is reasonable to include Fleet costs in the calculation of the Remote Reconnection (AMI) charge.

b. Explain why it is reasonable to include Site Supervision: Engineering and setup in the calculation of the Remote Reconnection (AMI) charge.

c. Explain how the $33.27 amount shown for Base Labor was calculated.

d. Explain why Unproductive labor should be included in any of the charges shown.

e. Explain why Site Supervision and Setup are included in the charges for any reconnection made by a single person crew.

RESPONSE:

a. The reconnection charge tariff sheet separates the charge for a remote reconnection compared to a non-remote (i.e., on-site) reconnection. The loaded average labor rate for field operations personnel is used as the cost proxy for both remote and non-remote reconnection. This is similar to remote reconnection charge calculations used in other Duke Energy service areas such as Duke Energy Ohio. This approach provides for a consistent calculation of reconnection charges and eases administration of reconnections. Related information is included in AG-DR-01-082 where Company states that the Company is amenable to consider

using an alternative labor rate reflecting call center resources that handle reconnection calls for remote reconnection charge calculations. But Company further notes that the Company's total revenue requirement includes the proposed reconnection charges. To the extent a different and lower reconnection charge is approved by the Commission, the Company's revenue requirement must also be adjusted.

b. See response to Staff-DR-02-067 (a) above.

c. Base Labor is the average pay rate for employee classifications typically performing the work. It represents "worked" time only. See response to AG-DR-01-082 for additional details.

d. Unproductive labor cost is the cost of paid time away from work such as vacations, sick, and holidays. It's included because both the Base Labor and Unproductive combined represent the employee's salary rate.

e. Site Supervision is zero and is not part of the calculation. Setup represents the time to drive to and from the site in addition to any safety or site preparation time.

PERSON RESPONSIBLE: Bruce L. Sailers

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-068

REQUEST:

Refer to the Silinski Testimony, page 4. Provide the annual rate of turnover or retention rate for years 2012-2016.

RESPONSE:

Below is the annual turnover rate for years 2012-2016 for Duke Energy Kentucky and Duke Energy Business Services.

Year	Duke Energy Kentucky	Duke Energy Business Services
2012	6.7%	8.4%
2013	10.9%	7.2%
2014	7.1%	5.7%
2015	8.0%	6.4%
2016	10.1%	8.9%

PERSON RESPONSIBLE: Tom Silinski

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-069

REQUEST:

Refer to the Silinski Testimony beginning at page 18 and Duke Kentucky's response to Staff's First Request, Item 66. Provide the following information:

a. The amount of incentive pay by each incentive pay program based upon earnings per share for Duke Kentucky for the test period.

b. The amount of incentive pay allocated to Duke Kentucky by incentive pay program based upon earnings per share for its affiliated companies for the test period.

RESPONSE:

Please refer to the following attachment, STAFF-DR-02-069 Attachment 1.

PERSON RESPONSIBLE: Tom Silinski

Incentive Compensation: Short-term Incentive (STI)

Response:

Total budgeted incentive Apr - Dec 2018

Measure	Weight	DE Kentucky	Affiliates: DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
Total Incentive	0%	$ 1,336,765	$ 205,121	$ 2,562,971	$ 68,926	$ 71,426	$ 38,994	$ 8,021	$ 119,394	$ 4,411,617
Non-Union		$ 1,045,389	$ 205,121	$ 2,517,703	$ 58,310	$ 71,426	$ 38,994	$ 8,021	$ 119,394	$ 4,064,356
Union		291,376	-	45,268	10,616	-	-	-	-	347,261
Total		$ 1,336,765	$ 205,121	$ 2,562,971	$ 68,926	$ 71,426	$ 38,994	$ 8,021	$ 119,394	$ 4,411,617
Earnings Per Share (EPS)										
Non-Union	30%	313,617	61,536	755,311	17,493	21,428	11,698	2,406	35,818	$ 1,219,307
Union	19%	53,958	-	8,383	1,966	-	-	-	-	64,307
Total		$ 367,574	$ 61,536	$ 763,694	$ 19,459	$ 21,428	$ 11,698	$ 2,406	$ 35,818	$ 1,283,614

Total budgeted incentive Jan - Mar 2019

Measure	Weight	DE Kentucky	Affiliates: DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
Total	0%	$ 434,254	$ 69,042	$ 847,667	$ 19,991	$ 23,128	$ 13,305	$ 6,504	$ -	$ 1,413,890
Non-Union		$ 334,621	$ 69,042	$ 832,521	$ 17,091	$ 23,128	$ 13,305	$ 6,504	$ -	$ 1,296,211
Union		99,633	-	15,147	2,900	-	-	-	-	117,679
Total		$ 434,254	$ 69,042	$ 847,667	$ 19,991	$ 23,128	$ 13,305	$ 6,504	$ -	$ 1,413,890
Earnings Per Share (EPS)										
Non-Union	30%	100,386	20,713	249,756	5,127	6,938	3,991	1,951	-	$ 388,863
Union	19%	18,450	-	2,805	537	-	-	-	-	21,792
Total		$ 118,837	$ 20,713	$ 252,561	$ 5,664	$ 6,938	$ 3,991	$ 1,951	$ -	$ 410,655

Incentive Compensation: Long-term Incentive (LTI)

Response:

Total budgeted incentive Apr 2018 - Mar 2019

		Affiliates							
Measure	DE Kentucky	DE Carolinas	Service Company	DE Ohio	DE Indiana	DE Progress	DE Florida	Piedmont	Total to DE Kentucky
Restricted Stock Units	$ -	$ -	$ 1,023,228	$ -	$ -	$ -	$ -	$ -	$ 1,023,228
Performance Shares	-		508,980						508,980
Total Incentive - LTI	$ -	$ -	$ 1,532,208	$ -	$ -	$ -	$ -	$ -	$ 1,532,208

Earnings Per Share (EPS) $ 226,589

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-070

REQUEST:

Refer to the Direct Testimony of John L. Sullivan, III ("Sullivan Testimony"), pages 11-12.

a. Provide Bloomberg's Implied forward curve for the one-month London Interbank Offered Rate ("LIBOR") as of July 2017 and the most current.

b. Explain why a 75-basis-point credit spread was added to the LIBOR rate for the base and forecast period short-term interest rate.

c. Explain why a 25-basis-point credit spread was added to the LIBOR rate for the base and forecast period long-term interest rate.

RESPONSE:

a. Below is the forward curve through March 2019 as of the two periods requested. The information was pulled from Bloomberg.

%	July 2017	October 2017
Aug. 2017	1.2270%	
Sep. 2017	1.2319	
Oct. 2017	1.2417	
Nov. 2017	1.2596	1.2984%
Dec. 2017	1.3045	1.3466
Jan. 2018	1.3613	1.4335
Feb. 2018	1.4020	1.5155
Mar. 2018	1.4295	1.5690
April 2018	1.4485	1.5814
May 2018	1.4512	1.5660
June 2018	1.4732	1.6103
July 2018	1.4960	1.6527
Aug. 2018	1.5286	1.6979

Sep. 2018	1.5497	1.7242
Oct. 2018	1.5698	1.7440
Nov. 2018	1.5986	1.7603
Dec. 2018	1.6332	1.7875
Jan. 2019	1.6628	1.8156
Feb. 2019	1.6670	1.8420
Mar. 2019	1.6737%	1.8659%

b. The 75-basis-point credit spread used for the Sale of Accounts Receivables includes an estimate of: (a) the credit spread on the Sale of Accounts Receivables financing, and, (b) incremental interest over 1 month LIBOR that the participating banks charge (which is generally 10-12 basis points above 1 month LIBOR).

The credit spread on the current Sale of Accounts Receivables agreement is 67.5 basis points. This spread is expected to increase to 72.5 basis points when the facility is renewed in late November, or early December. The aforementioned 10-12 basis points are in addition to this credit spread.

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

	Weighted average Commercial Paper Rate	1 Month LIBOR	Excess of Commercial Paper Rate over 1 Month LIBOR
6/30/2017	1.43%	1.22%	0.21%
9/29/2017	1.43%	1.23%	0.20%
10/30/2017	1.44%	1.24%	0.20%

PERSON RESPONSIBLE: Jack Sullivan

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 2, 2017

STAFF-DR-02-071

REQUEST:

Refer to the Sullivan Testimony, page 12. Explain whether there has been any change in the estimated interest rate for the October 2018 long-term debt issuance of $70 million.

RESPONSE:

There has been no change.

PERSON RESPONSIBLE: Jack Sullivan

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-072

REQUEST:

Refer to the Sullivan Testimony, page 13. Provide an itemized list of what is included in the $505 million projected capital expenditures.

RESPONSE:

Please see STAFF-DR-02-072 Attachment.

PERSON RESPONSIBLE: Robert H. Pratt

$000s

Line No.	FERC Function	Project Class	Projected CapEx
1	Common - General Plant	Unspecified	(15,000)
2	Common - Intangible Plant	Unspecified	4,142
3	Elec - Distribution Plant	FF - Transmission Stations	6,984
4	Elec - Distribution Plant	GG - Transmission Lines	8
5	Elec - Distribution Plant	HA - Distribution Substation Lots	2,285
6	Elec - Distribution Plant	HB - Distribution Substation	3,481
7	Elec - Distribution Plant	IK - Distrib Lines OH/UG (Line Ext)	39,731
8	Elec - Distribution Plant	IK - Other - Distrib Lines OH/UG (Line Ext)	23,434
9	Elec - Distribution Plant	IL - Street Lights	8
10	Elec - Distribution Plant	IO - Distribution Improvements	32,583
11	Elec - Distribution Plant	TA - Other - Gen BLDG/Land/Furniture	929
12	Elec - Distribution Plant	TB - Equipment & Tools	276
13	Elec - Distribution Plant	TD - Office Equipment	5,479
14	Elec - General Plant	IO - Distribution Improvements	721
15	Elec - General Plant	RR - Communication	120
16	Elec - General Plant	SA - Gen. Bldg. & Oper. Centers	6,831
17	Elec - General Plant	TD - Other - Office Equipment	141
18	Elec - Intangible Plant	VS - Cust - Intangible Plant - Software	82
19	Elec - Intangible Plant	VS - Intangible Plant - Software	9,050
20	Elec - Other Production Plant	BY - Solar Energy Production	14,500
21	Elec - Other Production Plant	RR - Communication	660
22	Elec - Steam Production Plant	B1 - Fossil Env Compliance Air	39,875
23	Elec - Steam Production Plant	B4 - Fossil Ash Basin Initiative	92,164
24	Elec - Steam Production Plant	BA - Fossil Steam Plants	37,727
25	Elec - Steam Production Plant	BD - Environmental Fossil Plants	264
26	Elec - Steam Production Plant	BG - Other Production Plant	75,432
27	Elec - Transmission Plant	FF - Transmission Stations	11,210
28	Elec - Transmission Plant	GG - Transmission Lines	5,526
29	Gas - Distribution Plant	TD - Office Equipment	669
30	Gas - Distribution Plant	ZG - Gas Special Projects	24,410
31	Gas - Distribution Plant	ZH - Gas Distribution	58,620
32	Gas - Distribution Plant	ZK - Gas Meters	6,798
33	Gas - General Plant	TD - Other - Office Equipment	76
34	Gas - General Plant	ZH - Gas Distribution	12,094
35	Gas - General Plant	ZI - Gas Building & Grounds	571
36	Gas - Intangible Plant	VS - Intangible Plant - Software	2,826
			504,706

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-073

REQUEST:

Refer to the Direct Testimony of John D. Swez ("Swez Testimony"), pages 19-20. Provide the effect on the FAC of the proposed billing line items for October 2016 – September 2017 and the filed FAC.

RESPONSE:

See Staff-DR-02-073 Attachment for the effect of the proposed billing line items for October 2016- September 2017 on the filed FAC.

If the Commission doesn't approve the proposed inclusion of these billing line items in the FAC, these forecasted amounts would need to be included in the test year revenue requirement for base rates.

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky, Inc.
Effect on the FAC of Including
Net Fuel Related RTO Billing Line Items

KyPSC Case No. 2017-00321
STAFF-DR-01-073 Attachment

Description	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
Net Fuel Related RTO Billing Line Items	180,322	204,196	246,270	287,127	80,657	269,912	146,363	128,192	196,192	215,050	266,459	743,814
Sales S_m (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	353,538,927	391,174,764	373,168,291	317,739,674
Effect on the FAC	0.0601	0.0707	0.0707	0.0843	0.0281	0.0851	0.0516	0.0410	0.0555	0.0550	0.0714	0.2341

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 2, 2017

STAFF-DR-02-074

REQUEST:

Refer to the Swez Testimony, page 26.

a. Quantify and explain in detail what the proposed changes to Rider PSM will have on any revenue or expense in comparison to the existing Rider PSM.

b. Identify and explain what impacts Duke Kentucky's proposed Federal Energy Regulatory Commission Transmission Cost Reconciliation Rider will have on Rider PSM.

c. Explain Duke Kentucky's position regarding the proposed Rider FTR and the transfer of risk from the company's shareholders to its customers.

RESPONSE:

a. Please see Staff-DR-02-079 Attachment for the impact of the proposed changes to the revenue and expense in the existing Rider PSM for the periods 2015, 2016, and year-to-date September 2017.

b. Duke Energy Kentucky's proposed Rider FTR will not have any impact on Rider PSM.

c. The transmission expenses incurred are pursuant to FERC-approved rates and are necessary to serve Duke Energy Kentucky's customers. The Company denies that it is transferring any risk inasmuch as FERC-approved transmission rates are recoverable. The only risk that occurs with base rate recovery is whether the

Company over recovers or under recovers from year to year. By placing these costs into a discrete rider ensures that customers are paying no more and no less than the actual costs incurred to serve them.

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-075

REQUEST:

Refer to the Direct Testimony of John A. Verderame ("Verderame Testimony"), page 5.

a. Provide the Duke Energy Kentucky PJM load forecast.

b. Explain any differences between this forecast and the internal load forecast used in the instant case.

RESPONSE:

a.

Load Forecast Comparison

	Duke's Forecast			*PJMS PLC*		
	Duke Native	**EKPC Load**	**Total**	**Duke Native**	**EKPC**	**Total**
2017	845	21.2	866.2	822.6	19.2	841.8
2018	842	21.5	863.5	859.4	20.5	879.9
2019	843	21.7	864.7	802.1	18.6	820.7
2020	843	21.8	864.8	822.6	19.2	841.8

b. The table above includes Duke Energy Kentucky's latest internal load forecasts as of the filing of the instant case and the PJM determined load forecasts calculated at either the time of the Base Residual Auction (BRA) for the relevant Delivery Year (2018 through 2020), or in the case of 2017 the PJM Final load forecast completed just prior to the Delivery Year. The Final Load Forecast at the Delivery Year represents the basis for the obligation that Duke Energy Kentucky must meet during that year in its Final FRR Plan. While different models can be expected to return different results, explicit

differences between the two forecasts in the table are driven by timing and component factors. PJM provides a load forecast at the time of the BRA which is three years prior to the actual Deliver Year while the Duke forecast is updated regularly. Additionally, the Duke forecast included in the instant case did not represent the load forecast for load served through East Kentucky Power Cooperative's Longbranch substation.

PERSON RESPONSIBLE: John Verderame

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-076

REQUEST:

Refer to the Verderame Testimony, page 13.

a. Describe in detail the differences in the capacity values listed for locational delivery areas, general clearing price, and the Duke Energy Ohio Kentucky total clearing price.

b. Describe in detail the major factors considered in determining whether to operate in PJM under the Reliability Pricing Model ("RPM") construct or the FRR construct.

c. Describe in detail the impact of the Capacity Performance construct will have on Duke Kentucky in determining whether to operate in PJM under the RPM construct or the FRR construct when fully implemented in the 2020/2021 Delivery Year.

d. Identify and describe any limitations in PJM on Duke Kentucky for changing its participation from the FRR construct to the RPM construct.

RESPONSE:

a. The PJM footprint includes several sub regions, including the DEOK zone, which encompasses the Duke Energy Kentucky service territory. In the PJM capacity market clearing construct, if the marginal MW of capacity needed to meet a sub region reliability requirement can be provided by generation in the sub region, or

from outside the sub region without causing a binding transmission constraint, the sub region will clear as part of the broad footprint market If the sub region reliability requirement cannot be met, the sub region separates from the broader capacity region and PJM clears the shortfall of capacity with generation offers from within the sub region. In the 2020/2021 Base Residual Auction, four of these sub regions cleared at prices differing from the regional price. Please see STAFF-DR-02-076a ATTACHMENT where PJM describes the details behind the auction clearing results including the zonal separation of the DEOK zone. The original document is available here:

http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx

b. As an FRR entity, Duke Energy Kentucky must secure and commit unit-specific generation resources to meet the peak load capacity requirements for all of its customers in advance of the PJM's annual BRA through its FRR Plan. Duke Energy Kentucky's review of its participation status as a PJM member is both periodic and ongoing. From a periodic perspective, Duke Energy Kentucky can only change status at the beginning of the Planning Year in which it has not already submitted an FRR plan. This is because capacity procurement for the BRA and incremental auctions occur three years in advance of the Delivery Year and would have already been procured and committed in the RPM. Thus, in order to effectuate such a change, a decision must be made in the Planning Year three years in advance of the Delivery Year through which the Company would actually procure capacity, so that it could participate in the applicable BRA.

Duke Energy Kentucky intends to remain an FRR entity until it can prove to the Commission that there is sufficient customer benefit in moving to RPM. From an ongoing perspective, Duke Energy Kentucky is always watchful for signposts that the benefits of joining RPM outweigh potential risks. There are both pros and cons to full participation in RPM. To date the Company believes that customers are, on balance, better off remaining under the self-supply/FRR option.

The key driver behind the ongoing decision to remain FRR or move to RPM will likely remain Duke Energy Kentucky's net generation position, the difference between generation available to serve as PJM capacity and the expected customer load obligation. For Duke Energy Kentucky, the primary benefit to customers from owned-generation is its use as a hedge against capacity and energy market prices. Additionally, the ability to utilize the market as a resource and to monetize the value of customer generation assets is a key benefit of participation in a market like PJM. Currently, the Company believes that near term net position to remain relatively flat. In other words, Duke Energy Kentucky does not expect to be a significant buyer or seller of capacity in the market; and when it does need to transact in the market for capacity outside of RPM the Company has found that there is adequate liquidity in that bilateral market for current needs.

As the Company considers the future of the generation assets however, the net capacity position may move away from that relatively neutral position, forcing the Company to reevaluate its participation.

When Duke Energy Kentucky last retired a generating asset, Miami Fort 6, it was able to economically replace it with a similar amount of generation. If the opportunity or need to retire or replace another asset's capacity were to arise, it is possible that it would be beneficial to procure or sell capacity directly from or to the PJM (RPM) capacity market for some time, either from a long or short perspective. If that were the case, and the Company did not feel that it could efficiently cover or monetize the position in the bilateral market, there could be an argument supporting a move to RPM.

While the deep liquidity of RPM is a benefit to full RPM participation, a moderate long position would not necessarily prompt an immediate status change. Duke Energy Kentucky remains watchful for indications of potential changes in PJM market rules that could have significant impacts on its customers. One of the more contentious market rules in PJM is the Minimum Offer Price Rule (MOPR). Currently, generation included in FRR Plans is not subject to the MOPR. The MOPR sets administratively defined generation class capacity market price floors for gas fired generation that has never cleared in an auction. The impact on generation owners that are not exempt from the rule is an increased risk that generation investments do not clear capacity auctions. The direct impact of changes to the MOPR rule, current exemptions, and applicability to Duke Energy Kentucky would be the potential impact on investment decisions as Duke Energy Kentucky's load grows beyond its current generation capacity, or current generation resources either reach the end of their useful lives or become economically obsolete due to environmental regulation. While currently exempt

from the MOPR under the Self-Supply exemption, if Duke Energy Kentucky and the Kentucky Public Service Commission determined a move to full participation in RPM would be beneficial to customers, either the elimination of that exemption, or the expansion of the MOPR to existing resources could expose Duke Energy Kentucky customers to the risk of paying twice for newly constructed or existing capacity, once through rates and again through a capacity allocation from PJM.

c. From a practical perspective both FRR and RPM entities are subject to the same obligations and risks; but without a compelling external driver, the introduction of Capacity Performance does not currently significantly impact the decision to more to full RPM participation. In fact, Duke Energy Kentucky has benefited so far from remaining an FRR entity. During the Capacity Performance approval process, in the PJM stakeholder forum and before the Federal Energy Regulatory Commission, Duke Energy Kentucky argued that FRR entities should be exempted entirely from Capacity Performance requirements. Ultimately the final FERC order approving Capacity Performance included some concessions to FRR entities primarily regarding the timing of full compliance with Capacity Performance, and Duke Energy Kentucky was able to postpone compliance with Capacity Performance requirements through the 2018/2019 Delivery year. Going forward, PJM has also instituted an FRR-only option of meeting compliance assessments through the addition of physical generation into subsequent FRR Plans. This option may prove to be an economically viable alternative; and the Company will continue to evaluate such risk mitigation strategies for customers.

As Capacity Performance matures as a construct the Company will be watchful however for changes in bilateral market activity, particularly market liquidity changes in response to the Capacity Performance construct. One possible implication of Capacity Performance could be counterparty limitations driven by dramatically increased financial implications of contractual non-performance tied to PJM performance assessment risk. If Duke Energy Kentucky anticipates a need to purchase short term capacity and sees signs of an inability to find acceptable bilateral terms and conditions, the current calculus may change.

At this time, however, the Company does not consider a strategy including a move to full PJM auction participation to be a least cost mitigation for Duke Energy Kentucky customers to address Capacity Performance risks.

d. Other than the timing restrictions noted above, specifically that Duke Energy Kentucky could only move to full RPM participation at the beginning of the Delivery Year Planning cycle, roughly three years prior to a Delivery Year, Duke Energy Kentucky does not anticipate that there would be any limitations imposed by PJM. The decision remains a strategic one, based in the balanced best interests of our customers.

Duke Energy Kentucky's participation in the RPM as an FRR entity is consistent with the Commission's Order in Case No. 2010-00203 whereby the Commission required the Company to participate in PJM as an FRR entity until such time as it received Commission approval to participate in the PJM capacity auctions. To date, Duke Energy Kentucky has not requested such permission, but

will do so if the Company determines that a change would be in the best interests of its customers and should be made.

PERSON RESPONSIBLE: John Verderame

2020/2021 RPM Base Residual Auction Results

Executive Summary

The 2020/2021 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. Accounting for load and resource commitments under the Fixed Resource Requirement (FRR), the reserve margin for the entire RTO for the 2020/2021 Delivery Year as procured in the BRA is 23.3%, or 6.7% higher than the target reserve margin of 16.6%. This reserve margin was achieved at clearing prices that are between approximately 26% to 66% of Net CONE, depending upon the Locational Deliverability Area (LDA), while attracting 2,350 MW of new combined cycle gas resources.

The 2020/2021 BRA is the first where PJM has procured 100% Capacity Performance ("CP") Resources. CP Resources must be capable of sustained, predictable operation, and are expected to be available and capable of providing energy and reserves when needed throughout the entire Delivery Year. Also, the 2020/2021 BRA was conducted under the provisions of PJM's Enhanced Aggregation filing (Docket ER17-367-000 & 001) which was accepted by FERC on March 21, 2017.

2020/2021 BRA Resource Clearing Prices

Resource Clearing Prices (RCPs) for the 2020/2021 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $76.53/MW-day. The MAAC LDA, EMAAC LDA, ComEd LDA and DEOK LDA were constrained LDAs in the 2020/2021 BRA with locational price adders of $9.51/MW-day, $101.83/MW-day, $111.59/MW-day and $53.47/MW-day, respectively, for all resources located in those LDAs. For comparison purposes, the RCP for CP Resources located in the rest of RTO and MAAC in the 2019/2020 BRA was $100.00/MW-day. For the same year, the RCP for CP Resources in the EMAAC LDA was $119.77/MW-day and the RCP for CP Resources in the COMED LDA was $202.77 /MW-day in the 2019/2020 BRA. The DEOK LDA was not modeled in the 2019/20 BRA and cleared with the rest of RTO.

	2020/2021 BRA Resource Clearing Prices ($/MW-day)				
Capacity Type	Rest of RTO	MAAC	EMAAC	COMED	DEOK
Capacity Performance	$76.53	$86.04	$187.87	$188.12	$130.00

2020/2021 RPM Base Residual Auction Results

2020/2021 BRA Cleared Capacity Resources

As seen in the table below, the 2020/2021 BRA procured 2,389.3 MW of capacity from new generation and 434.5 MW from uprates to existing or planned generation. The quantity of capacity procured from external Generation Capacity Resources in the 2020/2021 BRA is 3,997.2 MW which is an increase of 121.3 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2020/21 BRA has the requirements for the Capacity Import Limit (CIL) exception which include (1) long-term firm transmission service has been confirmed on the complete transmission path from the external resource into PJM for the relevant Delivery Year; (2) the external resource meets or will meet prior to the Delivery Year all applicable requirements to be pseudo-tied; and (3) a separate written commitment has been executed to offer all unforced capacity of the external resource into RPM Auctions under the same terms, and subject to the same conditions and exceptions, as set forth for internal generation resources by section 6.6 of Attachment DD of PJM Tariff. The total quantity of DR procured in the 2020/2021 BRA is 7,820.4 MW which is a decrease of 2,527.6 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2020/2021 BRA is 1,710.2 MW, which is an increase of 195.1 MW from that procured in last year's BRA.

Megawatts of Unforced Capacity Procured by Type from the 2014/2015 BRA to the 2020/2021 BRA

Delivery Year	New Generation	Generation Uprates	Imports	Demand Response	Energy Efficiency
2020/2021	2,389.3	434.5	3,997.2	7,820.4	1,710.2
2019/2020	5,373.6	155.6	3,875.9	10,348.0	1,515.1
2018/2019	2,954.3	587.6	4,687.9	11,084.4	1,246.5
2017/2018	5,927.4	339.9	4,525.5	10,974.8	1,338.9
2016/2017	4,281.6	1,181.3	7,482.7	12,408.1	1,117.3
2015/2016	4,898.9	447.4	3,935.3	14,832.8	922.5
2014/2015	415.5	341.1	3,016.5	14,118.4	822.1

*All MW Values are in UCAP Terms

2020/2021 RPM Base Residual Auction Results

Introduction

This document provides information for PJM stakeholders regarding the results of the 2020/2021 Reliability Pricing Model (RPM) Base Residual Auction (BRA). The 2020/2021 BRA opened on May 10, 2017, and the results were posted on May 23, 2017.

In each BRA, PJM seeks to procure a target capacity reserve level for the RTO in a least cost manner while recognizing the following reliability-based constraints on the location and type of capacity that can be committed:

- Internal PJM locational constraints are established by setting up Locational Deliverability Areas (LDAs) with each LDA having a separate target capacity reserve level and a maximum limit on the amount of capacity that it can import from resources located outside of the LDA.
- Total cleared summer-period sell offers must exactly equal total cleared winter-period sell offers across the entire RTO to ensure that seasonal CP sell offers clear to form annual CP commitments.

The auction clearing process commits capacity resources to procure a target capacity reserve level for the RTO in a least-cost manner while recognizing and enforcing these reliability-based constraints. The clearing solution may be required to commit capacity resources out-of-merit order but again in a least-cost manner to ensure that all of these constraints are respected. In those cases where one or more of the constraints results in out-of-merit commitment in the auction solution, resource clearing prices will be reflective of the price of resources selected out of merit order to meet the necessary requirements.

This document begins with a high-level summary of the BRA results followed by sections containing detailed descriptions of the 2020/2021 BRA results and a discussion of the results in the context of the ten previous BRAs.

Summary of Results

The 2020/2021 Reliability Pricing Model (RPM) Base Residual Auction (BRA) cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. The reserve margin for the entire RTO is 23.3%, or 6.7% higher than the target reserve margin of 16.6%, when the Fixed Resource Requirement (FRR) load and resources are considered.

Resource Clearing Prices (RCPs) for the 2020/2021 BRA are shown in Table 1 below. The RCP for CP Resources located in the rest of RTO is $76.53/MW-day. The MAAC LDA, EMAAC LDA, ComEd LDA and DEOK LDA were constrained LDAs in the 2020/2021 BRA with locational price adders of $9.51/MW-day, $101.83/MW-day, $111.59/MW-day and $53.47/MW-day, respectively, for all resources located in those LDAs. For comparison purposes, the RCP for CP Resources located in the rest of RTO

2020/2021 RPM Base Residual Auction Results

and MAAC in the 2019/2020 BRA was $100.00/MW-day. The RCP for CP Resources in the EMAAC LDA was $119.77/MW-day and the RCP for CP Resources in the COMED LDA was $202.77 /MW-day in the 2019/2020 BRA. The DEOK LDA was not modeled in the 2019/20 BRA and cleared at the RTO RCP.

The total quantity of new Generation Capacity Resources offered into the auction was 3,143.5 MW (UCAP) comprised of 2,536.6 MW (UCAP) of new generation units and 606.9 MW (UCAP) of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 2,823.8 MW (UCAP) comprised of 2,389.3 MW (UCAP) from new generation units and 434.5 MW from uprates to existing generation units.

The quantity of capacity procured from external Generation Capacity Resources in the 2020/2021 BRA is 3,997.2 MW which is an increase of 121.3 MW from that procured in last year's BRA. All external generation capacity that has cleared in the 2020/2021 BRA has met the requirements for a CIL exception. These requirements help to ensure that external resources offering into the RPM auction have reasonable expectation of physically delivering on any RPM commitment and have high likelihood of being available for PJM when needed.

The total quantity of DR procured in the 2020/2021 BRA is 7,820.4 MW which is a decrease of 2,527.6 MW from that procured in last year's BRA; and, the total quantity of EE procured in the 2020/2021 BRA is 1,710.2 MW which is an increase of 195.1 MW from that procured in last year's BRA.

The RTO as a whole failed the Market Structure Test (i.e., the Three-Pivotal Supplier Test), resulting in the application of market power mitigation to all existing generation resources. Mitigation was applied to a supplier's existing generation resources resulting in utilizing the lesser of the supplier's approved Market Seller Offer Cap for such resource or the supplier's submitted offer price for such resource in the RPM Auction clearing.

2020/2021 RPM Base Residual Auction Results

All Generation Capacity Resources (including uprates to existing resources) of 20 MW or greater that are based on combustion turbine, combined cycle and integrated gasification combined cycle technologies that have not cleared an RPM Auction prior to February 1, 2013 are subject to the Minimum Offer Price Rule (MOPR). External Generation Capacity Resources meeting the above criteria and that have entered commercial operation on or after January 1, 2013 and that require sufficient transmission investment for delivery into PJM are also subject to MOPR. To avoid application of the MOPR, Capacity Market Sellers may request exemption through either a Competitive Entry Exemption request, Self-Supply Exemption request or a Unit-Specific Exemption request. The table below shows the requested, granted and cleared aggregate quantity (in ICAP MW) of each exemption type received and processed by PJM. While there were over 12,000 MW of MOPR exemption requests, making a request does not obligate a resource to offer into the BRA.

LDA	Exemption Type	Requested Quantity (ICAP MW)	Granted Quantity (ICAP MW)	Cleared Quantity (ICAP MW)
RTO	Competitive Entry	12,161.0	12,161.0	2,675.6
RTO	Self-Supply	0.0	0.0	0.0
RTO	Unit-Specific	0.0	0.0	0.0
Total		**12,161.0**	**12,161.0**	**2,675.6**

A further discussion of the 2020/2021 BRA results and additional information regarding the 2020/2021 RPM BRA are detailed in the body of this report. The discussion also provides a comparison of the 2020/2021 auction results to the results from the 2007/2008 through 2019/2020 RPM Auctions.

2020/2021 RPM Base Residual Auction Results

2020/2021 Base Residual Auction Results Discussion

Table 1 contains a summary of the RTO clearing prices, cleared unforced capacity, and implied cleared reserve margins resulting from the 2020/2021 RPM BRA in comparison to those from 2007/2008 through 2019/2020 RPM BRAs.

Table 1 –RPM Base Residual Auction Resource Clearing Price Results in the RTO

	RTO													
Auction Results	2007/2008	2008/2009	2009/2010	2010/2011	2011/2012[1]	2012/2013	2013/2014[2]	2014/2015[3]	2015/2016[4]	2016/2017[5]	2017/2018	2018/2019	2019/2020	2020/2021[6]
Resource Clearing Price ($/MW-day)	$40.80	$111.92	$102.04	$174.29	$110.00	$16.46	$27.73	$125.99	$136.00	$59.37	$120.00	$164.77	$100.00	$76.53
Cleared UCAP (MW)	129,409.2	129,597.6	132,231.8	132,190.4	132,221.5	136,143.5	152,743.3	149,974.7	164,561.2	169,159.7	167,003.7	166,836.9	167,305.9	165,109.2
Reserve Margin	19.1%	17.4%	17.6%	16.4%	17.9%	20.5%	19.7%	18.8%	19.3%	20.3%	19.7%	19.8%	22.4%	23.3%

1) 2011/2012 BRA was conducted without Duquesne zone load.
2) 2013/2014 BRA includes ATSI zone
3) 2014/2015 BRA includes Duke zone
4) 2015/2016 BRA includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
5) 2016/2017 BRA includes EKPC zone
6) 2020/2021 BRA Cleared UCAP (MW) includes Annual and matched Seasonal Capacity Performance sell offers

The Reserve Margin presented in Table 1 represents the percentage of installed capacity cleared in RPM and committed by FRR entities in excess of the RTO load (including load served under the Fixed Resource Requirement alternative). The 2020/2021 RPM BRA cleared 165,109.2 MW of unforced capacity in the RTO representing a 23.9% reserve margin. The reserve margin for the entire RTO is 23.3%, or 6.7% higher than the target reserve margin of 16.6%, when the Fixed Resource Requirement (FRR) load and resources are considered.

New Generation Resource Participation

The total quantity of new Generation Capacity Resources offered into the auction was 3,143.5 MW (UCAP) comprised of 2,536.6 MW of new generation units and 606.9 MW of uprates to existing generation units. The quantity of new Generation Capacity Resources cleared was 2,823.8 MW (UCAP) comprised of 2,389.3 MW (UCAP) from new generation units, predominantly natural gas combined cycle, and 434.5 MW from uprates to existing generation units.

Table 2A shows the breakdown, by major LDA, of capacity in UCAP terms of new units and uprates at existing units offered in the auction and capacity actually clearing in the auction. Ninety percent of the new generation capacity that offered into the 2020/2021BRA cleared the auction.

2020/2021 RPM Base Residual Auction Results

Table 2A – Offered and Cleared New Generation Capacity by LDA (in UCAP MW)

	Offered			Cleared ****		
LDA	Uprate	New Unit	Total	Uprate	New Unit	Total
EMAAC	199.7	42.8	**242.5**	86.1	7.9	**94.0**
MAAC **	287.8	1,042.8	**1,330.6**	174.2	1,439.0	**1,613.2**
Total RTO ***	606.9	2,536.6	**3,143.5**	434.5	2,389.3	**2,823.8**

* All MW Values are in UCAP Terms

** MAAC includes EMAAC

*** RTO includes MAAC

**** Cleared MW values may include new units that have offered in a prior BRA and not cleared

Capacity Import Participation

The quantity of capacity imports cleared in the 2020/2021 BRA were 3,997.2 MW (UCAP) which represents an increase of 121.3 MW from the imports that cleared in the 2019/2020 BRA. The majority of the imports are from resources located in regions west of the PJM RTO. All external generation capacity that has cleared in the 2020/21 BRA has met the requirements for a CIL exception.

Table 2B – Offered and Cleared Capacity Imports (in UCAP MW)

	External Source Zones					
Imports *	NORTH	WEST 1	WEST 2	SOUTH 1	SOUTH 2	Total
Offered MW (UCAP)	214.1	1,219.6	2,144.5	804.2	579.4	**4,961.8**
Cleared MW (UCAP)	214.1	1,130.1	1,327.2	746.4	579.4	**3,997.2**

* Offered and Cleared MW quantities include resources that met the requirements for a CIL Exception and those associated with pre-OATT grandfathered transmission Attachment G of Manual 14B provides a mapping of outside Balancing Authorities to the External Source Zones.

Demand Resource Participation

The total quantity of DR offered into the 2020/2021 BRA was 9,846.7 MW (UCAP), representing a decrease of 16.7% from the DR that offered into the 2019/2020 BRA. Of the 9,846.7 MW of total DR that offered in this auction, 7,820.4 MW cleared. The cleared DR is 2,527.6 MW less than that which cleared in the 2019/2020 BRA. Of the 7,820.4 MW of DR cleared in the 2020/2021 BRA, 7,531.5 MW were cleared as the Annual Capacity Performance Product and 288.9 MW were cleared as the summer seasonal Capacity

2020/2021 RPM Base Residual Auction Results

Performance product. Table 3A contains a comparison of the DR Offered and Cleared in 2019/2020 BRA & 2020/2021 BRA represented in UCAP.

Energy Efficiency Resource Participation

An EE resource is a project that involves the installation of more efficient devices/equipment or the implementation of more efficient processes/systems exceeding then-current building codes, appliance standards, or other relevant standards at the time of installation as known at the time of commitment. The EE resource must achieve a permanent, continuous reduction in electric energy consumption (during the defined EE performance hours) that is not reflected in the peak load forecast used for the BRA for the Delivery Year for which the EE resource is proposed. The EE resource must be fully implemented at all times during the Delivery Year, without any requirement of notice, dispatch, or operator intervention. Of the 2,242.5 MW of energy efficiency that offered into the 2020/2021 BRA, 1,710.2 MW of EE resources cleared in the auction. Of the 1,710.2 MW of EE Resources cleared in the 2020/2021 BRA, 1,607.4 MW was cleared as the Annual Capacity Performance Product and 102.8 MW were cleared as the summer seasonal Capacity Performance product.

Table 3B contains a summary of the DR and EE resources that offered and cleared by zone in the 2020/2021 BRA. Approximately 79.4% of the DR and 76.3% of the EE resources that were offered into the BRA cleared.

Figure 1 illustrates the demand side participation in the PJM Capacity Market from 2005/2006 Delivery Year to the 2020/2021 Delivery Year. Demand side participation includes active load management (ALM) prior to 2007/2008 Delivery Year, Interruptible Load for Reliability (ILR) and DR offered into each BRA and nominated in FRR Plans, and EE resources starting with the 2012/2013 Delivery Year. The demand side participation in the capacity market has increased dramatically since the inception of RPM in the 2007/2008 Delivery Year through the 2015/2016 BRA, but as shown in Figure 1, total demand side participation and cleared resources for the 2020/2021 BRA have fallen below the levels seen in the 2014/2015 BRA.

2020/2021 RPM Base Residual Auction Results

Table 3A – Comparison of Demand Resources Offered and Cleared in 2019/2020 BRA & 2020/2021 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	2019/2020	2020/2021 *	Increase in Offered MW	2019/2020	2020/2021 *	Increase in Cleared MW
EMAAC	AECO	153.8	72.5	**(81.3)**	145.7	62.8	**(82.9)**
EMAAC/DPL-S	DPL	397.9	330.0	**(67.9)**	371.6	213.4	**(158.2)**
EMAAC	JCPL	231.2	160.1	**(71.1)**	200.8	143.9	**(56.9)**
EMAAC	PECO	565.1	408.3	**(156.8)**	527.4	363.3	**(164.1)**
PSEG/PS-N	PSEG	427.8	353.5	**(74.3)**	380.7	327.7	**(53.0)**
EMAAC	RECO	10.3	3.8	**(6.5)**	10.3	3.7	**(6.6)**
EMAAC Sub Total		**1,786.1**	**1,328.2**	**(457.9)**	**1,636.5**	**1,114.8**	**(521.7)**
PEPCO	PEPCO	570.4	346.7	**(223.7)**	483.3	211.9	**(271.4)**
BGE	BGE	729.3	430.5	**(298.8)**	256.4	246.5	**(9.9)**
MAAC	METED	379.8	294.0	**(85.8)**	321.7	241.8	**(79.9)**
MAAC	PENELEC	392.0	356.6	**(35.4)**	339.4	304.1	**(35.3)**
PPL	PPL	815.6	693.5	**(122.1)**	739.8	579.9	**(159.9)**
MAAC Sub Total**		**4,673.2**	**3,449.5**	**(1,223.7)**	**3,777.1**	**2,699.0**	**(1,078.1)**
RTO	AEP	1,603.1	1,408.5	**(194.6)**	1,416.1	1,010.5	**(405.6)**
RTO	APS	1,039.4	933.2	**(106.2)**	926.0	709.8	**(216.2)**
ATSI/ATSI-C	ATSI	978.0	815.8	**(162.2)**	897.6	688.7	**(208.9)**
COMED	COMED	1,792.0	1,794.4	**2.4**	1,757.4	1,512.9	**(244.5)**
DAY	DAY	237.6	212.4	**(25.2)**	219.8	164.6	**(55.2)**
DEOK	DEOK	248.8	200.8	**(48.0)**	236.7	152.8	**(83.9)**
RTO	DOM	816.8	700.2	**(116.6)**	729.7	585.3	**(144.4)**
RTO	DUQ	286.8	192.6	**(94.2)**	247.2	159.9	**(87.3)**
RTO	EKPC	142.3	139.3	**(3.0)**	140.4	136.9	**(3.5)**
Grand Total		**11,818.0**	**9,846.7**	**(1,971.3)**	**10,348.0**	**7,820.4**	**(2,527.6)**

* 2020/2021 MW values include both Annual and Summer-Period Capacity Performance DR

** MAAC sub-total includes all MAAC Zones

2020/2021 RPM Base Residual Auction Results

Table 3B – Comparison of Demand Resources and Energy Efficiency Resources Offered and Cleared in the 2020/2021 BRA (in UCAP MW)

		Offered MW (UCAP)			Cleared MW (UCAP)		
LDA	Zone	DR	EE	Total	DR	EE	Total
EMAAC	AECO	72.5	31.6	**104.1**	62.8	27.2	**90.0**
EMAAC/DPL-S	DPL	330.0	57.9	**387.9**	213.4	47.7	**261.1**
EMAAC	JCPL	160.1	52.5	**212.6**	143.9	47.9	**191.8**
EMAAC	PECO	408.3	82.3	**490.6**	363.3	71.4	**434.7**
PSEG/PS-N	PSEG	353.5	112.6	**466.1**	327.7	93.3	**421.0**
EMAAC	RECO	3.8	6.4	**10.2**	3.7	5.6	**9.3**
EMAAC Sub Total		**1,328.2**	**343.3**	**1,671.5**	**1,114.8**	**293.1**	**1,407.9**
PEPCO	PEPCO	346.7	99.9	**446.6**	211.9	66.8	**278.7**
BGE	BGE	430.5	156.6	**587.1**	246.5	125.1	**371.6**
MAAC	METED	294.0	33.9	**327.9**	241.8	14.9	**256.7**
MAAC	PENELEC	356.6	28.1	**384.7**	304.1	10.6	**314.7**
PPL	PPL	693.5	59.6	**753.1**	579.9	34.5	**614.4**
MAAC Sub Total**		**3,449.5**	**721.4**	**4,170.9**	**2,699.0**	**545.0**	**3,244.0**
RTO	AEP	1,408.5	168.9	**1,577.4**	1,010.5	110.2	**1,120.7**
RTO	APS	933.2	55.5	**988.7**	709.8	36.8	**746.6**
ATSI/ATSI-C	ATSI	815.8	52.7	**868.5**	688.7	33.2	**721.9**
COMED	COMED	1,794.4	808.1	**2,602.5**	1,512.9	701.9	**2,214.8**
DAY	DAY	212.4	54.3	**266.7**	164.6	33.1	**197.7**
DEOK	DEOK	200.8	67.4	**268.2**	152.8	65.8	**218.6**
RTO	DOM	700.2	274.8	**975.0**	585.3	168.9	**754.2**
RTO	DUQ	192.6	30.0	**222.6**	159.9	12.3	**172.2**
RTO	EKPC	139.3	9.4	**148.7**	136.9	3.0	**139.9**
Grand Total		**9,846.7**	**2,242.5**	**12,089.2**	**7,820.4**	**1,710.2**	**9,530.6**

* MW values include both Annual and Summer-Period Capacity Performance DR and EE

** MAAC sub-total includes all MAAC Zones

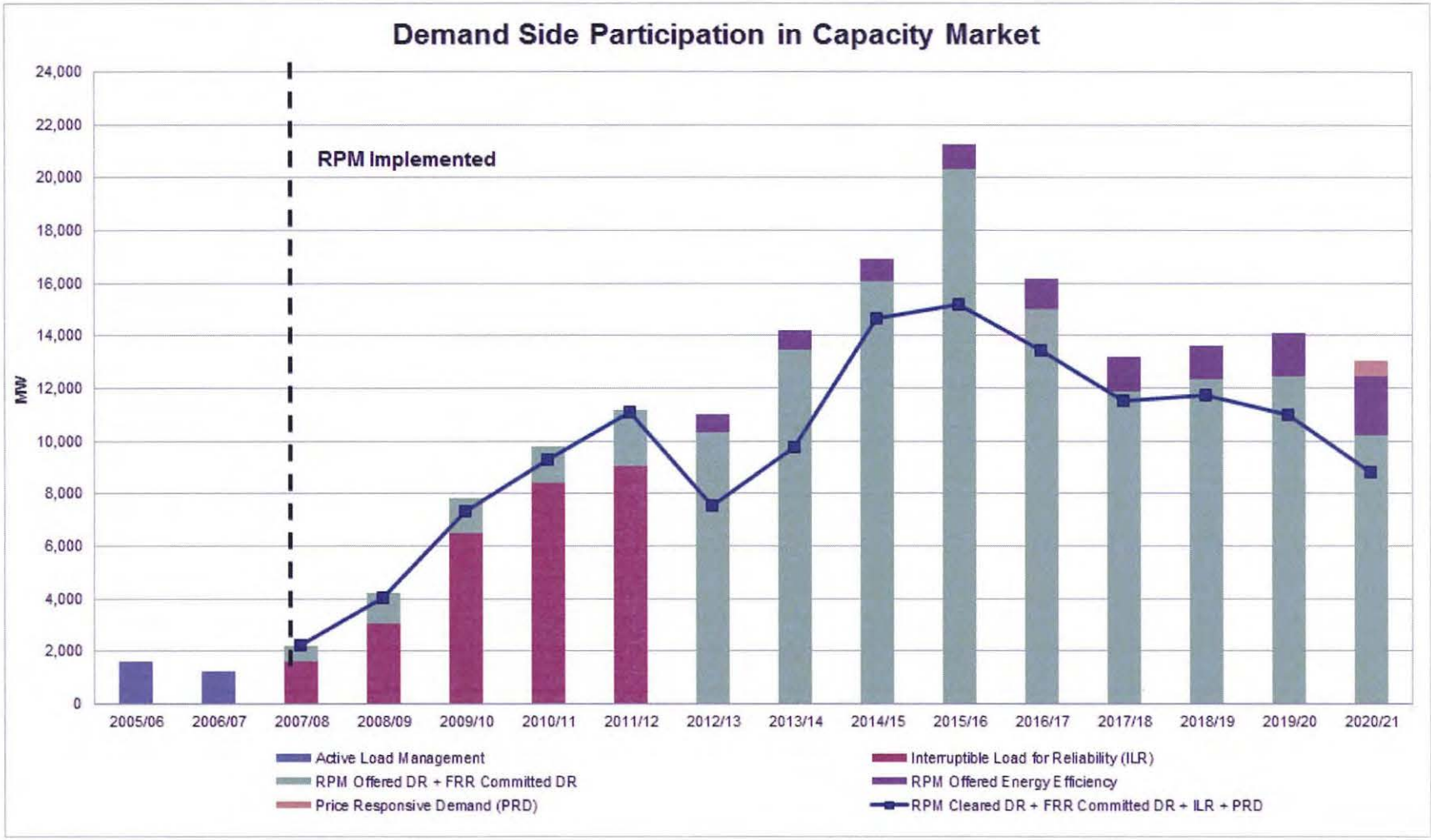
2020/2021 RPM Base Residual Auction Results

Table 3C – Breakdown of Annual and Seasonal Capacity Performance Resources by Resource Type and Season that Offered and Cleared in the 2020/2021 BRA (in UCAP MW)

	Offered MW (UCAP)			Cleared MW (UCAP)		
Resource Type	Annual	Summer	Winter	Annual	Summer	Winter
GEN	170,591.7	184.7	485.9	155,572.4	6.2	397.9
DR	8,367.2	1,479.5	-	7,531.5	288.9	-
EE	1,839.0	403.5	-	1,607.4	102.8	-
Total	**180,797.9**	**2,067.7**	**485.9**	**164,711.3**	**397.9**	**397.9**

2020/2021 RPM Base Residual Auction Results

Figure 1 – Demand Side Participation in the PJM Capacity Market



2020/2021 RPM Base Residual Auction Results

Renewable Resource Participation

887.7 MW of wind resources were offered into and cleared the 2020/2021 BRA as compared to 969 MW of wind resources that offered into and cleared the 2019/2020 BRA. Of the 887.7 MW of wind resources cleared in the 2020/2021 BRA, 504.3 MW were cleared as the Annual Capacity Performance Product and 383.4 MW were cleared as the winter seasonal Capacity Performance product. The capacity factor applied to wind resources is typically 13%, meaning that for every 100 MW of wind energy, 13 MW are eligible to meet capacity requirements. The 887.7 MW of cleared wind capacity translates to approximately 6,828.5 MW of wind energy nameplate capability that is expected to be available in the 2020/2021 Delivery Year.

125.3 MW of solar resources were offered into and cleared the 2020/2021 BRA as compared to 335 MW of solar resources that offered into and cleared the 2019/2020 BRA. Of the 125.3 MW of solar resources cleared in the 2020/2021 BRA, 119.1 MW were cleared as the Annual Capacity Performance Product and 6.2 MW were cleared as the summer seasonal Capacity Performance product. The capacity factor applied to solar resources is typically 38%, meaning that for every 100 MW of solar energy, 38 MW are eligible to meet capacity requirements. The 125.3 MW of cleared solar capacity translates to approximately 329.7 MW of nameplate solar energy capability that is expected to be available in the 2020/2021 Delivery Year.

Price Responsive Demand Participation

PRD participated for the first time in the 2020/2021 BRA. A total Nominal PRD Value of 558 MW was elected and committed in the 2020/2021 BRA. PRD is provided by a PJM Member that represents retail customers having the ability to predictably reduce consumption in response to changing wholesale prices. In the PJM Capacity Market, a PRD Provider may voluntarily make a firm commitment of the quantity of PRD that will reduce its consumption in response to real time energy price during a Delivery Year. A PRD Provider that is committing PRD in a BRA must also submit a PRD election in the eRPM system which indicates the Nominal PRD Value in MWs that the PRD Provider is willing to commit at different reservation prices ($/MW-day). The VRR curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW quantity of elected PRD where the leftward shift occurs only for the portion of the VRR Curve at or above the PRD Reservation price. As shown in the 2020/2021 Planning Parameters, 558 MW of PRD across the RTO has elected to participate in the 2020/2021 BRA: 330 MW in the BGE LDA, 170 MW in the PEPCO LDA, and 58 MW in the EMAAC LDA (with 23 MW located in the DPL-South LDA). The VRR Curve of the RTO and each affected LDA is shifted leftward along the horizontal axis by the UCAP MW value of these quantities at the PRD Reservation Price. Once committed in a BRA, a PRD commitment cannot be replaced; the commitment can only be satisfied through the registration of price response load in the DR Hub system prior to or during the Delivery Year.

2020/2021 RPM Base Residual Auction Results

LDA Results

An LDA was modeled in the BRA and had a separate VRR Curve if (1) the LDA has a CETO/CETL margin that is less than 115%; or (2) the LDA had a locational price adder in any of the three immediately preceding BRAs; or (3) the LDA is EMAAC, SWMAAC, and MAAC. An LDA not otherwise qualifying under the above three tests may also be modeled if PJM finds that the LDA is determined to be likely to have a Locational Price Adder based on historic offer price levels or if such LDA is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards.

As a result of the above criteria, MAAC, EMAAC, SWMAAC, PSEG, PS-NORTH, DPL-SOUTH, PEPCO, ATSI, ATSI-Cleveland, COMED, BGE, PL, DAY and DEOK were modeled as LDAs in the 2020/2021 RPM Base Residual Auction. The MAAC, EMAAC, ComEd and DEOK LDAs were binding constraints in the auction resulting in a Locational Price Adder for these LDAs. A Locational Price Adder represents the difference in Resource Clearing Prices for the Capacity Performance product between a resource in a constrained LDA and the immediate higher level LDA. Table 4 contains a summary of the clearing results in the LDAs from the 2020/2021 RPM Base Residual Auction.

Table 4 –RPM Base Residual Auction Clearing Results in the LDAs

Auction Results	RTO	MAAC	SWMAAC	PEPCO	BGE	EMAAC	DPL-SOUTH	PSEG	PS-NORTH	ATSI	ATSI-CLEVELAND	PPL	COMED	DAY	DEOK
Offered MW (UCAP) *	183,351.5	72,972.7	12,895.4	6,941.1	3,543.3	31,045.0	1,687.9	5,699.5	3,359.1	11,705.2	2,467.4	10,929.7	27,436.8	1,669.2	3,166.7
Cleared MW (UCAP) **	165,109.2	65,817.9	10,354.4	5,918.6	2,296.9	29,608.2	1,647.2	5,097.2	2,975.4	9,925.1	1,857.9	10,345.0	23,960.3	1,527.1	2,430.3
System Marginal Price	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53	$76.53
Locational Price Adder ***	-	$9.51	-	-	-	$101.83	-	-	-	-	-	-	$111.59	-	$53.47
Resource Clearing Price	$76.53	$86.04	$86.04	$86.04	$86.04	$187.87	$187.87	$187.87	$187.87	$76.53	$76.53	$86.04	$188.12	$76.53	$130.00

* Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

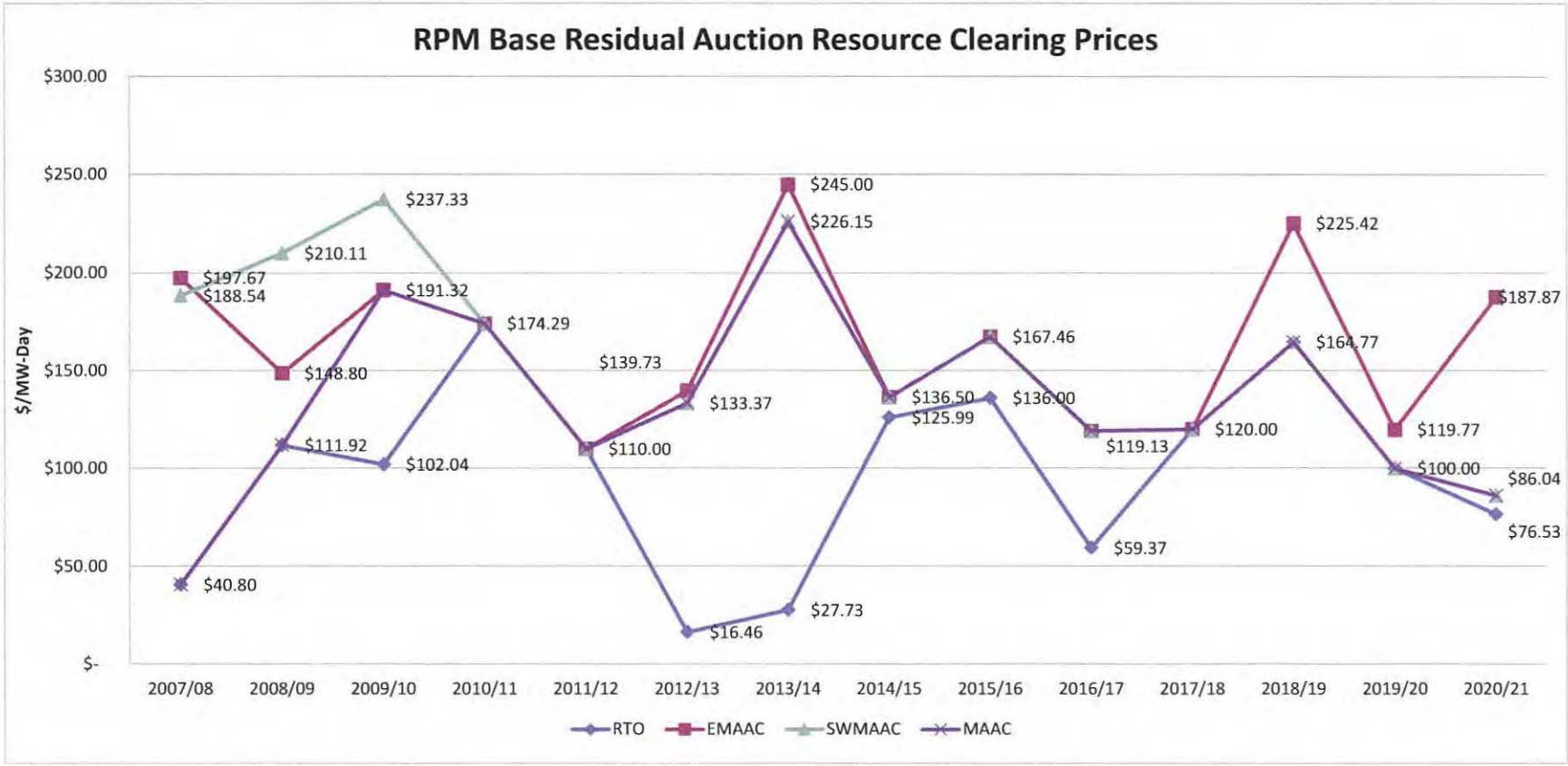
** Cleared MW values include Annual and matched Seasonal Capacity Performance sell offers within the LDA

*** Locational Price Adder is with respect to the immediate parent LDA

Since the MAAC LDA, EMAAC LDA, ComEd LDA and DEOK LDAs were constrained LDAs, Capacity Transfer Rights (CTRs) will be allocated to loads in these constrained LDA for the 2020/2021 Delivery Year. CTRs are allocated by load ratio share to all Load Serving Entities (LSEs) in a constrained LDA that has a higher clearing price than the unconstrained region. CTRs serve as a credit back to the LSEs in the constrained LDA for use of the transmission system to import less expensive capacity into that constrained LDA and are valued at the difference in the clearing prices of the constrained and unconstrained regions.

2020/2021 RPM Base Residual Auction Results

Figure 2 – Base Residual Auction Resource Clearing Prices



* 2014/2015 through 2020/2021 Prices reflect the Annual Resource Clearing Prices.

2020/2021 RPM Base Residual Auction Results

Table 5 contains a summary of the RTO resources for each cleared BRA from 2008/2009 through the 2020/2021 Delivery Years. The summary includes all resources located in the RTO (including FRR Capacity Plans).

A total of 212,995.6 MW of installed capacity was eligible to be offered into the 2020/2021 Base Residual Auction, with 5,440.5 MW from external resources. As illustrated in Table 5, the amount of capacity exports in the 2020/2021 auction increased by 1.6 MW from that of the previous auction and FRR commitments decreased by 1,453.7 MW from the 2019/2020 Delivery Year to 13,931.6 MW.

A total of 189,917.8 MW of capacity was offered into the Base Residual Auction. This is a decrease of 4,325.2 MW from that which was offered into the 2019/2020 BRA. A total of 23,077.8 MW was eligible, but not offered due to either (1) inclusion in an FRR Capacity Plan, (2) export of the resource, or (3) having been excused from offering into the auction. Resources were excused from the must offer requirement for the following reasons: approved retirement requests not yet reflected in eRPM, resources categorically exempt from the Capacity Performance must-offer requirement, resources which received an exemption from the must-offer or Capacity Performance must-offer requirement and excess capacity owned by an FRR entity.

2020/2021 RPM Base Residual Auction Results

Table 5 –RPM Base Residual Auction Generation, Demand, and Energy Efficiency Resource Information in the RTO

	RTO[1]												
Auction Supply (all values in ICAP)	2008/2009	2009/2010	2010/2011	2011/2012[2]	2012/2013	2013/2014[3]	2014/2015[4]	2015/2016[5]	2016/2017[6]	2017/2018	2018/2019	2019/2020	2020/2021[7]
Internal PJM Capacity	166,037.9	167,026.3	168,457.3	169,241.6	179,791.2	195,633.4	199,375.5	207,559.1	208,098.0	202,477.4	203,300.6	207,579.6	207,555.1
Imports Offered	2,612.0	2,563.2	2,982.4	6,814.2	4,152.4	4,766.1	7,620.2	4,649.7	8,412.2	6,300.9	5,724.6	4,821.4	5,440.5
Total Eligible RPM Capacity	**168,649.9**	**169,589.5**	**171,439.7**	**176,055.8**	**183,943.6**	**200,399.5**	**206,995.7**	**212,208.8**	**216,510.2**	**208,778.3**	**209,025.2**	**212,401.0**	**212,995.6**
Exports / Delistings	4,205.8	2,240.9	3,378.2	3,389.2	2,783.9	2,624.5	1,230.1	1,218.8	1,218.8	1,223.2	1,313.4	1,318.2	1,319.8
FRR Commitments	24,953.5	25,316.2	26,305.7	25,921.2	26,302.1	25,793.1	33,612.7	15,997.9	15,576.6	15,776.1	15,793.0	15,385.3	13,931.6
Excused	722.0	1,121.9	1,290.7	1,580.0	1,732.2	1,825.7	3,255.2	8,712.9	8,524.0	4,305.3	2,348.4	1,454.5	7,826.4
Total Eligible RPM Capacity - Excused	**29,881.3**	**28,679.0**	**30,974.6**	**30,890.4**	**30,818.2**	**30,243.3**	**38,098.0**	**25,929.6**	**25,319.4**	**21,304.6**	**19,454.8**	**18,158.0**	**23,077.8**
Remaining Eligible RPM Capacity	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**
Generation Offered	138,076.7	140,003.6	139,529.5	143,568.1	142,957.7	156,894.1	153,048.1	166,127.8	176,145.3	175,329.5	177,592.1	181,866.4	178,807.1
DR Offered	691.9	906.9	935.6	1,597.3	9,535.4	12,528.7	15,043.1	19,243.6	13,932.9	10,855.2	10,772.8	10,859.2	9,047.8
EE Offered	0.0	0.0	0.0	0.0	632.3	733.4	806.5	907.8	1,112.6	1,289.0	1,205.5	1,517.4	2,062.9
Total Eligible RPM Capacity Offered	**138,768.6**	**140,910.5**	**140,465.1**	**145,165.4**	**153,125.4**	**170,156.2**	**168,897.7**	**186,279.2**	**191,190.8**	**187,473.7**	**189,570.4**	**194,243.0**	**189,917.8**
Total Eligible RPM Capacity Unoffered	**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**

1) RTO numbers include all LDAs.
2) All generation in the Duquesne zone is considered external to PJM for the 2011/2012 BRA.
3) 2013/2014 includes ATSI zone and generation
4) 2014/2015 includes Duke zone and generation
5) 2015/2016 includes a significant portion of AEP and DEOK zone load previously under the FRR Alternative
6) 2016/2017 includes EKPC zone
7) 2020/2021 Generation, DR, and EE Offered MW values include Annual, Summer-Period, and Winter-Period Capacity Performance sell offers

Table 6 shows the Generation, DR, and EE Resources Offered and Cleared in the RTO translated into Unforced Capacity (UCAP) MW amounts. Participants' sell offer EFORd values were used to translate the generation installed capacity values into unforced capacity (UCAP) values. DR sell offers and EE sell offers were converted into UCAP using the appropriate Forecast Pool Requirement (FPR) for the Delivery Year.

In UCAP terms, a total of 183,351.5 MW were offered into the 2020/2021 BRA, comprised of 171,262.3 MW of generation capacity, 9,846.7 MW of capacity from DR, and 2,242.5 MW of capacity from EE resources. Of those offered, a total of 165,109.2 MW of capacity was cleared in the BRA.

Of the 165,109.2 MW of capacity that cleared in the auction, a total of 155,976.5 MW cleared from Generation Capacity Resources, 7,820.4 MW cleared from DR, and 1,710.2 MW cleared from EE resources, 397.9 MW of which cleared as matched seasonal CP

2020/2021 RPM Base Residual Auction Results

resources. Capacity that was offered but not cleared in the BRA Auction will be eligible to offer into the First, Second and Third Incremental Auctions for the 2020/2021 Delivery Year.

Table 6 – Generation, Demand Resources, and Energy Efficiency Resources Offered and Cleared in UCAP MW

	RTO*												
Auction Results	2008/2009	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021 ***
Generation Offered	131,164.8	132,614.2	132,124.8	136,067.9	134,873.0	147,188.6	144,108.8	157,691.1	168,716.0	166,204.8	166,909.6	172,071.2	171,262.3
DR Offered	715.8	936.8	967.9	1,652.4	9,847.6	12,952.7	15,545.6	19,956.3	14,507.2	11,293.7	11,675.5	11,818.0	9,846.7
EE Offered	-	-	-	-	652.7	756.8	831.9	940.3	1,156.8	1,340.0	1,306.1	1,650.3	2,242.5
Total Offered	**131,880.6**	**133,551.0**	**133,092.7**	**137,720.3**	**145,373.3**	**160,898.1**	**160,486.3**	**178,587.7**	**184,380.0**	**178,838.5**	**179,891.2**	**185,539.5**	**183,351.5**
Generation Cleared	129,061.4	131,338.9	131,251.5	130,856.6	128,527.4	142,782.0	135,034.2	148,805.9	155,634.3	154,690.0	154,506.0	155,442.8	155,976.5
DR Cleared	536.2	892.9	939.0	1,364.9	7,047.2	9,281.9	14,118.4	14,832.8	12,408.1	10,974.8	11,084.4	10,348.0	7,820.4
EE Cleared	-	-	-	-	568.9	679.4	822.1	922.5	1,117.3	1,338.9	1,246.5	1,515.1	1,710.2
Total RTO Cleared	**129,597.6**	**132,231.8**	**132,190.5**	**132,221.5**	**136,143.5**	**152,743.3**	**149,974.7**	**164,561.2**	**169,159.7**	**167,003.7**	**166,836.9**	**167,305.9**	**165,109.2**
Uncleared	2,283.0	1,319.2	902.2	5,498.8	9,229.8	8,154.8	10,511.6	14,026.5	15,220.3	11,834.8	13,054.3	18,233.6	18,242.3

* RTO numbers include all LDAs

** UCAP calculated using sell offer EFORd for Generation Resources. DR and EE UCAP values include appropriate FPR and DR Factor.

*** 2020/2021 BRA Generation, DR, and EE offered and cleared values include Annual, Summer-Period, and Winter-Period Capacity Performan

*** 2020/2021 BRA Total RTO Cleared MW value includes Annual and matched Seasonal Capacity Performance sell offers

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Table 7 contains a summary of capacity additions and reductions from the 2007/2008 BRA to the 2020/2021 BRA. A total of 4,257.5 MW of incrementally new capacity in PJM was available for the 2020/2021 BRA. This incrementally new capacity includes new Generation Capacity Resources and capacity upgrades to existing Generation Capacity Resources. The increase is offset by generation capacity deratings on existing Generation Capacity Resources and an increase in the quantity of offered DR and EE to yield a net decrease of 24.5 MW of installed capacity.

Table 7 also illustrates the total amount of resource additions and reductions over fourteen Delivery Years since the implementation of the RPM construct. Over the period covering the first fourteen RPM BRAs, 50,792.0 MW of new generation capacity was added, which was partially offset by 39,639.5 MW of capacity de-ratings or retirements over the same period. Additionally, 9,485.6 MW of new DR and 2,062.9 MW of new EE resources were offered over the course of the fourteen Delivery Years since RPM's inception. The total net increase in installed capacity in PJM over the period of the last fourteen RPM auctions was 22,701.0 MW.

Table 7 – Incremental Capacity Resource Additions and Reductions to Date

	RTO*														
Capacity Changes (in ICAP)	**2007/2008**	**2008/2009**	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014[1]**	**2014/2015[2]**	**2015/2016**	**2016/2017[3]**	**2017/2018**	**2018/2019**	**2019/2020**	**2020/2021**	**Total**
Increase in Generation Capacity	602.0	724.2	1,272.3	1,776.2	3,576.3	1,893.5	1,737.5	1,582.8	8,207.0	6,806.0	6,973.3	5,055.6	6,327.8	4,257.5	50,792.0
Decrease in Generation Capacity	-674.6	-375.4	-550.2	-301.8	-264.7	-3,253.9	-1,924.1	-1,550.1	-6,432.6	-4,992.0	-9,760.1	-3,620.8	-2,923.1	-3,016.1	-39,639.5
Net Increase in Demand Resource Capacity**	555.0	574.7	215.0	28.7	661.7	7,938.1	2,993.3	2,514.4	4,200.5	-5,310.7	-3,077.7	-82.4	86.4	-1,811.4	9,485.6
Net Increase in Energy Efficiency Capacity**	0.0	0.0	0.0	0.0	0.0	632.3	101.1	73.1	101.3	204.8	176.4	-83.5	311.9	545.5	2,062.9
Net Increase in Installed Capacity	**482.4**	**923.5**	**937.1**	**1503.1**	**3973.3**	**7,210.0**	**2,907.8**	**2,620.2**	**6,076.2**	**-3,291.9**	**-5,688.1**	**1,268.9**	**3,803.0**	**-24.5**	**22,701.0**

* RTO numbers include all LDAs

** Values are with respect to the quantity offered in the previous year's Base Residual Auction.

1) Does not include Existing Generation located in ATSI Zone

2) Does not include Existing Generation located in Duke Zone

3) Does not include Existing Generation located in EKPC Zone

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Table 7A provides a further breakdown of the generation increases and decreases for the 2020/2021 Delivery Year on an LDA basis.

Table 7A – Generation Increases and Decreases by LDA Effective 2020/2021 Delivery Year

LDA	Increases	Decreases
EMAAC	274.9	(2,268.7)
MAAC	1,367.1	(2,368.5)
Total RTO	**4,257.5**	**(3,016.1)**

All Values in ICAP terms
*MAAC includes EMAAC
**RTO includes MAAC

Table 8 provides a breakdown of the new capacity offered into the each BRA into the categories of new resources, reactivated units, and uprates to existing capacity, and then further down into resource type. As shown in this table, there was a significant quantity of generating capacity from new resources and uprates to existing resources offered into the 2020/2021 BRA. The capacity offered in the 2020/2021 BRA resulted from both new generating resources and uprates to existing resources including gas, diesel, wind, and solar resources. The largest growth remains in combined cycle plants.

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Table 8 – Further Breakdown of Incremental Capacity Resource Additions from 2007/2008 to 2020/2021

	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Fuel Cell	Total
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3						19.0
	2008/2009			27.0					66.1		93.1
	2009/2010	399.5		23.8		53.0					476.3
	2010/2011	283.3	580.0	23.0					141.4		1,027.7
	2011/2012	416.4	1,135.0			704.8		1.1	75.2		2,332.5
	2012/2013	403.8		7.8		621.3			75.1		1,108.0
	2013/2014	329.0	705.0	6.0		25.0		9.5	245.7		1,320.2
	2014/2015	108.0	650.0	35.1	132.9			28.0	146.6		1,100.6
	2015/2016	1,382.5	5,914.5	19.4	148.4	45.4		13.8	104.9	30.0	7,658.9
	2016/2017	171.1	4,994.5	38.3		24.0		32.1	54.3		5,314.3
	2017/2018	131.0	5,010.0	124.8	6.0	90.0		27.0			5,388.8
	2018/2019	1,032.5	2,352.3	29.9				82.8	127.1		3,624.6
	2019/2020	167.0	6,145.0	29.9				152.3	73.0		6,567.2
	2020/2021		2,410.0	26.3	4.0			94.3	30.2		2,564.8
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0					47.0
	2008/2009					131.0					131.0
	2009/2010										-
	2010/2011	160.0		10.7							170.7
	2011/2012	80.0				101.0					181.0
	2012/2013										-
	2013/2014										-
	2014/2015			9.0							9.0
	2015/2016										-
	2016/2017					21.0					21.0
	2017/2018					991.0					991.0
	2018/2019										-
	2019/2020										-
	2020/2021										-
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0				536.0
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4				500.1
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5		796.0
	2010/2011	117.3	163.0		48.0	89.2	160.3				577.8
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7		1,062.8
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8		785.5
	2013/2014	56.4	59.0	0.3		215.0	47.0		39.6		417.3
	2014/2015	104.9		0.5	41.5	138.6	107.0	7.1	73.6		473.2
	2015/2016	216.8	72.0	4.7	15.7	63.4	149.2	2.2	24.1		548.1
	2016/2017	436.6	420.0	3.3	7.4	484.3	102.6	1.7	14.8		1,470.7
	2017/2018	71.9	212.5	5.1	105.9	64.8	11.0	0.4	2.1		473.7
	2018/2019	33.4	548.0	2.4	22.9	11.9	79.3	-	14.9	-	712.8
	2019/2020	29.3	72.5	3.9	5.2	65.3			46.8	-	223.0
	2020/2021	9.3	588.8	1.2	4.6	5.7		1.0	14.7		625.3
	Total	7,115.3	32,585.0	554.6	890.8	4,865.5	1,402.3	453.3	1,452.2	30.0	49,349.0

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Figure 4: Cumulative Generation Capacity Increases by Fuel Type

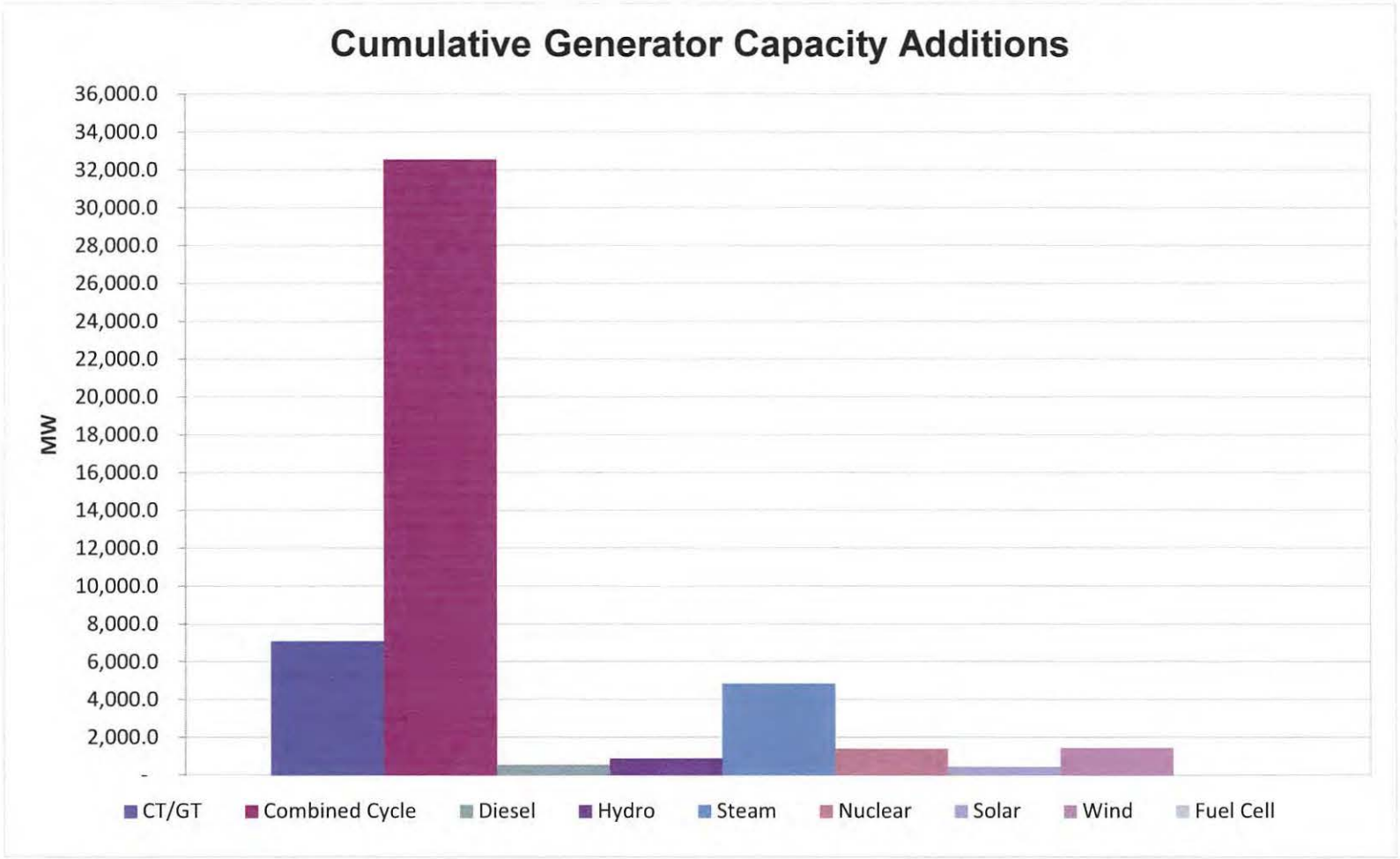

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Table 9 shows the changes that have occurred regarding resource deactivation and retirement since the RPM was approved by FERC. The MW values shown in Table 9 represent the quantity of unforced capacity cleared in the 2020/2021 Base Residual Auction that came from resources that have either withdrawn their request to deactivate, postponed retirement, or been reactivated (i.e., came out of retirement or mothball state for the RPM auctions) since the inception of RPM. This total accounts for 4,369.0 MW of cleared UCAP in the 2020/2021 BRA which equates to 5,380.5 MW of ICAP Offered.

Table 9 – Changes to Generation Retirement Decisions since Commencement of RPM in 2007/2008

	RTO*	
Generation Resource Decision Changes	ICAP Offered	UCAP Cleared
Withdrawn Deactivation Requests	1,486.2	656.4
Postponed or Cancelled Retirement	3,511.2	3,057.6
Reactivation	833.1	655.0
Total	**5,830.5**	**4,369.0**

RPM Impact to Date

As illustrated in Table 5, for the 2020/2021 auction, the capacity exports were 1,319.8 MW and the offered capacity imports were 5,440.5 MW. The difference between the capacity imports and exports results is a net capacity import of 4,120.7 MW. In the planning year preceding the RPM auction implementation, 2006/2007, there was a net capacity export of 2,616.0 MW. In this auction, PJM is now a net importer of 4,120.7 MW. Therefore, RPM's impact on PJM capacity interchange is 6,736.7 MW.

The minimum net impact of the RPM implementation on the availability of Installed Capacity resources for the 2020/2021 planning year can be estimated by adding the net change in capacity imports and exports over the period, the forward demand and energy efficiency resources, the increase in Installed Capacity over the RPM implementation period from Table 8 and the net change in generation retirements from Table 9. Therefore, as illustrated in Table 10, the minimum estimated net impact of the RPM implementation on the availability of capacity in the 2020/2021 compared to what would have happened absent this implementation is 71,501.6 MW.

2020/2021 RPM Base Residual Auction Results

Table 10 shows the details on RPM's impact to date in ICAP terms.

Table 10 – RPM's Impact to Date

Change in Capacity Availability	Installed Capacity MW
New Generation	38,596.0
Generation Upgrades (not including reactivations)	9,202.3
Generation Reactivation	1,550.7
Forward Demand and Energy Efficiency Resources	11,548.5
Cleared ICAP from Withdrawn or Cancelled Retirements	3,867.4
Net increase in Capacity Imports	6,736.7
Total Impact on Capacity Availability in 2020/2021 Delivery Year	**71,501.6**

2020/2021 RPM Base Residual Auction Results

Discussion of Factors Impacting the RPM Clearing Prices

The main factors impacting 2020/2021 RPM BRA clearing prices relative to 2019/2020 BRA clearing prices are provided below, separated out by changes to the demand-side and supply-side of the market.

Changes that impacted the Demand Curve:

- The forecast peak load for the PJM RTO for the 2020/2021 Delivery Year is 153,915 MW which is 3,273 MW or about 2.1% below the forecast peak load of 157,188 MW for the 2019/2020 BRA.

- 558 MW of Price Responsive Demand has elected to participate in the 2020/2021 Base Residual Auction: 330 MW in the BGE LDA, 170 MW in the PEPCO LDA, and 58 MW in the EMAAC LDA (with 23 MW located in the DPL-South LDA).

- The reliability requirement for RPM load for the PJM RTO for the 2020/2021 Deliver Year is 2,800 MW below that of the 2019/2020 BRA due to the lower forecasted peak load and the PRD election.

Changes that impacted the Supply Curve:

- The 2020/2021 BRA is the first BRA for which PJM has procured only Capacity Performance ("CP") Resources.
    - CP capacity offered by intermittent resources is 3,400 MW lower than the total capacity offered by intermittent resources in the 2019/2020 BRA
    - CP capacity offered by DR is 2,085 MW lower than the total capacity offered by DR in the 2019/2020 BRA
    - 398 MW of seasonal capacity resources cleared in an aggregated manner to form a year-round commitment. 398 MW of summer CP resources comprised of 289 MW of summer DR, 103 MW of summer EE and 6 MW of intermittent resources cleared along with 398 MW of winter CP resources comprised mainly of winter capability from wind resources
- New generation capacity of 3,144 MW was offered into the BRA comprised of 2,537 of new generation and 607 MW of uprates.
- The RCP of constrained LDAs was also impacted by changes in CETL values. A decrease in CETL acts as a decrease in supply for an importing LDA.

STAFF-DR-02-077

REQUEST:

Refer to the Verderame Testimony, page 22, lines 15-17. Also, refer to Case No. 2017-00186,[1] Exhibit 5, page 16 of 106.

a. Subject to Commission approval, confirm that all six unites at Woodsdale are scheduled to have their construction completed by April 15, 2019, and be in service by April 30, 2019.

b. Provide the amount by account the amount of operations and maintenance expense at Woodsdale for 2016, the base period, and the PJM 2019/2020 Delivery Year.

RESPONSE:

a. Yes, see ATTACHMENT STAFF-DR-02-077(a) for the schedule that has all 6 units fuel oil system in service by early May, 2019 with the assumption that CPCN approval is received by mid December 2017.

b. See ATTACHMENT STAFF-DR-02-077(b).

PERSON RESPONSIBLE: Troy A. Wilhelm

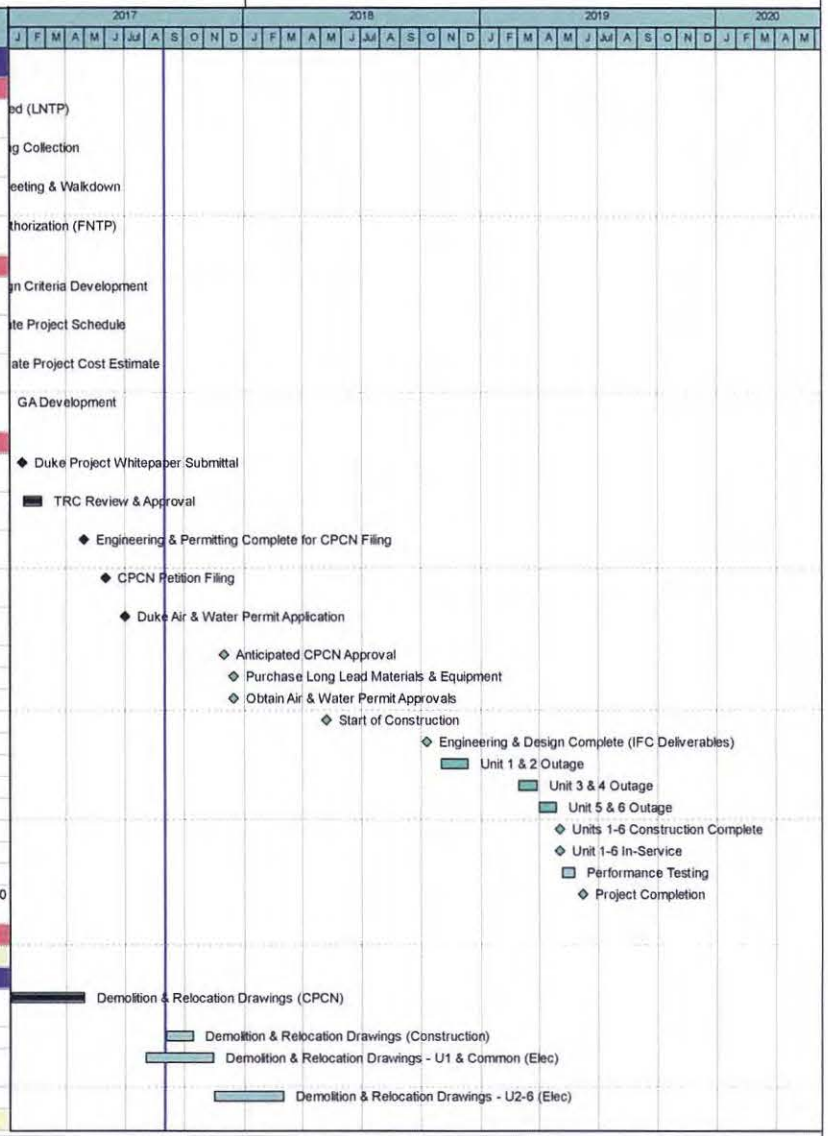
[1] Case No. 2017-00186, *The Application for Duke Energy Kentucky, Inc., for a Certificate of Public Convenience and Necessity for Construction of a Number 2 Distillate Fuel Oil System at the Company's Woodsdale Natural Gas-Fired Generating Station* (filed June 1, 2017).

Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	DUR	Start	Finish	Predecessors
Woodsdale Fuel Oil System Installation		735.0d	28-Jul-16 A	07-Jun-19	
Project Initiation		35.0d	28-Jul-16 A	16-Sep-16 A	
MS00	Project Authorized (LNTP)	0.0d		28-Jul-16 A	
MS02	Data & Drawing Collection	10.0d	01-Aug-16 A	12-Aug-16 A	MS00
MS04	Site Kickoff Meeting & Walkdown	0.0d		15-Aug-16 A	MS02
MS06	Project Authorization (FNTP)	0.0d		16-Sep-16 A	P1000.10
BOP Engineering & Design (LNTP)		71.0d	15-Sep-16 A	27-Dec-16 A	
LNTP.10	Design Criteria Development	33.0d	15-Sep-16 A	01-Nov-16 A	MS02
LNTP.40	Update Project Schedule	6.0d	26-Oct-16 A	02-Nov-16 A	LNTP.10
LNTP.30	Update Project Cost Estimate	16.0d	21-Oct-16 A	11-Nov-16 A	LNTP.10
LNTP.20	GA Development	41.0d	27-Oct-16 A	27-Dec-16 A	LNTP.10
Major Project Milestones		613.0d	23-Jan-17 A	07-Jun-19	
MS10	Duke Project Whitepaper Submittal	0.0d		23-Jan-17 A	
MS13	TRC Review & Approval	20.0d	25-Jan-17 A	21-Feb-17 A	
MS16	Engineering & Permitting Complete for CPCN Filing	0.0d		27-Apr-17 A	
MS17	CPCN Petition Filing	0.0d		31-May-17 A	
MS15	Duke Air & Water Permit Application	0.0d		30-Jun-17 A	
MS18	Anticipated CPCN Approval	0.0d		01-Dec-17*	
MS19	Purchase Long Lead Materials & Equipment	0.0d		15-Dec-17*	MS18, P1000.60, P1200.30, P2300.30
MS20	Obtain Air & Water Permit Approvals	0.0d		15-Dec-17*	
MS21	Start of Construction	0.0d	07-May-18*		P2200.65, P2100.65, MS20
MS22	Engineering & Design Complete (IFC Deliverables)	0.0d		09-Oct-18*	M1600.15, M1800.60, C3400.60, E2800.10
MS23.1	Unit 1 & 2 Outage	30.0d	01-Nov-18*	12-Dec-18	P2200.72
MS23.2	Unit 3 & 4 Outage	20.0d	01-Mar-19*	28-Mar-19	MS23.1
MS23.3	Unit 5 & 6 Outage	20.0d	01-Apr-19*	26-Apr-19	P2200.81, MS23.2
MS24	Units 1-6 Construction Complete	0.0d		03-May-19*	P2200.88, P2100.88
MS25	Unit 1-6 In-Service	0.0d		03-May-19*	P2200.90
MS30	Performance Testing	15.0d	06-May-19	24-May-19	P2200.78, P2200.82, P2200.90
MS50	Project Completion	0.0d		07-Jun-19	MS30, G1200, X2000, X2100, X2200, X2300, X2400
BOP Engineering & Design (FNTP)		452.0d	06-Jan-17 A	09-Oct-18	
General Engineering		294.0d	06-Jan-17 A	01-Mar-18	
Demo & Relocation Dwgs		294.0d	06-Jan-17 A	01-Mar-18	
G1000.10	Demolition & Relocation Drawings (CPCN)	80.0d	06-Jan-17 A	27-Apr-17 A	MS06, LNTP.20, MS16
G1000.20	Demolition & Relocation Drawings (Construction)	30.0d	01-Sep-17	13-Oct-17*	MS17
G1000.30	Demolition & Relocation Drawings - U1 & Common (Elec)	75.0d	01-Aug-17 A	14-Nov-17	E3000.10
G1000.35	Demolition & Relocation Drawings - U2-6 (Elec)	74.0d	15-Nov-17	01-Mar-18	E3000.10, G1000.30
Civil / Structural Detailed Design		264.0d	03-Apr-17 A	13-Apr-18	



Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

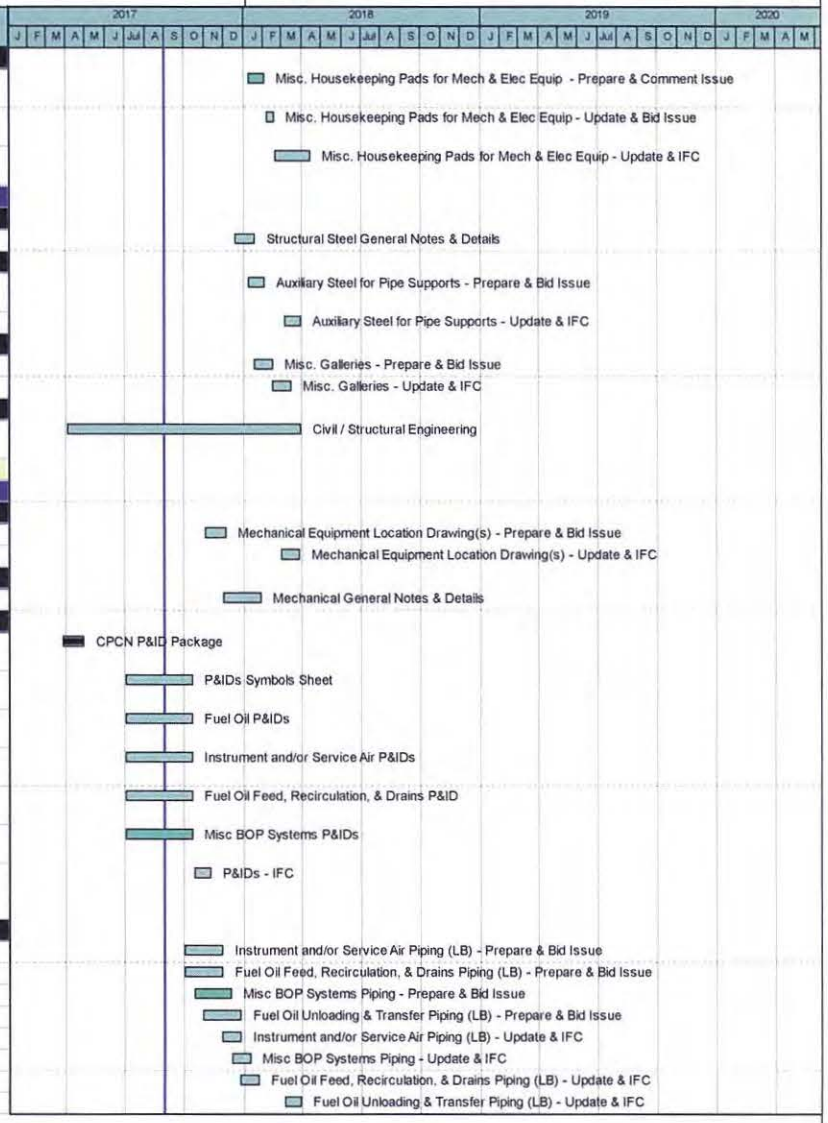
Activity ID	Activity Name	DUR	Start	Finish	Predecessors
	Civil Gen Notes & Details	113.0d	01-Sep-17	12-Feb-18	
C1000.10	Civil General Notes & Details - Prepare & Comment Issue	30.0d	01-Sep-17*	13-Oct-17	MS06, LNTP.10, C1400.10
C1000.30	Civil General Notes & Details - Update & Bid Issue	10.0d	04-Dec-17	15-Dec-17*	C1000.10
C1000.60	Civil General Notes & Details - Update & IFC	10.0d	30-Jan-18	12-Feb-18*	C1000.30
	Sitework and Grading	127.0d	14-Aug-17 A	12-Feb-18	
C1200.10	Sitework, Grading and Containment - Prepare & Comment Issue	45.0d	14-Aug-17 A	16-Oct-17	LNTP.20, LNTP.10, P2400.90
C1200.30	Sitework, Grading and Containment - Update & Bid Issue	10.0d	04-Dec-17	15-Dec-17*	C1200.10
C1200.60	Sitework, Grading and Containment - Update & IFC	10.0d	30-Jan-18	12-Feb-18*	C1200.30
	Roads and Paving	127.0d	14-Aug-17 A	12-Feb-18	
C1400.10	Roads and Paving - Prepare & Comment Issue	45.0d	14-Aug-17 A	16-Oct-17	C1200.10, LNTP.10
C1400.30	Roads and Paving - Update & Bid Issue	10.0d	04-Dec-17	15-Dec-17*	C1400.10
C1400.60	Roads and Paving - Update & IFC	10.0d	30-Jan-18	12-Feb-18*	C1400.30
	SW & OW System Dwgs	127.0d	14-Aug-17 A	12-Feb-18	
C1600.10	Stormwater & Oily Water System Drawings - Prepare & Comment Issue	45.0d	14-Aug-17 A	16-Oct-17	M1400.50, LNTP.10
C1600.30	Stormwater & Oily Water System Drawings - Update & Bid Issue	10.0d	04-Dec-17	15-Dec-17*	C1600.10
C1600.60	Stormwater & Oily Water System Drawings - Update & IFC	10.0d	30-Jan-18	12-Feb-18*	C1600.30
	Arch Dwgs - FO Fwd & Unld Pmps	80.0d	27-Oct-17	20-Feb-18	
C1800.10	Architectural Drawings for Forwarding & Unloading Pumphouse - Prepare & Comment Issue	30.0d	27-Oct-17	11-Dec-17	M1000.10
C1800.30	Architectural Drawings for Forwarding & Unloading Pumphouse - Update & Bid Issue	10.0d	30-Jan-18	12-Feb-18*	C1800.10
C1800.60	Architectural Drawings for Forwarding & Unloading Pumphouse - IFC	6.0d	13-Feb-18	20-Feb-18*	C1800.30
	Concrete Gen Notes & Details	136.0d	01-Aug-17 A	12-Feb-18	
C2200.10	Concrete General Notes & Details - Prepare & Comment Issue	50.0d	01-Aug-17 A	10-Oct-17	MS06, LNTP.10, P2400.90
C2200.30	Concrete General Notes & Details - Update & Bid Issue	10.0d	04-Dec-17	15-Dec-17*	C2200.10
C2200.60	Concrete General Notes & Details - Update & IFC	10.0d	30-Jan-18	12-Feb-18*	C2200.30
	Foundations & Misc. Equipment Pads	142.0d	25-Sep-17	13-Apr-18	
	Fdn & Cntmnt -FO Storage Tnks	99.0d	02-Oct-17	20-Feb-18	
C2400.10	Foundation & Containment for Fuel Storage Tanks - Prepare & Comment Issue	31.0d	02-Oct-17	13-Nov-17*	M2400.20, P2400.90
C2400.30	Foundation & Containment for Fuel Storage Tanks - Update & Bid Issue	20.0d	17-Nov-17	18-Dec-17*	M2400.20, C2400.10, P2400.90, C2400.10
C2400.60	Foundation & Containment for Fuel Storage Tanks - Update & IFC	19.0d	25-Jan-18	20-Feb-18	C2400.30, P1200.68, C2400.30
	Fdn & Cntmnt-FO Unld&Fwd Pmps	95.0d	27-Oct-17	13-Mar-18	
C2600.10	Foundation & Containment for Fuel Unloading / Forwarding Pumps - Prepare & Comment Issue	20.0d	27-Oct-17	27-Nov-17	C1800.10
C2600.30	Foundation & Containment for Fuel Unloading / Forwarding Pumps - Update & Bid Issue	15.0d	28-Nov-17	18-Dec-17	C1800.10, C2600.10
C2600.60	Foundation & Containment for Fuel Unloading / Forwarding Pumps - Update & IFC	40.0d	17-Jan-18	13-Mar-18	C2600.30, P1400.68
	Fdns & Sumps-Truck Unloading	119.0d	25-Sep-17	13-Mar-18	
C2800.10	Foundations & Sumps for Truck Unloading - Prepare & Comment Issue	30.0d	25-Sep-17*	03-Nov-17	C1400.10
C2800.30	Foundations & Sumps for Truck Unloading - Update & Bid Issue	20.0d	06-Nov-17	05-Dec-17	C1400.10, C2800.10
C2800.60	Foundations & Sumps for Truck Unloading - Update & IFC	40.0d	17-Jan-18	13-Mar-18	C2800.30, P1400.68
	Fdns Equipment Bldg	119.0d	25-Sep-17	13-Mar-18	
C2900.10	Foundations Equipment Bldg - Prepare & Comment Issue	30.0d	25-Sep-17*	03-Nov-17	C1400.10
C2900.30	Foundations Equipment Bldg - Update & Bid Issue	20.0d	06-Nov-17	05-Dec-17	C1400.10, C2900.10
C2900.60	Foundations Equipment Bldg - Update & IFC	40.0d	17-Jan-18	13-Mar-18	C2900.30, P1400.68

Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	DUR	Start	Finish	Predecessors
	Misc Conc Pads - Mech & Elec E	70.0d	08-Jan-18	13-Apr-18	
C3000.10	Misc. Housekeeping Pads for Mech & Elec Equip - Prepare & Comment Issue	20.0d	08-Jan-18	02-Feb-18	M1800.20, M1800.50
C3000.30	Misc. Housekeeping Pads for Mech & Elec Equip - Update & Bid Issue	10.0d	05-Feb-18	16-Feb-18	E1800.20, M1800.20, M1800.50, C3000.10
C3000.60	Misc. Housekeeping Pads for Mech & Elec Equip - Update & IFC	40.0d	19-Feb-18	13-Apr-18	M1800.50, M1800.60, C3000.30, E1800.20, P1400.68
	Structural/Architectural Work	254.0d	03-Apr-17 A	30-Mar-18	
	Steel Gen Notes & Details	20.0d	20-Dec-17	17-Jan-18	
C3200.10	Structural Steel General Notes & Details	20.0d	20-Dec-17	17-Jan-18	M1800.10
	Aux Steel - Pipe Sppts	60.0d	08-Jan-18	30-Mar-18	
C3400.30	Auxiliary Steel for Pipe Supports - Prepare & Bid Issue	20.0d	08-Jan-18	02-Feb-18	M1800.10, M1800.50, M1800.30, M1800.20
C3400.60	Auxiliary Steel for Pipe Supports - Update & IFC	20.0d	05-Mar-18	30-Mar-18	C3400.30, M1800.60
	Misc Galleries	40.0d	18-Jan-18	14-Mar-18	
C3600.30	Misc. Galleries - Prepare & Bid Issue	20.0d	18-Jan-18	14-Feb-18	C3200.10
C3600.60	Misc. Galleries - Update & IFC	20.0d	15-Feb-18	14-Mar-18	C3600.30
	Civil / Struc Engineering	254.0d	03-Apr-17 A	30-Mar-18	
C3800.10	Civil / Structural Engineering	254.0d	03-Apr-17 A	30-Mar-18	
	Mechanical	259.0d	27-Mar-17 A	30-Mar-18	
	Mechanical Detailed Design	259.0d	27-Mar-17 A	30-Mar-18	
	Mech Location Dwgs	100.0d	03-Nov-17	27-Mar-18	
M1000.10	Mechanical Equipment Location Drawing(s) - Prepare & Bid Issue	20.0d	03-Nov-17	04-Dec-17	P1000V.25, P1400.30
M1000.60	Mechanical Equipment Location Drawing(s) - Update & IFC	20.0d	28-Feb-18	27-Mar-18	M1000.10, P1400.68
	Mech Gen Notes & Details	40.0d	01-Dec-17	26-Jan-18	
M1200.10	Mechanical General Notes & Details	40.0d	01-Dec-17	26-Jan-18	MS06, LNTP.20, MS18
	P&IDs & Calculations	162.0d	27-Mar-17 A	10-Nov-17	
M1400.10	CPCN P&ID Package	24.0d	27-Mar-17 A	27-Apr-17 A	P1000V.10, P1000V.12
M1400.20	P&IDs Symbols Sheet	73.0d	03-Jul-17 A	13-Oct-17	LNTP.10, P1000V.25
M1400.30	Fuel Oil P&IDs	73.0d	03-Jul-17 A	13-Oct-17	P1000V.25
M1400.40	Instrument and/or Service Air P&IDs	73.0d	03-Jul-17 A	13-Oct-17	P1000V.25
M1400.50	Fuel Oil Feed, Recirculation, & Drains P&ID	73.0d	03-Jul-17 A	13-Oct-17	P1000V.25
M1400.60	Misc BOP Systems P&IDs	73.0d	03-Jul-17 A	13-Oct-17	P1000V.25
M1400.70	P&IDs - IFC	20.0d	16-Oct-17	10-Nov-17	M1400.10, M1400.20, M1400.30, M1400.40, M1400.50, M1400.60, P1000V.25
	Piping ISOs (LB Only)	127.0d	02-Oct-17	30-Mar-18	
M1600.20	Instrument and/or Service Air Piping (LB) - Prepare & Bid Issue	40.0d	02-Oct-17	28-Nov-17	M1400.40
M1600.30	Fuel Oil Feed, Recirculation, & Drains Piping (LB) - Prepare & Bid Issue	40.0d	02-Oct-17	28-Nov-17	M1400.50
M1600.40	Misc BOP Systems Piping - Prepare & Bid Issue	40.0d	16-Oct-17	12-Dec-17	M1400.60
M1600.10	Fuel Oil Unloading & Transfer Piping (LB) - Prepare & Bid Issue	40.0d	30-Oct-17	27-Dec-17	M1400.30
M1600.25	Instrument and/or Service Air Piping (LB) - Update & IFC	20.0d	29-Nov-17	27-Dec-17	P1000V.50, M1600.20
M1600.45	Misc BOP Systems Piping - Update & IFC	20.0d	13-Dec-17	10-Jan-18	P1000V.50, M1600.40
M1600.35	Fuel Oil Feed, Recirculation, & Drains Piping (LB) - Update & IFC	20.0d	27-Dec-17	23-Jan-18	P1000V.50, P1200.70
M1600.15	Fuel Oil Unloading & Transfer Piping (LB) - Update & IFC	20.0d	05-Mar-18	30-Mar-18	P1200.70, P1400.70, P1000V.60

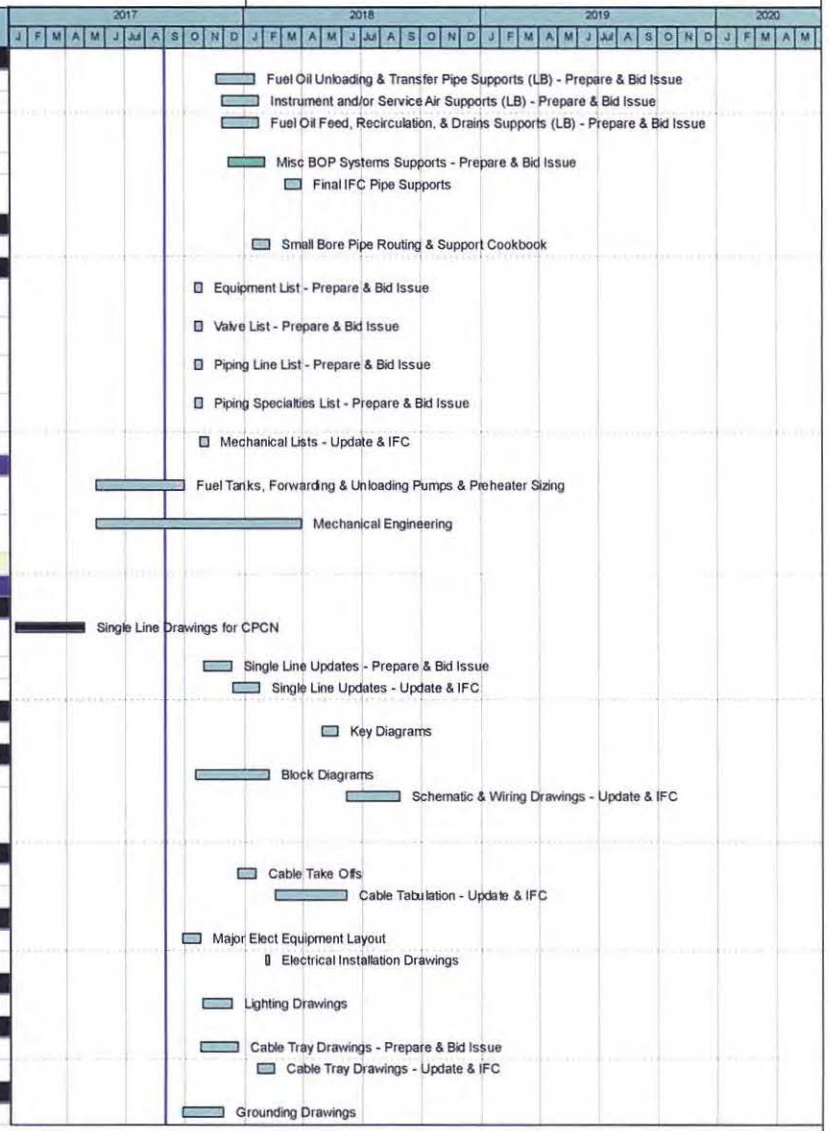


Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	DUR	Start	Finish	Predecessors
	Pipe Sppts (LB Only)	92.0d	20-Nov-17	30-Mar-18	
M1800.10	Fuel Oil Unloading & Transfer Pipe Supports (LB) - Prepare & Bid Issue	40.0d	20-Nov-17	17-Jan-18	M1600.10
M1800.20	Instrument and/or Service Air Supports (LB) - Prepare & Bid Issue	40.0d	29-Nov-17	24-Jan-18	M1600.20
M1800.30	Fuel Oil Feed, Recirculation, & Drains Supports (LB) - Prepare & Bid Issue	40.0d	29-Nov-17	24-Jan-18	M1600.30
M1800.50	Misc BOP Systems Supports - Prepare & Bid Issue	40.0d	08-Dec-17	02-Feb-18	M1600.40
M1800.60	Final IFC Pipe Supports	20.0d	05-Mar-18	30-Mar-18	M1600.15, M1600.25, M1600.35, M1600.45
	SB Pipe & Sppt Cookbook	20.0d	15-Jan-18	09-Feb-18	
M2000.10	Small Bore Pipe Routing & Support Cookbook	20.0d	15-Jan-18	09-Feb-18	P2200.20, P2100.20
	Mech Lists	16.0d	16-Oct-17	06-Nov-17	
M2200.10	Equipment List - Prepare & Bid Issue	10.0d	16-Oct-17	27-Oct-17	M1400.30, M1400.40, M1400.50, M1400.60
M2200.20	Valve List - Prepare & Bid Issue	10.0d	16-Oct-17	27-Oct-17	M1400.30, M1400.40, M1400.50, M1400.60
M2200.30	Piping Line List - Prepare & Bid Issue	10.0d	16-Oct-17	27-Oct-17	M1400.30, M1400.40, M1400.50, M1400.60
M2200.40	Piping Specialties List - Prepare & Bid Issue	10.0d	16-Oct-17	27-Oct-17	M1400.30, M1400.40, M1400.50, M1400.60
M2200.50	Mechanical Lists - Update & IFC	10.0d	24-Oct-17	06-Nov-17	P1000V.55
	Equipment Sizing	222.0d	17-May-17 A	30-Mar-18	
M2400.20	Fuel Tanks, Forwarding & Unloading Pumps & Preheater Sizing	95.0d	17-May-17 A	29-Sep-17	LNTP.10, P1000V.10, P1000V.12
M2400.30	Mechanical Engineering	222.0d	17-May-17 A	30-Mar-18	P1000V.10, P1000V.12
	Electrical / I&C	449.0d	11-Jan-17 A	09-Oct-18	
	Electrical Detail Design	449.0d	11-Jan-17 A	09-Oct-18	
	Single Line Updates	265.0d	11-Jan-17 A	24-Jan-18	
E1000.10	Single Line Drawings for CPCN	77.0d	11-Jan-17 A	27-Apr-17 A	P1000V.10, P1000V.12
E1000.30	Single Line Updates - Prepare & Bid Issue	30.0d	30-Oct-17	12-Dec-17	P1000V.30, M2200.10
E1000.60	Single Line Updates - Update & IFC	30.0d	13-Dec-17	24-Jan-18	P1000V.55, E1000.30
	Key Diagrams	20.0d	30-Apr-18	25-May-18	
E1200.10	Key Diagrams	20.0d	30-Apr-18*	25-May-18	E1400.10, E3000.25
	Schematic & Wiring Dwgs	224.0d	16-Oct-17	28-Aug-18	
E1400.10	Block Diagrams	80.0d	16-Oct-17	07-Feb-18	P1000V.55, E3000.20
E1400.60	Schematic & Wiring Drawings - Update & IFC	60.0d	06-Jun-18	28-Aug-18	P1400.70, P1000V.30, P1000V.55, P2000.70, P2300.70, P2000.68, P2300.70
	Cable Tabulation	120.0d	21-Dec-17	07-Jun-18	
E1600.10	Cable Take Offs	20.0d	21-Dec-17	18-Jan-18	E2200.30
E1600.60	Cable Tabulation - Update & IFC	80.0d	16-Feb-18	07-Jun-18	E3200.10, E2200.60
	Elec Installation Dwgs	94.0d	26-Sep-17	07-Feb-18	
E1800.10	Major Elect Equipment Layout	20.0d	26-Sep-17	23-Oct-17	P1000V.25, P1000V.30
E1800.20	Electrical Installation Drawings	4.0d	02-Feb-18	07-Feb-18	E1400.10, E1800.10, P2300.70
	Lighting Dwgs	30.0d	27-Oct-17	11-Dec-17	
E2000.10	Lighting Drawings	30.0d	27-Oct-17	11-Dec-17	C1800.10, E1800.10
	Cable Tray Dwgs	80.0d	24-Oct-17	15-Feb-18	
E2200.30	Cable Tray Drawings - Prepare & Bid Issue	40.0d	24-Oct-17	20-Dec-17	E1800.10, M1000.10
E2200.60	Cable Tray Drawings - Update & IFC	20.0d	19-Jan-18	15-Feb-18	E1600.10
	Grounding Dwgs	44.0d	26-Sep-17	28-Nov-17	
E2400.10	Grounding Drawings	44.0d	26-Sep-17	28-Nov-17	P1000V.25, P2400.90

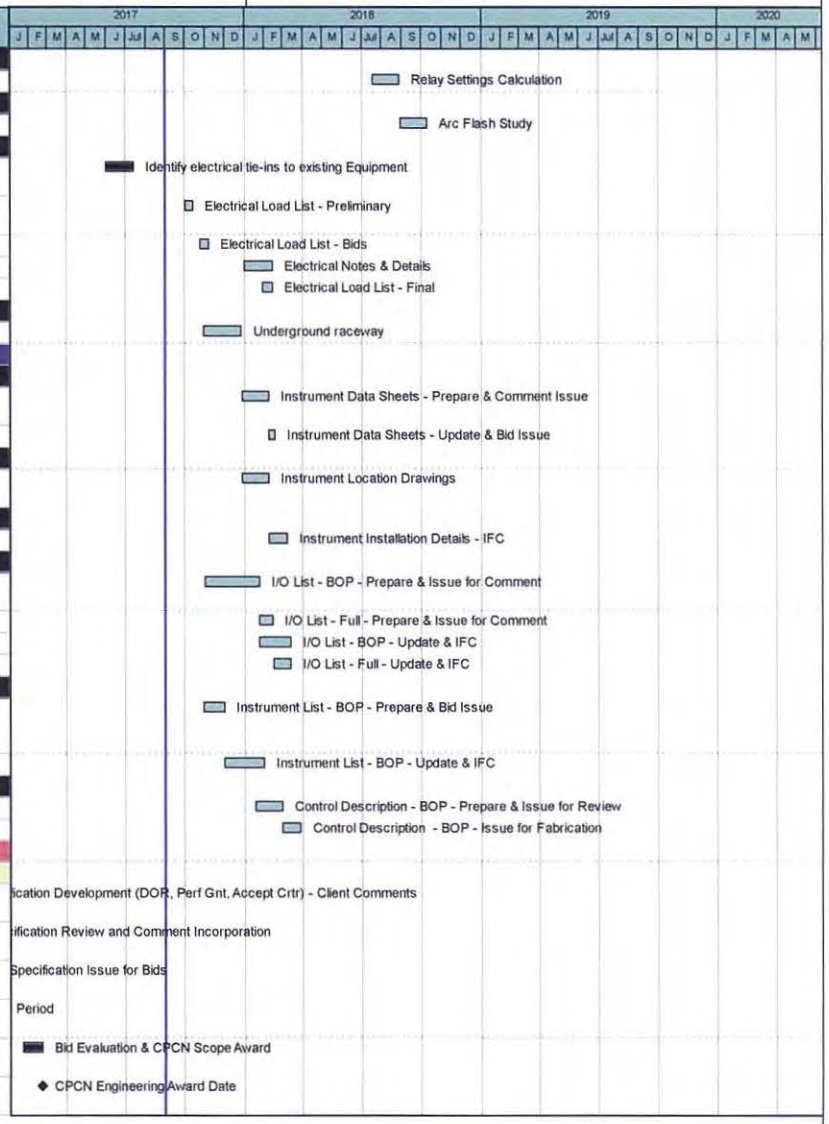


Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	OUR	Start	Finish	Predecessors
	Relay Settings Calculation	30.0d	18-Jul-18	28-Aug-18	
E2600.10	Relay Settings Calculation	30.0d	18-Jul-18	28-Aug-18	E1000.60, E1400.60, P1000V.60
	Arc Flash Study	30.0d	29-Aug-18	09-Oct-18	
E2800.10	Arc Flash Study	30.0d	29-Aug-18	09-Oct-18	E2600.10, E3000.25
	Elec Engineering	179.0d	31-May-17 A	12-Feb-18	
E3000.10	Identify electrical tie-ins to existing Equipment	32.0d	31-May-17 A	14-Jul-17 A	MS06, LNTP.20, MS17
E3000.20	Electrical Load List - Preliminary	10.0d	02-Oct-17	13-Oct-17	M1400.30, M1400.40, M1400.50, M2400.20
E3000.25	Electrical Load List - Bids	10.0d	24-Oct-17	06-Nov-17	P1000V.55, E3000.20
E3000.30	Electrical Notes & Details	30.0d	02-Jan-18	12-Feb-18*	LNTP.10, E3000.26
E3000.26	Electrical Load List - Final	10.0d	30-Jan-18	12-Feb-18	E3000.25, P2300.70
	Elec Undergrounds	40.0d	30-Oct-17	27-Dec-17	
E3200.10	Underground raceway	40.0d	30-Oct-17	27-Dec-17	M2200.10
	I&C Detail Design & Engineering	104.0d	30-Oct-17	27-Mar-18	
	Instr Data Sheets	37.0d	28-Dec-17	16-Feb-18	
J1000.10	Instrument Data Sheets - Prepare & Comment Issue	30.0d	28-Dec-17	07-Feb-18	M1600.20, M1600.10, M1600.30, M1600.40
J1000.30	Instrument Data Sheets - Update & Bid Issue	7.0d	08-Feb-18	16-Feb-18*	J1000.10
	Instr Location Dwgs	30.0d	28-Dec-17	07-Feb-18	
J1200.10	Instrument Location Drawings	30.0d	28-Dec-17	07-Feb-18	M1600.30, M1600.10, M1600.20, M1600.40
	Instr Installation Details	20.0d	08-Feb-18	07-Mar-18	
J1400.10	Instrument Installation Details - IFC	20.0d	08-Feb-18	07-Mar-18	J1200.10
	I/O List	92.0d	01-Nov-17	13-Mar-18	
J1600.30	I/O List - BOP - Prepare & Issue for Comment	57.0d	01-Nov-17	23-Jan-18	M2200.40, M2200.10, P1400.40, E1000.30
J1600.35	I/O List - Full - Prepare & Issue for Comment	15.0d	24-Jan-18	13-Feb-18	P1000V.35, J1600.30, J1800.30
J1600.60	I/O List - BOP - Update & IFC	35.0d	24-Jan-18	13-Mar-18	J1600.30
J1600.65	I/O List - Full - Update & IFC	20.0d	14-Feb-18	13-Mar-18	J1600.35
	Instrument List	64.0d	30-Oct-17	30-Jan-18	
J1800.30	Instrument List - BOP - Prepare & Bid Issue	22.0d	30-Oct-17	30-Nov-17	M2200.40, M2200.10, M1400.20, M1400.30, M1400.40, M1400.50, M1400.60
J1800.60	Instrument List - BOP - Update & IFC	42.0d	01-Dec-17	30-Jan-18	J1800.30
	Control Description	50.0d	17-Jan-18	27-Mar-18	
J1900.30	Control Description - BOP - Prepare & Issue for Review	30.0d	17-Jan-18	27-Feb-18	M1400.50, P1000V.55, J1600.35
J1900.60	Control Description - BOP - Issue for Fabrication	20.0d	28-Feb-18	27-Mar-18	J1900.30
	Procurement	654.0d	24-Oct-16 A	10-May-19	
	Combustion Turbine Vendor	494.0d	24-Oct-16 A	01-Oct-18	
P1000.10	Specification Development (DOR, Perf Gnt, Accept Crtr) - Client Comments	0.0d		24-Oct-16 A	LNTP.10
P1000.20	Specification Review and Comment Incorporation	9.0d	25-Oct-16 A	04-Nov-16 A	P1000.10
P1000.30	GE Specification Issue for Bids	0.0d		07-Nov-16 A	P1000.20
P1000.35	Bid Period	10.0d	08-Nov-16 A	21-Nov-16 A	P1000.30
P1000.60	Bid Evaluation & CPCN Scope Award	23.0d	23-Jan-17 A	22-Feb-17 A	P1000.35
P1000.62	CPCN Engineering Award Date	0.0d		22-Feb-17 A	P1000.60, P1000V.50, P1000V.55

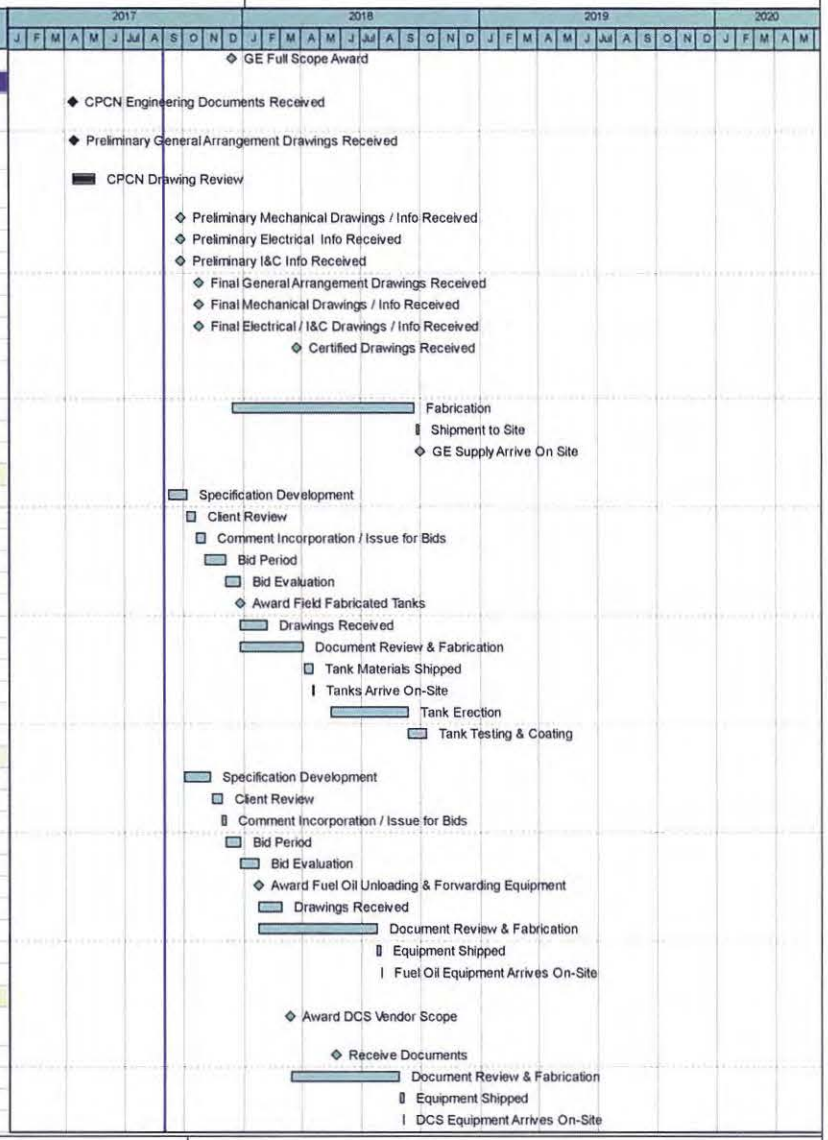


Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	DUR	Start	Finish	Predecessors
P1000.65	GE Full Scope Award	0.0d		15-Dec-17	MS19
Document Review & Fabrication		375.0d	14-Apr-17 A	01-Oct-18	
P1000V.10	CPCN Engineering Documents Received	0.0d		14-Apr-17 A	
P1000V.15	Preliminary General Arrangement Drawings Received	0.0d		14-Apr-17 A	P1000.60
P1000V.12	CPCN Drawing Review	23.0d	14-Apr-17 A	17-May-17 A	P1000V.10
P1000V.[illegible]	Preliminary Mechanical Drawings / Info Received	0.0d		25-Sep-17*	P1000.60
P1000V.[illegible]	Preliminary Electrical Info Received	0.0d		25-Sep-17*	P1000.60
P1000V.[illegible]	Preliminary I&C Info Received	0.0d		25-Sep-17*	P1000.60
P1000V.[illegible]	Final General Arrangement Drawings Received	0.0d		23-Oct-17	P1000.62, P1000V.15
P1000V.[illegible]	Final Mechanical Drawings / Info Received	0.0d		23-Oct-17	P1000V.25
P1000V.[illegible]	Final Electrical / I&C Drawings / Info Received	0.0d		23-Oct-17	P1000V.30, P1000V.35
P1000V.[illegible]	Certified Drawings Received	0.0d		23-Mar-18	P1000.65, P1000V.18
P1000V.18	Full Scope Drawing Review	197.0d	14-Jun-17 A	23-Mar-18	P1000V.12
P1000V.[illegible]	Fabrication	200.0d	15-Dec-17	21-Sep-18	P1000.65
P1000V.[illegible]	Shipment to Site	5.0d	24-Sep-18	28-Sep-18	P1000V.70, P1000.60
P1000V.[illegible]	GE Supply Arrive On Site	0.0d	01-Oct-18		P1000V.80
Field Fabricated Tanks Procurement		280.0d	08-Sep-17	09-Oct-18	
P1200.20	Specification Development	20.0d	08-Sep-17*	05-Oct-17	P1000V.10, P1000V.12
P1200.25	Client Review	10.0d	06-Oct-17	19-Oct-17	P1200.20
P1200.30	Comment Incorporation / Issue for Bids	10.0d	20-Oct-17	02-Nov-17	P1200.25
P1200.35	Bid Period	20.0d	03-Nov-17	04-Dec-17	P1200.30
P1200.40	Bid Evaluation	15.0d	05-Dec-17	26-Dec-17	P1200.35
P1200.60	Award Field Fabricated Tanks	0.0d		26-Dec-17	P1200.40, MS17, MS19
P1200.68	Drawings Received	30.0d	27-Dec-17	06-Feb-18	P1200.60
P1200.70	Document Review & Fabrication	70.0d	27-Dec-17	03-Apr-18	P1200.60, P1200.68
P1200.75	Tank Materials Shipped	10.0d	04-Apr-18	17-Apr-18	P1200.70, C2600.60, P2100.65
P1200.80	Tanks Arrive On-Site	1.0d	18-Apr-18	18-Apr-18	P1200.75
P1200.85	Tank Erection	85.0d	16-May-18	11-Sep-18	P1200.80, P2100.74
P1200.90	Tank Testing & Coating	20.0d	12-Sep-18	09-Oct-18	P1200.85
Fuel Oil Unloading & Forwarding Equipment Procurement		215.0d	02-Oct-17	01-Aug-18	
P1400.20	Specification Development	30.0d	02-Oct-17	10-Nov-17	M2400.20
P1400.25	Client Review	10.0d	13-Nov-17	28-Nov-17	P1400.20
P1400.30	Comment Incorporation / Issue for Bids	4.0d	29-Nov-17	04-Dec-17	P1400.25
P1400.35	Bid Period	15.0d	05-Dec-17	26-Dec-17	P1400.30
P1400.40	Bid Evaluation	20.0d	27-Dec-17	23-Jan-18	P1400.35, MS18
P1400.60	Award Fuel Oil Unloading & Forwarding Equipment	0.0d		23-Jan-18	P1400.40
P1400.68	Drawings Received	25.0d	24-Jan-18	27-Feb-18	P1400.60
P1400.70	Document Review & Fabrication	130.0d	24-Jan-18	24-Jul-18	P1400.60, P1400.68
P1400.75	Equipment Shipped	5.0d	25-Jul-18	31-Jul-18	P1400.70
P1400.80	Fuel Oil Equipment Arrives On-Site	1.0d	01-Aug-18	01-Aug-18	P1400.75
DCS Work (Emerson)		145.0d	13-Mar-18	02-Oct-18	
P2000.60	Award DCS Vendor Scope	0.0d		13-Mar-18	J1600.65, J1600.60, J1800.60, G1000.30, M1400.50, P1000V.55, G1000.35
P2000.68	Receive Documents	0.0d		22-May-18	P2000.60
P2000.70	Document Review & Fabrication	120.0d	14-Mar-18	28-Aug-18	P2000.60, J1900.60
P2000.75	Equipment Shipped	5.0d	29-Aug-18	04-Sep-18	P2000.70, P2000.68
P2000.80	DCS Equipment Arrives On-Site	1.0d	04-Sep-18	04-Sep-18	P2000.75



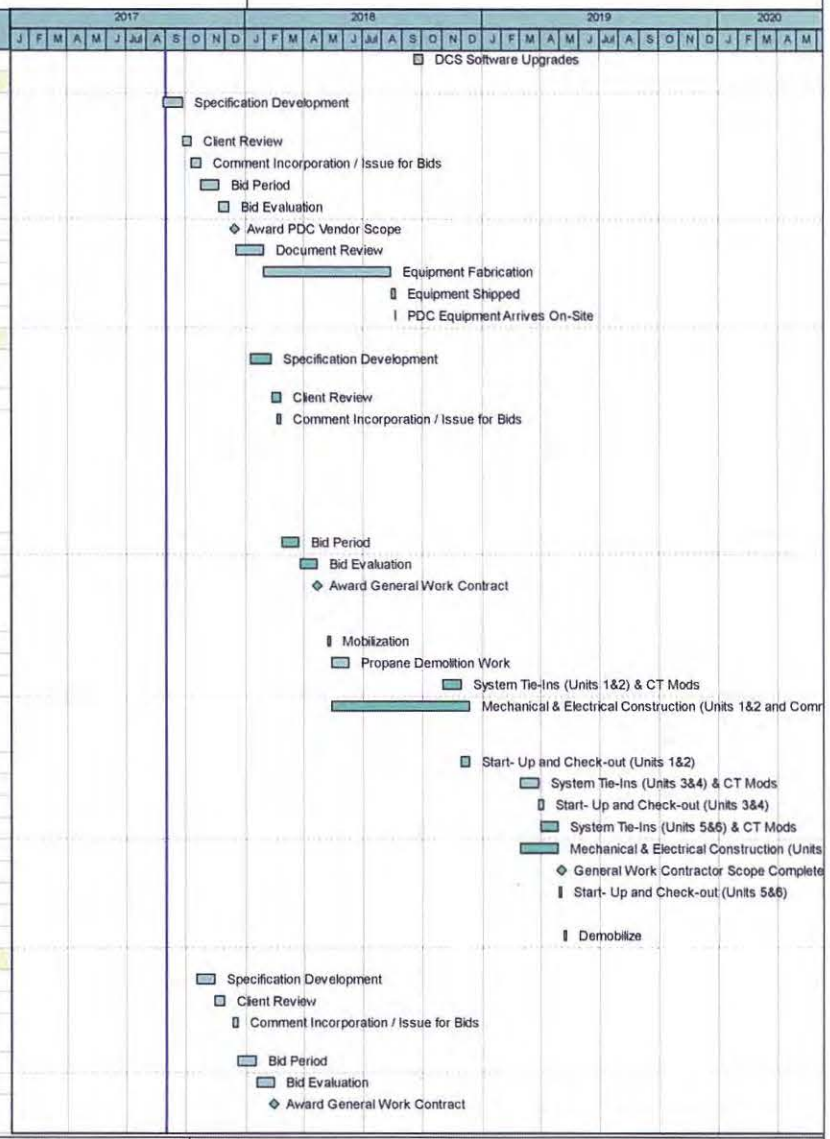
DD: 01-Sep-17

Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	DUR	Start	Finish	Predecessors
P2000.85	DCS Software Upgrades	10.0d	19-Sep-18	02-Oct-18	P2000.75
PDC Specification		252.0d	28-Aug-17 A	20-Aug-18	
P2300.20	Specification Development	20.0d	28-Aug-17 A	25-Sep-17	
P2300.25	Client Review	10.0d	26-Sep-17	09-Oct-17	P2300.20
P2300.30	Comment Incorporation / Issue for Bids	10.0d	10-Oct-17	23-Oct-17	P2300.25
P2300.35	Bid Period	20.0d	24-Oct-17	20-Nov-17	P2300.30
P2300.40	Bid Evaluation	10.0d	21-Nov-17	06-Dec-17	P2300.35
P2300.60	Award PDC Vendor Scope	0.0d		15-Dec-17*	P2300.40, MS19, E3000.25
P2300.70	Document Review	30.0d	18-Dec-17	29-Jan-18	P2300.60
P2300.72	Equipment Fabrication	140.0d	30-Jan-18	13-Aug-18	P2300.70
P2300.75	Equipment Shipped	5.0d	14-Aug-18	20-Aug-18	P2300.72
P2300.80	PDC Equipment Arrives On-Site	1.0d	20-Aug-18	20-Aug-18	P2300.75
General Work Contract		350.0d	08-Jan-18	10-May-19	
P2200.20	Specification Development	25.0d	08-Jan-18	09-Feb-18	M1600.10, M1600.30, C2900.10, C3000.10, C2800.10, C2600.10, J1000.10
P2200.25	Client Review	10.0d	12-Feb-18	23-Feb-18	P2200.20
P2200.30	Comment Incorporation / Issue for Bids	5.0d	19-Feb-18	23-Feb-18	P2200.25, C3000.30, E2200.30, M2000.10, E1600.10, C3600.30, C3200.10, C3400.30, E3000.30, G1000.20, G1000.30, M1200.10, M2200.20, M2200.30, M2200.50, P1000V.40, C2200.30, C1600.30, C1400.30, C1200.30, C1000.30, C2600.30, C2800.30, C2900.30, J1000.30, E1000.60
P2200.35	Bid Period	20.0d	26-Feb-18	23-Mar-18	P2200.30
P2200.40	Bid Evaluation	20.0d	26-Mar-18	20-Apr-18	P2200.35
P2200.60	Award General Work Contract	0.0d		20-Apr-18	P2200.40, C2600.60, M1400.70, C3600.60, C3000.60, C3800.10, M2400.30, E2000.10, J1400.10, C2800.60, C2900.60, M1000.60
P2200.65	Mobilization	5.0d	07-May-18	11-May-18	P2200.40, P2200.60
P2200.70	Propane Demolition Work	20.0d	14-May-18	08-Jun-18	P2200.65
P2200.76	System Tie-Ins (Units 1&2) & CT Mods	20.0d	01-Nov-18*	28-Nov-18	P1200.90, P1000V.90, P2000.85
P2200.72	Mechanical & Electrical Construction (Units 1&2 and Common)	153.0d	14-May-18	12-Dec-18	P2200.65, C1200.10, C1400.10, P2300.80, P2200.70, P2200.78, E1200.10, E1600.60, P1400.80, P2000.80, E2800.10
P2200.78	Start- Up and Check-out (Units 1&2)	10.0d	29-Nov-18	12-Dec-18	P2200.76
P2200.80	System Tie-Ins (Units 3&4) & CT Mods	20.0d	01-Mar-19	28-Mar-19	MS23.2
P2200.82	Start- Up and Check-out (Units 3&4)	5.0d	29-Mar-19	04-Apr-19	P2200.80
P2200.86	System Tie-Ins (Units 5&6) & CT Mods	20.0d	01-Apr-19	26-Apr-19	MS23.3
P2200.81	Mechanical & Electrical Construction (Units 3 - 6)	41.0d	01-Mar-19	26-Apr-19	P2200.72, MS23.2
P2200.88	General Work Contractor Scope Complete	0.0d		03-May-19	P2200.90
P2200.90	Start- Up and Check-out (Units 5&6)	5.0d	29-Apr-19	03-May-19	P2200.86, P2200.99, P2200.86
P2200.99	Document Review / GWC Off Site	255.0d	14-May-18	03-May-19	P2200.65
P2200.92	Demobilize	5.0d	06-May-19	10-May-19	P2200.88
Civil/UG Work Spec		166.0d	17-Oct-17	08-Jun-18	
P2100.20	Specification Development	20.0d	17-Oct-17	13-Nov-17	C1600.10, C2400.10
P2100.25	Client Review	10.0d	14-Nov-17	29-Nov-17	P2100.20
P2100.30	Comment Incorporation / Issue for Bids	5.0d	12-Dec-17	18-Dec-17	P2100.25, C2400.30, C1600.10, E2400.10, G1000.20
P2100.35	Bid Period	20.0d	19-Dec-17	16-Jan-18	P2100.30
P2100.40	Bid Evaluation	20.0d	17-Jan-18	13-Feb-18	P2100.35
P2100.60	Award General Work Contract	0.0d		13-Feb-18	P2100.40, C1000.60, C2200.10, C2200.60, C1600.60, C1200.60, C1400.60, C1800.30



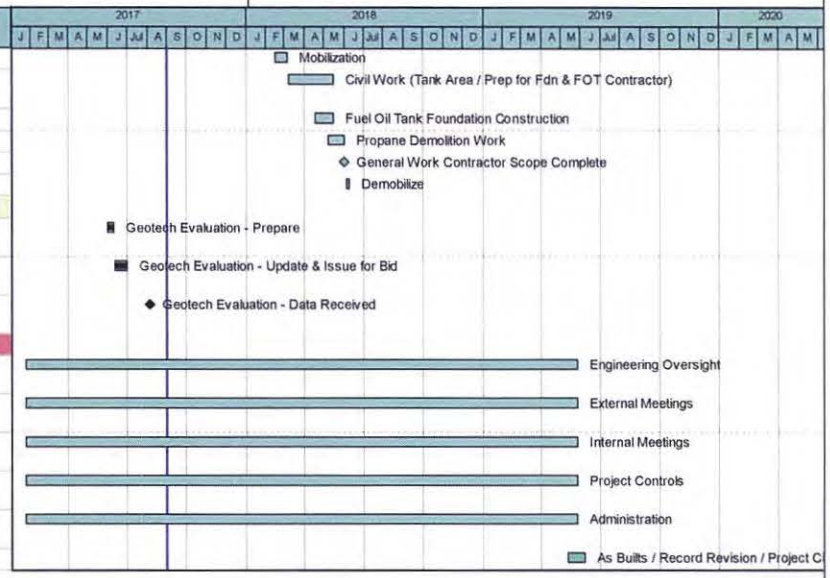
DD: 01-Sep-17

Woodsdale Fuel Oil System Installation

Duke Energy
Woodsdale Fuel Oil System

22-Sep-17 15:53

Activity ID	Activity Name	DUR	Start	Finish	Predecessors
P2100.65	Mobilization	15.0d	14-Feb-18	06-Mar-18	C2400.60, P2100.60
P2100.72	Civil Work (Tank Area / Prep for Fdn & FOT Contractor)	50.0d	07-Mar-18	15-May-18	P2100.65, C1200.10, C1400.10, C1800.60, C2400.60
P2100.74	Fuel Oil Tank Foundation Construction	20.0d	18-Apr-18	15-May-18	P2100.72
P2100.70	Propane Demolition Work	20.0d	07-May-18	01-Jun-18	P2100.65, MS21
P2100.88	General Work Contractor Scope Complete	0.0d		01-Jun-18	P2100.74, P2100.70
P2100.92	Demobilize	5.0d	04-Jun-18	08-Jun-18	P2100.88, P2100.88
Geotech Spec		46.0d	01-Jun-17 A	04-Aug-17 A	
P2400.20	Geotech Evaluation - Prepare	7.0d	01-Jun-17 A	09-Jun-17 A	
P2400.30	Geotech Evaluation - Update & Issue for Bid	15.0d	12-Jun-17 A	30-Jun-17 A	P2400.20
P2400.90	Geotech Evaluation - Data Received	0.0d		04-Aug-17 A	P2400.30
Project Management		612.0d	25-Jan-17 A	07-Jun-19	
X2000	Engineering Oversight	603.0d	25-Jan-17 A	27-May-19	MS00
X2100	External Meetings	603.0d	25-Jan-17 A	27-May-19	MS00
X2200	Internal Meetings	603.0d	25-Jan-17 A	27-May-19	MS00
X2300	Project Controls	603.0d	25-Jan-17 A	27-May-19	MS00
X2400	Administration	603.0d	25-Jan-17 A	27-May-19	MS00
G1200	As Builts / Record Revision / Project Closeout	20.0d	13-May-19	07-Jun-19	P2200.92, P2100.92



DUKE ENERGY KENTUCKY, INC.
CASE NO. 2017-00321
Operations and Maintenance cost

Account	Description	2016 Jan Thru Dec	Base Period Dec 2016 Nov 2017	PJM Year June 2019 May 2020
546000	Suprvsn and Enginring-CT Oper	387,652	348,132	152,415
548100	Generation Expenses-Other CT	6,218	15,102	-
548200	Prime Movers - Generators- CT	266,075	322,237	406,400
549000	Misc-Power Generation Expenses	1,036,079	867,295	519,507
551000	Suprvsn and Enginring-CT Maint	43,717	211,253	92,798
552000	Maintenance of Structures-CT	458,636	368,286	225,292
553000	Maint-Gentg and Elect Equip-CT	2,545,942	3,654,976	1,184,813
554000	Misc Power Generation Plant-CT	188,372	207,250	86,647
Total		4,932,691	5,994,531	2,667,872

Note : PJM year has forecast data June through Dec 2019. 2020 is estimated based on a 1% increase over the prior year.
Amounts represent costs included in other production expense only.
Costs in 2016 and 2017 are higher than the PJM Planning year 2019/2020 because of major outages in those years.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-078

REQUEST:

Refer to the Direct Testimony of William Don Wathen, Jr. ("Wathen Testimony"), page 9. Explain how Duke Kentucky intends to recover cost from the advanced metering infrastructure for its gas meters.

RESPONSE:

The Company will comply with the Commission's May 25, 2017 Order in Case No. 2016-00152. The Commission's Order rejected the stipulated provision to file an application for a natural gas AMI cost/benefit tracking mechanism and instead directed that "Duke Kentucky should include all of the costs and benefits associated with the gas metering infrastructure portion of the AMI project in its next gas base rate case." As such, the test year revenue requirement for the next gas base rate case will reflect the implementation of advanced metering.

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-079

REQUEST:

Refer to the Wathen Testimony, pages 14-16. Recalculate the Rider PSM for 2015, 2016, and to date for 2017 incorporating the changes proposed in the instant matter by Duke Kentucky. Provide the actual Rider PSM calculations for 2015, 2016, and to date 2017.

RESPONSE:

See STAFF-DR-02-079 Attachment.

PERSON RESPONSIBLE: William Don Wathen, Jr.

DUKE ENERGY KENTUCKY, Inc.
Current Rider PSM vs. Proposed Rider PSM

KyPSC Case No. 2017-00321
STAFF-DR-01-079 Attachment
Page 1 of 1

Line No.	Description		2015 Original Total	2015 Proposed Total	2015 Variance	2016 Original Total	2016 Proposed Total	2016 Variance	YTD September 2017 Original Total	YTD September 2017 Proposed Total	YTD September 2017 Variance
1	**Off-System Sales Revenue**										
2	Asset Energy	(+)	$ 26,911,428	$ 26,911,428	$ -	$ 7,630,073	$ 7,630,073	$ -	$ 11,623,692	$ 11,623,692	$ -
3	Non-Asset Energy	(+)	-	-	-	-	-	-	-	-	-
4	Bilateral Sales	(+)	-	-	-	-	-	-	-	-	-
5	Hedges	(+)	(362,908)	(362,908)	-	(1,119)	(1,119)	-	(11,120)	(11,120)	-
6	PJM Bal & DA Oper Reserve Credits	(+)	1,161,014	1,161,014	-	753,737	753,737	-	407,446	407,446	-
7	***Fuel Related RTO Costs and Credits***	(+)	-	(136,309)	(136,309)	-	10,400	10,400	-	7,282	7,282
8	***Non-Fuel Related RTO Costs and Credits***	(+)	-	2,462,763	2,462,763	-	2,092,177	2,092,177	-	2,079,102	2,079,102
9	Capacity	(+)	-	-	-	-	-	-	-	-	-
10	Ancillary Services Market	(+)	1,625,407	-	(1,625,407)	1,757,822	-	(1,757,822)	1,127,416	-	(1,127,416)
11	Sub-Total Revenues		$ 29,334,941	$ 30,035,988	$ 701,047	$ 10,140,513	$ 10,485,268	$ 344,755	$ 13,147,434	$ 14,106,402	$ 958,968
12											
13	**Variable Costs Allocable to Off-System Sales**										
14	Bilateral Purchases	(+)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Non-Native Fuel Cost	(+)	23,449,851	23,449,851	-	7,317,536	7,317,536	-	10,006,826	10,006,826	-
16	Variable O&M Cost	(+)	1,823,963	1,823,963	-	646,418	646,418	-	1,017,243	1,017,243	-
17	SO_2 Cost	(+)	1,251	1,251	-	56	56	-	50	50	-
18	NO_x Cost	(+)	56,620	56,620	-	3,884	3,884	-	1,382	1,382	-
19	PJM and Other Costs	(+)	121,237	-	(121,237)	46,310	-	(46,310)	64,708	-	(64,708)
20	(Gain)/Losss on Sale of Fuel	(+)	-	-	-	-	-	-	-	-	-
21	Sub-Total Expenses		$ 25,452,922	$ 25,331,685	$ (121,237)	$ 8,014,204	$ 7,967,894	$ (46,310)	$ 11,090,209	$ 11,025,501	$ (64,708)
22	Total Off-System Sales Margin (Line 11 - Line 21)	(+)	$ 3,882,019	$ 4,704,303	$ 822,284	$ 2,126,309	$ 2,517,374	$ 391,065	$ 2,057,225	$ 3,080,901	$ 1,023,676
23	Allocated to Customers (guaranteed 100% of first $1.0 million)	(-)	$ 1,000,000			$ 1,000,000			$ 1,000,000		
24	Sub-Total	(+)	$ 2,882,019			$ 1,126,309			$ 1,057,225		
25	Net Margins on Capacity Transactions Allocated to Customers	(+)	$ 6,922,952	$ 6,922,952	$ -	$ 2,533,788	$ 2,533,788	$ -	$ 1,620,471	$ 1,620,471	$ -
26	Percentage Allocated to Customers (75% of margins > $1.0 million)		75.00%			75.00%			75.00%		
27	Remainder Allocated to Customers ((Line 24 + Line 25) x Line 26)		$ 7,353,728			$ 2,745,073			$ 2,008,272		
28	Total Allocated to Customers (Line 23 + Line 27)	(+)	$ 8,353,728			$ 3,745,073			$ 3,008,272		
29	Net Margins on Sales of Emission Allowances	(+)	$ 8,051	$ -	(8,051)	$ -	$ -	$ -	$ 23	$ -	(23)
30	***Net Proceeds from the Sale of Renewable Energy Credits***	(+)	-	-		-	-		-	-	
31	Total			$ 11,627,255	$ 814,233		$ 5,051,162	$ 391,065		$ 4,701,372	$ 1,023,653
32	***Percentage Allocated to Customers (90%)***			90.00%			90.00%			90.00%	
33	Total PSM Credit		$ 8,361,779	$ 10,464,530	2,102,751	3,745,073	$ 4,546,046	800,973	3,008,295	$ 4,231,235	1,222,940
34											
35	Current vs. Proposed PSM Credit			$ 2,102,751			$ 800,973			$ 1,222,940	

STAFF-DR-02-080

REQUEST:

Refer to the Wathen Testimony, pages 18-19.

a. Provide the actual network integration transmission service and Regional Transmission Expansion Plan costs included in the 12 months prior to the base period, the base period, and the forecasted test year.

b. Provide the amounts recovered through base rates for the 12 months prior to the base period, the base period and the forecasted test year.

RESPONSE:

a. See Staff-DR-02-080 Attachment.

b. For the 12 months prior to the base period and for the base period, the amount of NITS costs included in base rates is based on the amount included in the test year used in Case No. 2006-00172, and amounts to $13,256,669.

No RTEP costs have been recovered in base rates for the 12 months prior to the base period.

No RTEP costs will be recovered in base rates for the base period.

The forecasted test period includes $12,964,731 of NITS charges and $4,030,393 of RTEP charges which will be collected in base rates. Assuming the Commission approves the Company's proposal to recover NITS and RTEP costs,

any incremental amount above or below the level in base rates would be recovered or credited in the FTR.

PERSON RESPONSIBLE: William Don Wathen Jr.

Period	Type	NITS	RTEP
12 Months Prior to Base Period			
December 2015	Actual	1,209,103	289,385
January 2016	Actual	1,218,344	287,691
February	Actual	1,139,741	287,691
March	Actual	1,218,344	287,691
April	Actual	1,179,042	288,574
May	Actual	1,218,344	294,997
June	Actual	1,373,134	277,270
July	Actual	1,418,905	293,275
August	Actual	1,418,905	293,275
September	Actual	1,373,134	293,275
October	Actual	1,418,905	293,275
November	Actual	1,373,134	293,275
Base Period			
December 2016	Actual	1,418,905	293,275
January 2017	Actual	1,468,345	298,395
February	Actual	1,326,247	295,098
March	Actual	1,468,345	301,269
April	Actual	1,420,979	298,254
May	Actual	1,468,345	299,944
June	Projected	963,473	354,167 (1)
July	Projected	963,473	354,167 (1)
August	Projected	963,473	354,167 (1)
September	Projected	963,473	354,167 (1)
October	Projected	963,473	354,167 (1)
November	Projected	963,473	354,167 (1)
Forecasted Period			
April 2018	Projected	1,048,083	335,866
May	Projected	1,048,083	335,866
June	Projected	1,048,083	335,866
July	Projected	1,048,083	335,866
August	Projected	1,048,083	335,866
September	Projected	1,048,083	335,866
October	Projected	1,048,083	335,866
November	Projected	1,048,083	335,866
December	Projected	1,048,086	335,866
January 2018	Projected	1,177,327	335,866
February	Projected	1,177,327	335,866
March	Projected	1,177,327	335,867

Footnote:
(1) These are the budgeted amounts for RTEP. However, they were not included in Duke Energy Kentucky's bud

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-081

REQUEST:

Refer to the Wathen Testimony, page 21.

a. What were the amounts paid in 2016 for MISO Transmission Expansion Plan ("MTEP") costs in 2016?

b. Explain whether there is an adjustment to the base period or test period for MTEP costs.

RESPONSE:

a. The amounts paid for MTEP costs in 2016 was the following:

Month	Amount
January 2016	90,603.43
February	90,603.43
March	90,569.07
April	90,569.07
May	90,569.07
June	91,149.43
July	91,149.43
August	91,149.43
September	91,149.43
October	85,092.73
November	85,092.73
December	85,092.73

b. No adjustment to the base period or test period was necessary because MTEP charges are recorded to account 253 since the Company's entire MTEP liability was recorded on its books when it moved to PJM in January 2012.

PERSON RESPONSIBLE: William Don Wathen, Jr.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-082

REQUEST:

Refer to the Wathen Testimony, page 34. Explain how Duke Kentucky arrived at a ten-year amortization period for the East Bend O&M deferral.

RESPONSE:

Please see Response to Staff-DR-02-027(a).

PERSON RESPONSIBLE: William Don Wathen Jr.

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-083

REQUEST:

Refer to the Spanos Testimony, Attachment JJS-1 ("2016 Depreciation Study").

a. Provide a schedule comparing by account the survivor curves, cost of removal percent, salvage value percent, net salvage percent, annual accrual rate, and the composite remaining life for the current depreciation rates with the same information for the proposed depreciation rates shown on pages 55 through 57 of the 2016 Depreciation Study.

b. Refer to page 55 of the 2016 Depreciation Study. Under the heading Common Plant for the current and proposed rates, there is a listing for Erlanger Operations Center.

    1. Explain the large deviation in the current and the proposed depreciation rate for the Erlanger Operations Center.

    2. Provide a schedule of the assets contained in the original cost for the Erlanger Operations Center for the 2005 and 2016 Depreciation Studies.

    3. Are any of the assets at the Erlanger Operations Center leased? If so, through what type of lease?

c. For any net salvage percentages show on pages 55 through 57 of the 2016 Depreciation Study that are not supported by the analysis shown on pages 212

through 262, explain how the net salvage percentage was determined. Include copies of any other studies or analyses used in this determination.

RESPONSE:

a. The attached schedule, ATTACHMENT STAFF-02-083, sets forth a comparison of the current life and salvage parameters to the proposed life and salvage parameters by account as shown in the Depreciation Study.

b. (1) The current rate is based on a 15 year recovery period while the proposed rate is based on an interim survivor curve (90-R1) and life span (retirement date of 2065). At the time of the 2005 study, all assets at Erlanger were expected to be part of a capital lease with a 15 year term. Other differences in the rate are due to the change in plant balance and the age of those new

(2) The table below set forth the assets by year of the Erlanger original cost as of 12/31/2005 Study and this study as of 12/31/2016:

VINTAGE	ORIGINAL COST AT 12/31/2005	ORIGINAL COST AT 12/31/2016
2005	$2,100,000.00	$1,420,054.42
2006		2,087,225.32
2007		2,121,579.00
2008		45,579.78
2009		17,038.06
2010		62,574.42
2012		38,073.81
2015		113,743.46

2016		33,000.00
TOTAL	$2,100,000.00	$5,938,868.27

(3) The primary structure at Erlanger is leased, however, all assets listed in the table above and included in the Depreciation Study are owned as leasehold improvements.

c. The process for determining the net salvage percentage by account is set forth in Part IV of the Depreciation Study. The process describes the combination of the statistical analysis with informed judgment. In the accounts that the statistical analysis set forth on pages 212 through 262 of the Depreciation Study were strong indicators of the recommended net salvage percentage these accounts were listed in Part IV. For the general plant amortization accounts, the net salvage is zero which is consistent with the practice of amortization accounting. The few remaining accounts, judgment which is explained in Part IV was the basis of the estimate which for these accounts was generally zero percent.

PERSON RESPONSIBLE: John Spanos

DUKE ENERGY KENTUCKY

COMPARISON OF CURRENT AND PROPOSED PARAMETERS
RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

		CURRENT				PROPOSED			
	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	COMMON PLANT								
1900	STRUCTURES AND IMPROVEMENTS								
	ERLANGER OPERATIONS CENTER	15-SQ	0	6.78	14.5	90-R1 *	0	1.28	37.9
	KENTUCKY SERVICE BUILDING - 19TH AND AUGUSTINE	100-R1 *	(10)	5.94	6.4	90-R1 *	0	0.43	23.2
	MINOR STRUCTURES	40-R1	0	3.20	25.0	40-R1	(10)	2.81	24.6
1910	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	12.36	5.0	20-SQ	0	5.00	17.0
1911	ELECTRONIC DATA PROCESSING					5-SQ	0	20.00	1.6
1940	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	6.27	9.4	25-SQ	0	4.00	15.8
1970	COMMUNICATION EQUIPMENT	15-SQ	0	13.62	8.5	15-SQ	0	6.67	7.6
1980	MISCELLANEOUS EQUIPMENT	15-SQ	0	6.65	14.5	15-SQ	0	6.67	9.2
	STEAM PRODUCTION PLANT								
3110	STRUCTURES AND IMPROVEMENTS	100-R2.5 *	(3)	1.28	33.3	100-S0.5 *	(17)	2.54	23.4
3120	BOILER PLANT EQUIPMENT	55-S1 *	(11)	2.32	26.9	40-S0.5 *	(17)	2.54	19.5
3123	BOILER PLANT EQUIPMENT - SCR CATALYST	8-S2.5	0	15.28	4.0	10-S2.5	0	5.13	7.4
3140	TURBOGENERATOR UNITS	55-R2.5 *	(8)	2.26	27.4	40-S0.5 *	(17)	2.66	19.2
3150	ACCESSORY ELECTRIC EQUIPMENT	60-R2.5 *	(4)	1.72	27.8	55-R2 *	(17)	2.43	21.2
3160	MISCELLANEOUS POWER PLANT EQUIPMENT	55-S0.5 *	0	2.15	26.3	45-S0 *	(17)	3.64	19.0
	OTHER PRODUCTION PLANT								
3401	RIGHTS OF WAY	40-SQ	0	3.63	26.5	40-SQ	0	3.77	15.5
3410	STRUCTURES AND IMPROVEMENTS	SQUARE *	(3)	2.04	26.5	60-R4 *	(4)	2.53	15.1
3420	FUEL HOLDERS, PRODUCERS AND ACCESSORIES	SQUARE *	(3)	1.75	26.5	55-S2.5 *	(4)	2.17	14.4
3440	GENERATORS	75-R2.5 *	(4)	2.38	24.9	45-R2 *	(4)	3.48	13.8
3450	ACCESSORY ELECTRIC EQUIPMENT	55-S2 *	0	1.80	24.0	40-R2 *	(4)	4.03	13.2
3460	MISCELLANEOUS POWER PLANT EQUIPMENT	50-R2.5 *	0	2.00	22.5	35-S0 *	(4)	4.01	12.2
	TRANSMISSION PLANT								
3501	RIGHTS OF WAY	65-R4	0	1.48	32.8	65-R4	0	1.39	29.6
3520	STRUCTURES AND IMPROVEMENTS	55-R3	(5)	0.41	27.9	65-R2.5	(10)	2.35	39.9
3530	STATION EQUIPMENT	50-R1.5	(5)	2.25	31.0	50-R2	(15)	2.79	31.4
3531	STATION EQUIPMENT - STEP UP					50-R2.5	0	2.36	25.0
3532	STATION EQUIPMENT - MAJOR	50-R3	(10)	2.27	35.7	60-R2.5	(10)	2.10	38.5
3534	STATION EQUIPMENT - STEP UP EQUIPMENT					30-R2.5	0	4.90	18.1
3550	POLES AND FIXTURES	50-R1.5	(25)	2.10	29.9	55-R1.5	(30)	2.39	32.3
3560	OVERHEAD CONDUCTORS AND DEVICES	44-R0.5	(10)	2.31	23.9	50-R1	(30)	2.58	27.1
3561	OVERHEAD CONDUCTORS AND DEVICES - CLEARING/ROW					60-R3	0	2.03	48.9

DUKE ENERGY KENTUCKY

COMPARISON OF CURRENT AND PROPOSED PARAMETERS
RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2016

ACCOUNT		CURRENT				PROPOSED			
		SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	SURVIVOR CURVE	NET SALVAGE PERCENT	ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	DISTRIBUTION PLANT								
3601	RIGHTS OF WAY	70-R3	0	1.07	45.4	70-R3	0	1.18	45.9
3610	STRUCTURES AND IMPROVEMENTS	55-R3	(5)	0.94	35.4	65-R2.5	(10)	2.74	38.8
3620	STATION EQUIPMENT	50-R2	(10)	2.91	28.9	48-R2.5	(15)	2.85	30.0
3622	STATION EQUIPMENT - MAJOR	50-R3	(10)	2.77	31.9	60-R2.5	(10)	1.92	38.6
3640	POLES, TOWERS AND FIXTURES	44-R0.5	(15)	3.29	23.3	52-R0.5	(40)	3.26	27.6
3650	OVERHEAD CONDUCTORS AND DEVICES	46-R1.5	(20)	2.46	28.3	50-O1	(25)	3.56	26.3
3651	OVERHEAD CONDUCTORS AND DEVICES - CLEARING/ROW					60-R2.5	0	2.10	44.8
3660	UNDERGROUND CONDUIT	65-R3	(15)	2.00	48.0	65-S2.5	(20)	2.04	42.8
3670	UNDERGROUND CONDUCTORS AND DEVICES	65-R3	(25)	2.29	45.6	58-R2	(20)	2.62	35.7
3680	LINE TRANSFORMERS	38-R1.5	0	2.42	22.1	45-R0.5	(10)	2.49	23.7
3682	LINE TRANSFORMERS - CUSTOMER	50-R1.5	0	2.00	-	50-R1.5	(10)	0.38	20.8
3691	SERVICES - UNDERGROUND	55-R2	(25)	2.73	35.8	60-R2	(25)	2.54	41.7
3692	SERVICES - OVERHEAD	50-R1	(50)	2.45	29.5	53-R1	(20)	1.87	30.1
3700	METERS	28-S0	0	5.82	12.9	24-L1	(1)	6.32	**
3701	INSTRUMENTATION TRANSFORMERS					24-L1	(1)	11.21	5.7
3702	UoF METERS					15-S2.5	0	7.60	12.8
3712	COMPANY-OWNED OUTDOOR LIGHTING					20-S0.5	0	7.36	13.1
3720	LEASED PROPERTY ON CUSTOMER PREMISES	25-L2	0	-	-	25-L3	0	-	-
3731	STREET LIGHTING - OVERHEAD	30-L1	(5)	0.92	18.5	32-L0.5	(10)	1.22	17.3
3732	STREET LIGHTING - BOULEVARD	30-L1	(5)	3.62	16.6	45-R1.5	(10)	1.49	26.4
3733	STREET LIGHTING - CUSTOMER POLES	33-R1.5	(15)	1.47	20.9	30-L0	(10)	4.88	14.7
	GENERAL PLANT								
3900	STRUCTURES AND IMPROVEMENTS	35-R2.5	(5)	1.77	25.9	35-S1	(5)	5.36	13.9
3910	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	18.56	2.6	20-SQ	0	-	-
3911	ELECTRONIC DATA PROCESSING					5-SQ	0	20.00	2.5
3920	TRANSPORTATION EQUIPMENT					12-S3	0	9.23	10.7
3921	TRANSPORTATION EQUIPMENT - TRAILERS	15-SQ	0	6.53	10.2	18-R2.5	5	4.50	8.2
3940	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	4.14	13.0	25-SQ	0	4.00	19.3
3960	POWER OPERATED EQUIPMENT			-	-	15-L2	0	8.62	6.2
3970	COMMUNICATION EQUIPMENT	15-SQ	0	6.93	2.5	15-SQ	0	6.67	9.3

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-084

REQUEST:

Refer to the Ziolkowski Testimony. Explain any fundamental differences between the filed COSS and the COSS from Duke Kentucky's last rate case, Case No. 2006-00172.

RESPONSE:

Subsequent to the last rate case, the Company made substantial revisions to its COSS model.

- The current COSS model includes all work papers. Even though this increased the number of tabs in the spreadsheet, all work papers can be accessed without opening another file.
- The current COSS model contains tabs that show all subsets of the COSS. For example, moving left to right from tab to tab, the model contains a functional COSS (costs allocated to production, transmission, and distribution). The next few tabs then show the production costs classified as demand, energy, and customer costs. Subsequent tabs show the classified transmission and distribution costs. Following these tabs, the total allocated costs for each rate appear on a separate tab. Finally, the classified costs for each rate are shown on separate tabs.

- The previous COSS model included macros to develop the various reports discussed above. Those macros have been eliminated. The current model includes print macros.

Both the current and previous studies following the guidelines that appear in the NARUC Electric Utility Cost Allocation Manual.

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-085

REQUEST:

Refer to the Ziolkowski Testimony, page 3. The Commission recommended in Case No. 91-370[1] that Duke Kentucky's predecessor in interest, Union Light, Heat and Power Company, should separate distribution plant into primary and secondary components.

a. Provide the primary and secondary line weights from Duke Kentucky's last rate case, Case No. 2006-00172.

b. Refer to the Application, Volume 10, Tab 43, Cost of Service Workpapers, page 7. Provide an explanation if any of the class weights for primary and secondary lines are 3 percent greater or 3 percent less than the weights presented above in Item 86.a.

RESPONSE:

a. See the following table:

[1] Case No. 91-370, *Application of the Union Light, Heat and Power Company to Adjust Electric Rates* (Ky. PSC May 5, 1992).

	PRIMARY LINES	SECONDARY LINES
TOTAL	100.0000000%	100.0000000%
RS	45.8802119%	45.8802153%
DS	27.3462382%	27.3462369%
DS_RTP	0.0259069%	0.0259066%
GSFL	0.1068128%	0.1068101%
EH	0.3609535%	0.3609541%
SP	0.0107121%	0.0107100%
DT_SEC	16.3362737%	16.3362754%
DT_SEC_RTP	0.1806243%	0.1806226%
DT_PRI	7.7987192%	7.7987177%
DT_PRI_RTP	0.3590726%	0.3590733%
DP	0.6738550%	0.6738581%
DP_RTP	0.0000000%	0.0000000%
TT	0.0000000%	0.0000000%
TT_RTP	0.0000000%	0.0000000%
LT	0.9123718%	0.9123717%
OTHER	0.0082480%	0.0082482%

b. N/A

PERSON RESPONSIBLE: James E. Ziolkowski

Duke Energy Kentucky
Case No. 2017-00321
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STAFF-DR-02-086

REQUEST:

Refer to the Ziolkowski Testimony, page 5. Provide the COSS for the Average and Excess and Summer/Non Summer studies.

RESPONSE:

Please see STAFF-DR-02-086 Attachment (a) and (b) provided electronically on CD.

PERSON RESPONSIBLE: Jim Ziolkowski

STAFF-DR-02-086
ATTACHMENT (a) IS
BEING PROVIDED ON CD

STAFF-DR-02-086
ATTACHMENT (b) IS
BEING PROVIDED ON CD

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-087

REQUEST:

Refer to the Application, Volume 10, Tab 53, Cost of Service Workpapers.

a. Refer to page 1. Explain why Duke Kentucky believes a 10 percent decrease of the class subsidization is appropriate.

b. Refer to page 5. Explain the weighted cost factors for the meter.

c. Refer to page 8. Provide an explanation for the weighting factors in column (4).

RESPONSE:

a. The Company chose the ten percent figure because it removes some of the class subsidization while minimizing the rate increase to residential customers.

b. The weighted cost factor is calculated by taking the average meter cost per rate group divided by the residential average meter cost.

c. The weighting factor is determined by the average demand for each rate group in column 3.

Average Demand (Size in KVA)	Weighting Factor (d)
0 - 25	1
26 - 50	1
51 - 100	2
101 - 150	4
>= 151	7

PERSON RESPONSIBLE: Jim Ziolkowski

STAFF-DR-02-088

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 29, Attachment Staff-DR-01-029__-_COSS.xlsx.

a. The following tabs contain #REF! errors. Correct and provide an update to this Excel workbork:

   (1) FR-16(7)(v)-15 RES Classified

   (2) FR-16(7)(v)-16 DS Classified

   (3) FR-16(7)(v)-17 GSFL Classified

   (4) FR-16(7)(v)-18 EH Classified

   (5) FR-16(7)(v)-19 SP Classified

   (6) FR-16(7)(v)-20 DTS Classified

   (7) FR-16(7)(v)-21 DTP Classified

   (8) FR-16(7)(v)-22 DP Classified

   (9) FR-16(7)(v)-23 TT Classified

   (10) FR-16(7)(v)-24 LT Classified

   (11) FR-16(7)(v)-25 OTH Classified

b. Refer to tab FR-16(7)(v)-1 Functional, line no. 20, Total Electric Cost of Service, Production of $263,438,138. Also refer to tab FR-16(7)(v)-2 PROD Classified,

line 20, Total Electric Cost of Service, Total Production of $263,477,907. Reconcile this difference.

RESPONSE:

a. Please see STAFF-DR-02-088 Attachment for the corrected Cost of Service workbook.

b. The difference was caused by the following issues.

    a. Cell F604 from FR-16(7)(v)-1 Functional was not linked to cell F604 of the FR-16(7)(v)-2 PROD Classified tab.

    b. Cells G674 and G720 on the FR-16(7)(v)-1 Functional did not tie to the corresponding cells on the FR-16(7)(v)-2 PROD Classified due to inconsistent formulas between the worksheets.

The corrections are included in STAFF-DR-02-088 Attachment provided on CD.

PERSON RESPONSIBLE: James E. Ziolkowski

STAFF-DR-02-088 ATTACHMENT IS BEING PROVIDED ON CD

STAFF-DR-02-089

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 37, regarding executive salaries and other compensation.

a. Provide the account numbers to which the executives and/or officers' salaries and other compensation were charged.

b. Provide an explanation of the amount and percentage of each of these employees' salaries and associated expenses, which were recorded below the line for ratemaking purposes, along with how the methodology for doing so was determined.

RESPONSE:

Please see, STAFF-DR-02-089 Attachment 1.

PERSON RESPONSIBLE: Jeff Setser

Executives Identified in Response to Staff's First Request, Item 37

Previous Executive Officers

	Name	Employee ID	Title	Last Date in Role
1	B Keith Trent	235408	EVP, Grid Solutions and President, MW and FL Regions	5/31/2015
2	Bill McCollum	144924	Group Executive & Chief Reg Generation Officer	5/1/2007
3	Brett C Carter	253262	SVP, Chief Distribution Officer	8/15/2014
4	Christopher C Rolfe	104835	Group Executive & Chief Administrative Officer	6/1/2009
5	David L Hauser	130270	Group Executive & Chief Financial Officer	7/1/2009
6	James E Mehring	009828	VP, Gas Operations	5/1/2014
	James E Rogers	015661	Chairman, Pres & CEO	6/30/2013
7	James L Turner	017361	Group Executive, Pres & COO of US FEG	1/1/2011
8	Jeana G Sheehan	219433	Interim Chief HR Officer	3/1/2015
9	Jeffrey J Lyash	330533	EVP, Energy Supply	1/1/2013
10	Jim L Stanley	010041	SVP & Chief Distribution Officer	10/1/2012
11	Julia S Janson	041671	State President OH/KY	12/16/2012
12	Lynn J Good	025569	EVP & Chief Financial Officer	6/30/2013
13	Marc Manly	025156	Group Executive & Chief Legal Officer & Corporate Secretary	12/16/2012
14	Patricia K Walker	009050	SVP, OH and KY Gas Operations	6/1/2010
15	Sandra P Meyer	200029	SVP, Power Delivery	6/1/2010
16	Steven K Young	102646	VP, Chief Accounting Officer & Controller	8/5/2013

Response: Question #89

	Name	Employee ID	Period reviewed	Account Numbers Charged	FERC	Below the Line?	Explanation
1	B Keith Trent	235408	For the Period 06/01/2014 through 05/31/2015	238000	238	No	
				242461	242	No	
				804210	184	No	
				804220	184	No	
				920000	920	No	
				926000	926	No	
2	Bill McCollum	144924	Data unavailable	N/A			
3	Brett C Carter	253262	For the Period 08/01/2013 through 08/15/2014	238000	238	No	
				242461	242	No	
				804210	184	No	
				804220	184	No	
				804330	184	No	
				920000	920	No	
				926000	926	No	
4	Christopher C Rolfe	104835	For the Period 06/01/2008 through 06/01/2009	238000	238	No	
				242690	242	No	
				804210	184	No	
				920000	920	No	
				923000	926	No	
5	David L Hauser	130270	For the Period 07/01/2008 through 07/01/2009	238000	238	No	
				242690	242	No	
				804210	184	No	
				920000	920	No	
				923000	926	No	
6	James E Mehring	009828	For the Period 05/01/2013 through 05/01/2014	107000	107	No	

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5	David L Hauser	130270	Group Executive & Chief Financial Officer	7/1/2009
6	James E Mehring	009828	VP, Gas Operations	5/1/2014
	James E Rogers	015661	Chairman, Pres & CEO	6/30/2013
7	James L Turner	017361	Group Executive, Pres & COO of US FEG	1/1/2011
8	Jeana G Sheehan	219433	Interim Chief HR Officer	3/1/2015
9	Jeffrey J Lyash	330533	EVP, Energy Supply	1/1/2013
10	Jim L Stanley	010041	SVP & Chief Distribution Officer	10/1/2012
11	Julia S Janson	041671	State President OH/KY	12/16/2012
12	Lynn J Good	025569	EVP & Chief Financial Officer	6/30/2013
13	Marc Manly	025156	Group Executive & Chief Legal Officer & Corporate Secretary	12/16/2012
14	Patricia K Walker	009050	SVP, OH and KY Gas Operations	6/1/2010
15	Sandra P Meyer	200029	SVP, Power Delivery	6/1/2010
16	Steven K Young	102646	VP, Chief Accounting Officer & Controller	8/5/2013

Response: Question #89

	Name	Employee ID	Period reviewed	Account Numbers Charged	FERC	Below the Line?	Explanation
				186120	186	No	
				238000	238	No	
				242461	242	No	
				804210	184	No	
				804220	184	No	
7	James L Turner	017361	For the Period 01/01/2010 through 01/01/2011	238000	238	No	
				242381	242	No	
				242461	242	No	
				804210	184	No	
				804220	184	No	
				920000	920	No	
				923000	923	No	
8	Jeana G Sheehan	219433	For the Period 03/01/2014 through 03/01/2015	238000	238	No	
				242216	242	No	
				242381	242	No	
				242461	242	No	
				242490	242	No	
				804210	184	No	
				804220	184	No	
				920000	920	No	
				926000	926	No	
9	Jeffrey J Lyash	330533	Data unavailable	N/A			
10	Jim L Stanley	010041	For the Period 10/01/2011 through 10/01/2012	238000	238	No	
				242381	242	No	
				242461	242	No	
				804210	184	No	

Executives Identified in Response to Staff's First Request, Item 37

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6	James E Mehring	009828	VP, Gas Operations	5/1/2014
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10	Jim L Stanley	010041	SVP & Chief Distribution Officer	10/1/2012
11	Julia S Janson	041671	State President OH/KY	12/16/2012
12	Lynn J Good	025569	EVP & Chief Financial Officer	6/30/2013
13	Marc Manly	025156	Group Executive & Chief Legal Officer & Corporate Secretary	12/16/2012
14	Patricia K Walker	009050	SVP, OH and KY Gas Operations	6/1/2010
15	Sandra P Meyer	200029	SVP, Power Delivery	6/1/2010
16	Steven K Young	102646	VP, Chief Accounting Officer & Controller	8/5/2013

Response: Question #89

	Name	Employee ID	Period reviewed	Account Numbers Charged	FERC	Below the Line?	Explanation
				804220	184	No	
				804330	184	No	
				920000	920	No	
11	Julia S Janson	041671	For the Period 12/01/2011 through 12/16/2012	238000	238	No	
				242461	242	No	
				426540	426.5	Yes	Cost of $1,774 was noted as charged to this account
				804210	184	No	
				804220	184	No	
				920000	920	No	
				923000	926	No	
12	Lynn J Good	025569	For the Period 07/01/2012 through 06/30/2013	238000	238	No	
				242461	242	No	
				804220	184	No	
				920000	920	No	
				926000	926	No	
13	Marc Manly	025156	For the Period 12/01/2011 through 12/16/2012	238000	238	No	
				242461	242	No	
				804210	184	No	
				804220	184	No	
				920000	920	No	
				923000	926	No	
14	Patricia K Walker	009050	For the Period 06/01/2009 through 06/01/2010	186120	186	No	
				238000	238	No	
				242381	242	No	
				242461	242	No	
				242490	242	No	

Executives Identified in Response to Staff's First Request, Item 37

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Response: Question #89

	Name	Employee ID	Period reviewed	Account Numbers Charged	FERC	Below the Line?	Explanation
				804220	184	No	
				923000	923	No	
15	Sandra P Meyer	200029	For the Period 06/01/2009 through 06/01/2010	238000	238	No	
				242461	242	No	
				242490	242	No	
				920000	920	No	
				923000	923	No	
				926000	926	No	
				930250	930.2	No	
16	Steven K Young	102646	For the Period 08/01/2012 through 08/05/2013	238000	238	No	
				242461	242	No	
				804210	184	No	
				804220	184	No	
				920000	920	No	
				923000	923	No	

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 33. For the test year, provide the following information at it relates to lobbying activities:

a. The names of each of Duke Kentucky's Kentucky-registered lobbyists.

b. For each of the registered lobbyists, the dollar amount and percentage of the lobbyist's salary, fringe benefits, any incentive pay, and expense reports recorded below the line and any lobbying activities costs reflected in Duke Kentucky's proposed cost of service.

c. The dollar amount of any lobbying activity allocated to Duke Kentucky from Duke Energy or any of its subsidiaries, along with a statement in which these costs are recorded and account numbers where these costs are recorded (above or below the line).

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

a. Duke Kentucky does not directly employ registered lobbyists. Please see Staff's first set of data requests, STAFF-DR-01-062 for the names of Duke Energy Business Services ("DEBS") employees who are registered lobbyists with the Kentucky Legislative Ethics Commission.

b. Please see Confidential STAFF-DR-02-090b Attachment CONFIDENTIAL (being filed under seal of a Petition for Confidential Treatment) for the dollar amount and percentage of the lobbyist's salary, fringe benefits, and incentive pay, and expense reports recorded below the line. There are no lobbying activity costs reflected in Duke Kentucky's proposed cost of service.

c. There are no lobbying activities allocated to Duke Kentucky from Duke Energy or any of its subsidiaries recorded above or below the line.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky, Inc.
Lobbyist Expenses

				Test Year: April 1, 2018 - March 31, 2019				
Registered Lobbyist	FERC Account	Process ID	Operating Unit	% of Salary	Base Salary	Fringe Benefits Allocation	Incentive Pay Allocation	Expense Reports
Patrick Keal	426400	LOBBYKY	OHSK (Kentucky Electric)	41%	[redacted]			
Chuck Session	426400	LOBBYKY	OHSK (Kentucky Electric)	52%				
Total								$20,000.0 (1)

Note: All amounts are recorded below the line to FERC Account 426400 and have not been included in the forecasted test period
(1) Expenses are not budgeted by employee

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-091

REQUEST:

Refer to Duke Kentucky's response to Staff's First Request, Item 50, regarding professional service expense. State whether any expenses for professional services were excluded from the revenue requirement in this proceeding.

RESPONSE:

Yes. As shown on WPD-2.23a, $8,234 of professional service expenses (amounts included in Account 923000 on this workpaper) were excluded from the forecasted test period.

PERSON RESPONSIBLE: Sarah E. Lawler

Duke Energy Kentucky
Case No. 2017-00321
Staff Second Set Data Requests
Date Received: October 26, 2017

STAFF-DR-02-092

REQUEST:

Explain whether Duke Kentucky is considering implementing a prepay program.

RESPONSE:

A voluntary pre-payment program is currently in the early stages of development and specific details pertaining to program structure, customer eligibility, and other terms and conditions for participation are being evaluated. Any pre-payment program offered by Duke Energy Kentucky will be tailored to ensure it complies with regulations, including necessary waivers and/or notices prior to disconnection. The Company is evaluating the possibility of a limited pilot as a potential energy efficiency measure. Duke Energy Kentucky recognizes that Commission approval for a full-scale program deployment may be necessary.

PERSON RESPONSIBLE: Sasha Weintraub