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PUBLIC SERVICE COMMISSION

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April 30, 2020

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VIA E-MAIL TRANSMISSION – PSCED@KY.GOV

Kent A. Chandler
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: **Kentucky Power Company's 2019 Annual Resource Assessment And Related Filings**

Dear Mr. Chandler:

Kentucky Power is making this filing by e-mail transmission in accordance with the Commission's March 16, 2020 Order in Case No. 2020-00085. Accompanying this letter is Kentucky Power Company's 2019 Annual Resource Assessment as directed by the Commission's March 29, 2004 Order in Administrative Case No. 387. It is being filed in accordance with the Commission's October 7, 2005 order closing Administrative Case No. 387 and directing that future Administrative Case No. 387 periodic Annual Resource Assessments be filed annually as a supplement to the Company's Public Service Commission Annual Report.

Also being filed today are:

(a) The Company's motion for confidential treatment with respect to portions of its response to Data Requests Nos. 6 and 9 as part of the 2019 Annual Resource Assessment. It is being filed without a case number in light of the Commission's October 7, 2005 order closing Administrative Case No. 387. The confidential versions of the two responses are being separately made available for upload by the Commission by means of an encrypted file share site in accordance with the Commission's March 24, 2020 Order in Case No. 2020-00085; and

(b) Kentucky Power Company's 2019 FERC Form 1.

A copy of the American Electric Power Company's 2019 Form 10-K and the 2019 Annual Report (Financial Statements) for Kentucky Power were filed separately on April 29, 2020. Kentucky Power Company's 2019 Annual Public Service Commission Utility Financial Report was separately downloaded to the Commission's electronic filing portal on April 28, 2020.

The original data requests required Kentucky Power to provide information concerning the operation of the "AEP-East Power Pool" as part of its periodic filings in accordance with the Commission's March 29, 2004 Order in Administrative Case No. 387. The AEP Interconnection Agreement terminated on January 1, 2014. Because the AEP-East Power Pool no longer exists the requested information regarding the operation AEP-East Power Pool longer exists. Unless the Company is advised to the contrary, it will not address in future filings the 2014 termination of the AEP-East Power Pool, and the resulting absence of responsive information, in connection with these responses.

Please do not hesitate to contact me if you have any questions.

Very truly yours,

Mark R. Overstreet

MRO

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

Kentucky Power Company's 2019 Filing In Response To The Commission's Order In Administrative Case No. 387	)))	Case No. 2020-00___

Kentucky Power Company's Motion for Confidential Treatment

Kentucky Power Company moves the Public Service Commission of Kentucky pursuant 807 KAR 5:001, Section 13 for confidential treatment of portions of: (a) Confidential Attachment 2 to the Company's response to Data Request No. 6; and Confidential Attachment 1 to the Company's response to Data Request No. 9.

1. The information for which confidential treatment is being sought is being filed in accordance with the Commission's Order in Administrative Case No. 387, *A Review Of The Adequacy Of Kentucky's Generation And Transmission System.* By order dated October 7, 2005, the Commission closed Administrative Case No. 387 and directed that the "updated information that is currently required to be filed annually in this case shall be filed as a supplement to the filer's annual report."[1] Accordingly, there is no open proceeding in which Kentucky Power can file this motion for confidential treatment.

2. Pursuant to 807 KAR 5:001, Section 13, Kentucky Power is filing under seal, with the confidential portions highlighted in yellow, those portions of Attachment 2 to its response to Data Request No. 6 and Attachment 1 to its response to Data Request No. 9 for which it is seeking confidential treatment. Consistent with the Commission's March 16, 2020 and March 24, 2020 orders in Case No. 2020-00085, Kentucky Power is transmitting the confidential portions of the

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[1] Order, *A Review Of The Adequacy Of Kentucky's Generation And Transmission System* at 1 Adm. Case No. 387 (Ky. P.S.C. October 7, 2007).

two attachments to the Commission using an encrypted file-share site whereby the Commission may retrieve the confidential material. The originals will be filed in accordance with further orders of the Commission when the Commission's offices re-open to the public. Kentucky Power will notify the Commission when it determines the information for which confidential treatment is sought is no longer confidential.

A. The Requests and the Statutory Standard.

3. The identified portions of the Company's responses to Data Request 6 and Data Request 9 are required to be excluded from the public record and public disclosure. KRS 61.878(1)(c)(1) excludes from the Open Records Act:

> "[r]ecords confidentially disclosed to an agency or required by an agency to be disclosed to it, generally recognized as confidential or proprietary, which if openly disclosed would present an unfair commercial advantage to competitors of the entity that disclosed the records.

This exception applies to the identified portions of Kentucky Power's responses to Data Request No. 6 and Data Request No. 9, as the Commission has previously recognized.[2]

1. Confidential Attachment 2 To The Response To Data Request No. 6.

4. Confidential Attachment 2 to the Company's response to Data Request No. 6 details the specific timing of planned maintenance outages for Kentucky Power's generation units through 2023. The rise of competitive markets such as PJM has placed a premium on generating unit data. Public disclosure of information about unit availability could adversely affect Kentucky Power's

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[2] Order, *in the Matter of: Electronic Omnibus Order Addressing Certain Pending Petitions For Confidential Treatment*, Case No.2019-00418 at Appendix B, p. 10 (Ky. P.S.C. Dec. 5, 2019) (affording confidential treatment to the same categories of information filed in Kentucky Power's April 30, 2018 responses to the Commission's Order in Administrative Case No. 387). The Commission also granted confidential treatment to similar information as that presented in Kentucky Power's response to Data Request No. 6, pertaining to planned future outages, in its August 23, 2017 order in Case No. 2017-00001. *See* Order, *In the Matter of: Electronic Examination Of The Application Of The Fuel Adjustment Clause Of Kentucky Power Company From November 1, 2014 Through April 30, 2016*, Case No. 2018-00216 (Ky. P.S.C. August 23, 2017).

customers by providing data that could provide a competitive advantage to Kentucky Power's direct competitors thereby affecting Kentucky Power's ability to minimize costs for its rate paying customers.

5. Unit availability information is especially useful for competition as savvy marketers can estimate Kentucky Power's generation position and raise generation offers if the marketers believe Kentucky Power will be energy short, resulting in the Company paying higher prices to procure energy to serve its customers. This type of data is highly valued by competing energy marketers and traders who speculate in forward energy transactions. Using forecasted unit availability data, other parties could improve their forecast accuracy of future Kentucky Power operations and utilize the resulting intelligence to influence negatively the Company's costs of providing electricity to its customers. Such actions would ultimately raise the cost to Kentucky Power's customers.

6. Confidential Attachment 2 to the Company's response to Data Request No. 6 should be kept confidential for the period covered by the response (through the end of calendar year 2024). At such time there will no longer be any competitive advantage to be gained from the information.

2. Confidential Attachment 1 To The Response To Data Request No. 9.

7. Confidential Attachment 1 to Kentucky Power's response to Data Request No. 9 provides information regarding planned transmission projects that have yet to be publicly disclosed. The wholesale power market is extremely competitive. In addition to sales and purchases by utilities, competitive power providers, and electricity marketers, investment banks and other financial traders take financial positions, such as futures contracts and derivatives,

including options, price swaps, basis swaps, and forward contracts, with respect to the wholesale electricity market.

8. The wholesale price of electricity, as well as associated financial instruments, can be affected by the capacity and availability of transmission facilities. Information regarding planned changes or upgrades to transmission facilities can be used by market participants in making their pricing decisions.

9. Kentucky Power seeks confidential treatment of the identified information included in Attachment 1 to its response to Data Request No. 9 until the information is made public through the PJM Interconnection, L.L.C. transmission planning process.

B. The Identified Information is Generally Recognized As Confidential and Proprietary and Public Disclosure Of It Will Result In An Unfair Commercial Advantage.

10. The identified information required to be disclosed by Kentucky Power in response to the two data requests is confidential and not generally known or readily ascertainable by other parties through normal or proper means. No reasonable amount of legitimate independent research could yield this confidential information to other parties. Dissemination of the information for which confidential treatment is being requested is restricted by Kentucky Power, its affiliated operating companies, American Electric Power Company, Inc. ("AEP"), and American Electric Power Service Corporation ("AEPSC" together, the "AEP Entities"). The AEP Entities take all reasonable measures to prevent its disclosure to the public as well as persons within the AEP Entities who do not have a need for the information. The information is not disclosed to persons outside the AEP Entities. Within those organizations, the information is available only upon a confidential need-to-know basis that does not extend beyond those employees with a legitimate business need to know and act upon the identified information.

C. **The Identified Information Is Required To Be Disclosed To An Agency.**

11. The identified information is by the terms of the Commission's Order in Administrative Case No. 387 required to be disclosed to the Commission. The Commission is a "public agency" as that term is defined at KRS 61.870(1). Any filing should be subject to a confidentiality order and any party requesting such information should be required to enter into an appropriate confidentiality agreement.

WHEREFORE, Kentucky Power Company respectfully requests the Commission to enter an Order:

1. According confidential status to and withholding from public inspection the identified information; and

2. Granting Kentucky Power all further relief to which it may be entitled.

Respectfully submitted,

Mark R. Overstreet
STITES & HARBISON PLLC
421 West Main Street
P. O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477

COUNSEL FOR KENTUCKY POWER COMPANY

Kentucky Power Company
KPSC Case No. Administrative Case No. 387 - 2020
Annual Responses
Dated March 19, 2020

DATA REQUEST

1 Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm). Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Please refer to Page 1 of KPCO_R_KPSC_1_1_Attachment1 for actual and weather normalized 2019 monthly peak native load demands for Kentucky Power Company. Kentucky Power Company had four customers with interruptible provisions in their contracts in 2019 for PJM initiated events.

Combined, these customers had approximately 3.6 MW of interruptible load available for use in PJM capacity auctions. The interruptible load available for PJM auctions reflects the average load for these customers, less contractually firm load, at the time of the PJM five coincident peaks in the summer of 2018.

Please refer to Page 2 of KPCO_R_KPSC_1_1_Attachment1 for actual 2019 monthly system demands for Kentucky. The system demands include internal load and off-system sales. Weather-normalized monthly peak system demands for Kentucky Power Company have not been developed and are not available.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the requested information regarding the AEP-East Power Pool is no longer available.

Witness: Brian K. West

Kentucky Power Company
Actual and Weather Normalized Peak Internal Demand (MW)
2019

	Kentucky Power Company			
Month	**Peak**	**Peak Day**	**Peak Hour**	**Normalized Peak**
January	1,297	1/31/2019	8	1,315
February	1,010	2/1/2019	10	1,175
March	1,124	3/6/2019	8	1,090
April	944	4/1/2019	7	774
May	908	5/28/2019	16	834
June	961	6/27/2019	16	973
July	985	7/19/2019	16	1,021
August	993	8/19/2019	16	1,000
September	976	9/11/2019	16	924
October	946	10/1/2019	16	714
November	1,110	11/13/2019	8	1,007
December	1,087	12/19/2019	8	1,152

Kentucky Power Company
Actual Peak System Demand (MW)
2019

	Kentucky Power Company		
Month	**Peak**	**Peak Day**	**Peak Hour**
January	1,451	1/31/2019	8
February	1,184	2/19/2019	19
March	1,235	3/7/2019	8
April	1,035	4/5/2019	10
May	984	5/20/2019	18
June	1,309	6/28/2019	14
July	1,421	7/28/2019	18
August	1,320	8/17/2019	17
September	1,194	9/15/2019	20
October	1,152	10/1/2019	16
November	857	11/19/2019	11
December	719	12/20/2019	9

Kentucky Power Company
KPSC Case No. Administrative Case No. 387 - 2020
Annual Responses
Dated March 19, 2020

DATA REQUEST

2 Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

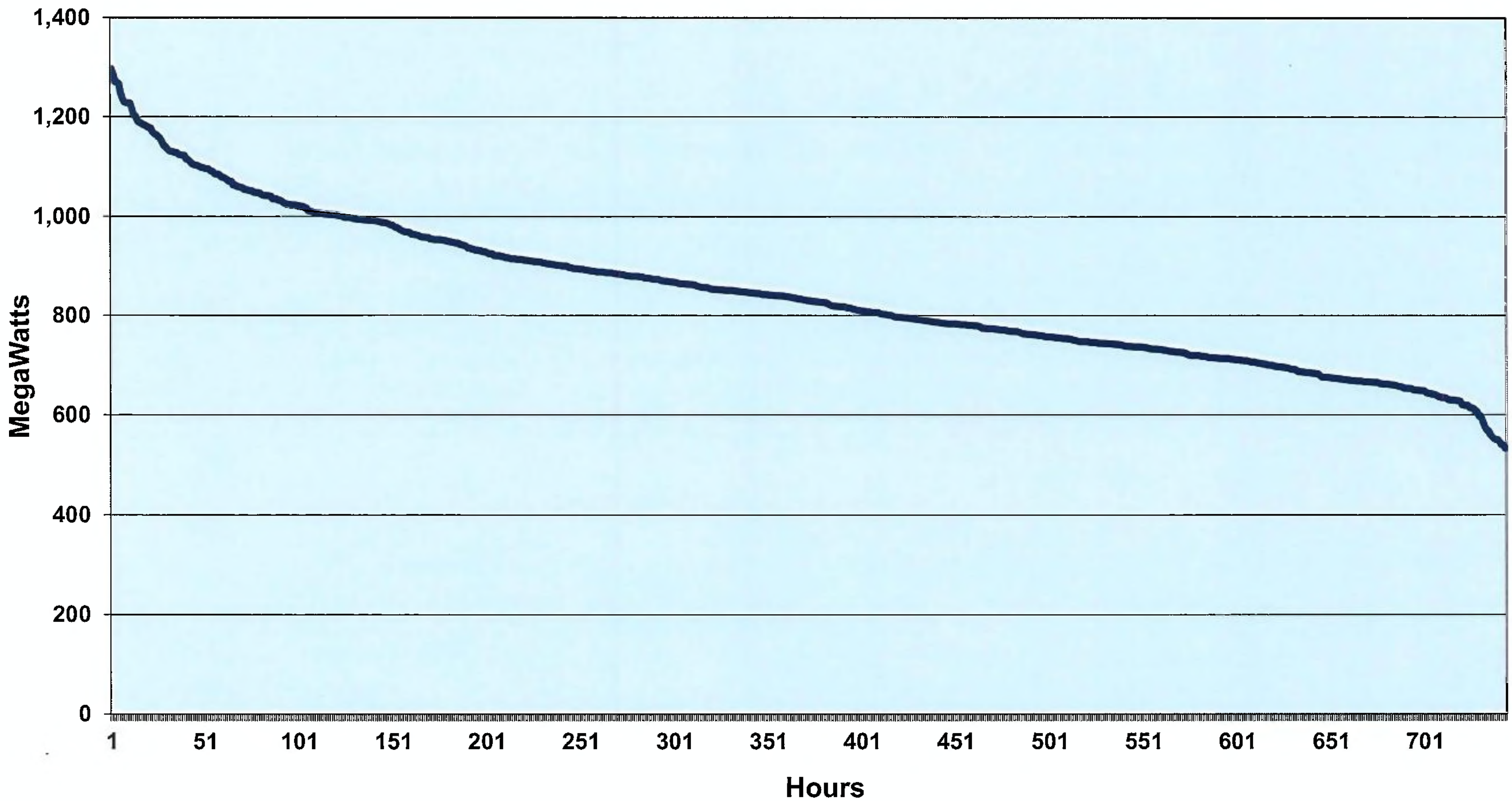
Please refer to Pages 1 through 12 of KPCO_R_KPSC_1_2_Attachment1 for 2019 monthly load duration curves for Kentucky Power Company's internal native load. Please refer to Pages 13 through 24 of KPCO_R_KPSC_1_2_Atttachment1 for 2019 monthly load duration curves for Kentucky Power Company's system load. The system load, for Kentucky Power Company, includes internal load and off-system sales.

Weather-normalized monthly internal peaks for Kentucky Power Company are provided on Page 1 of KPCO_R_KPSC_1_1_Attachment1. Weather normalized system peaks have not been developed and are not available.

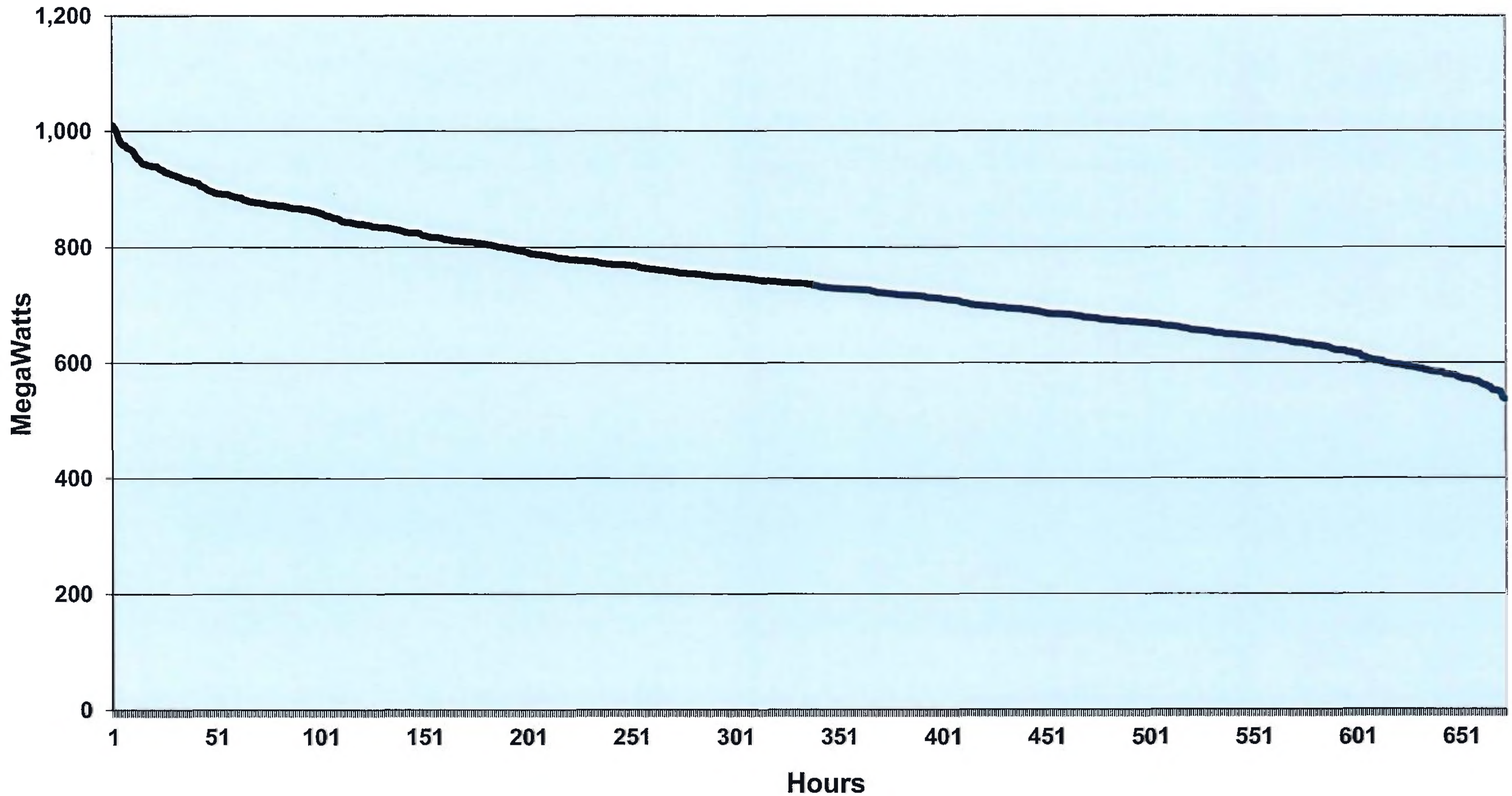
The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the requested information regarding the AEP-East Power Pool is no longer available.

Witness: Brian K. West

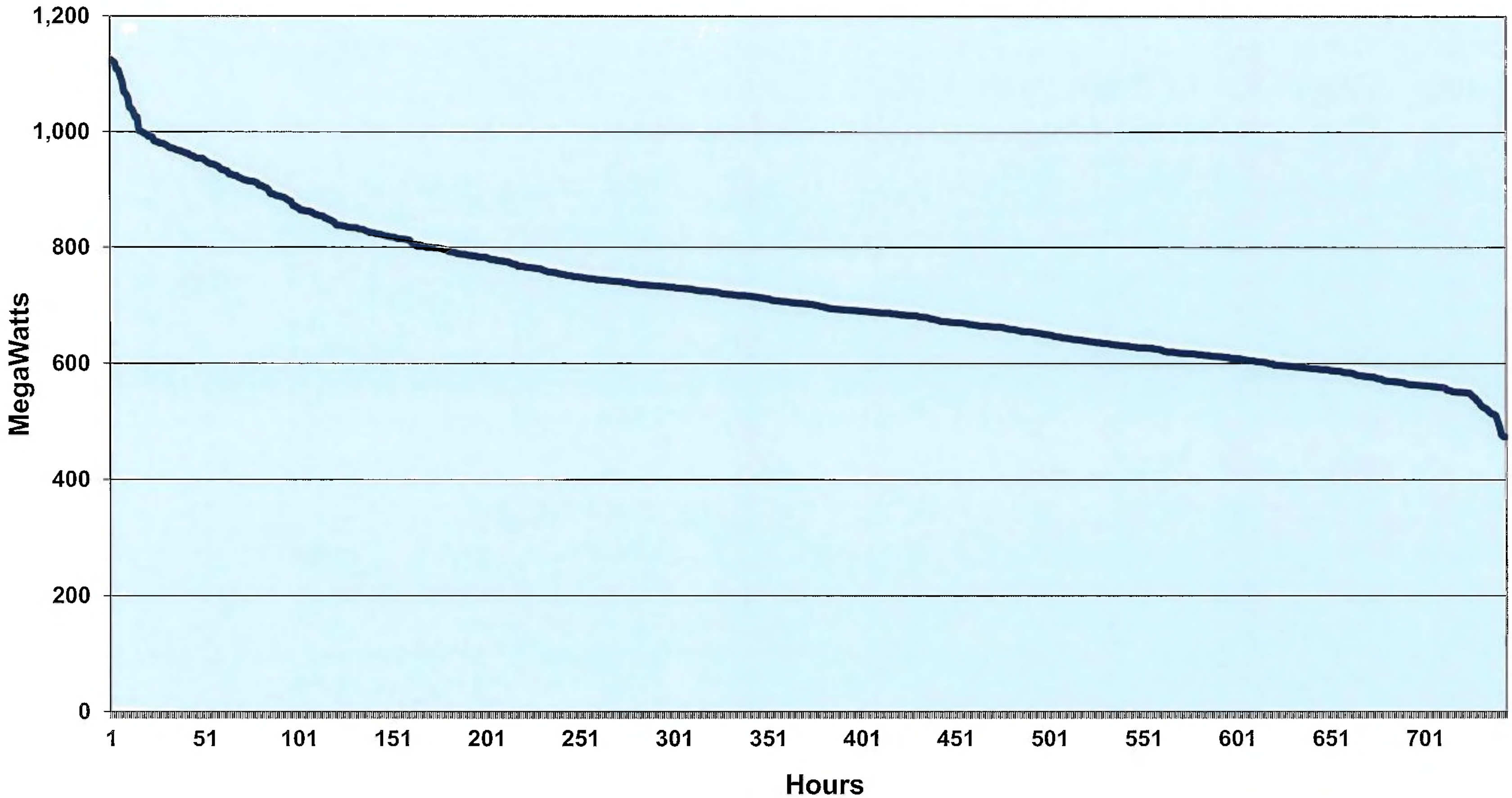
Kentucky Power Company
January 2019 Load Duration Curve
(Internal Load)



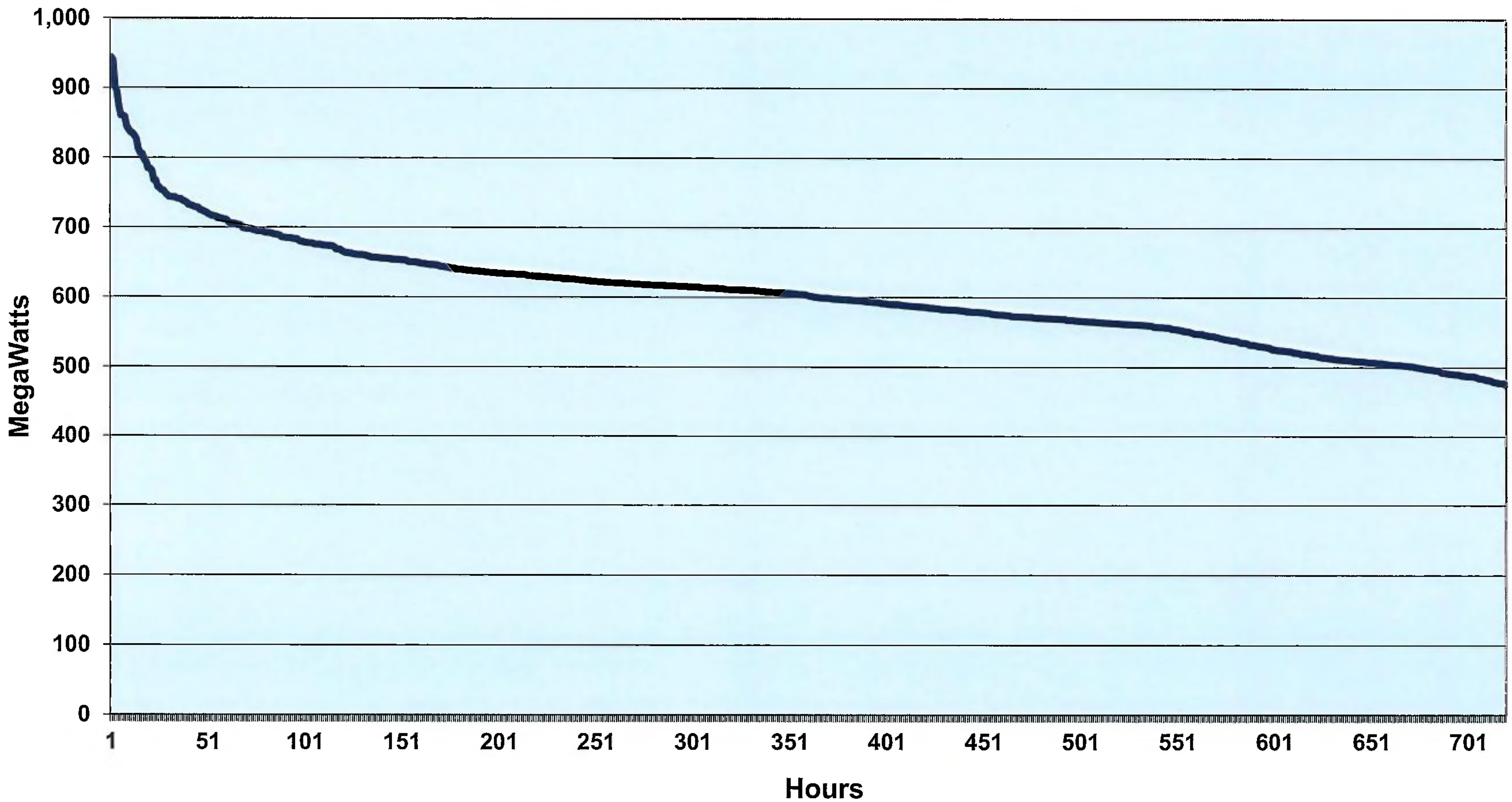
Kentucky Power Company
February 2019 Load Duration Curve
(Internal Load)



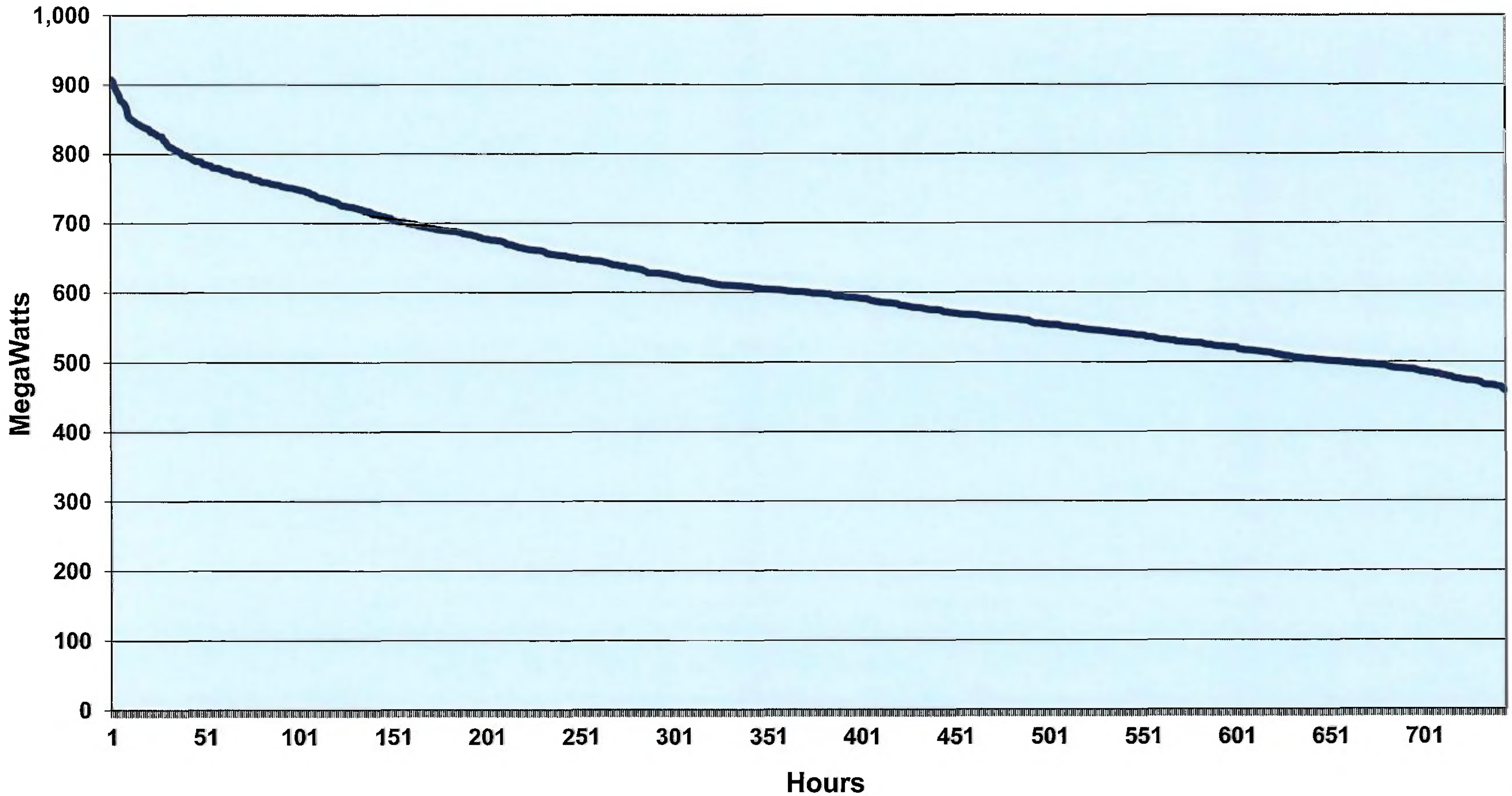
Kentucky Power Company
March 2019 Load Duration Curve
(Internal Load)



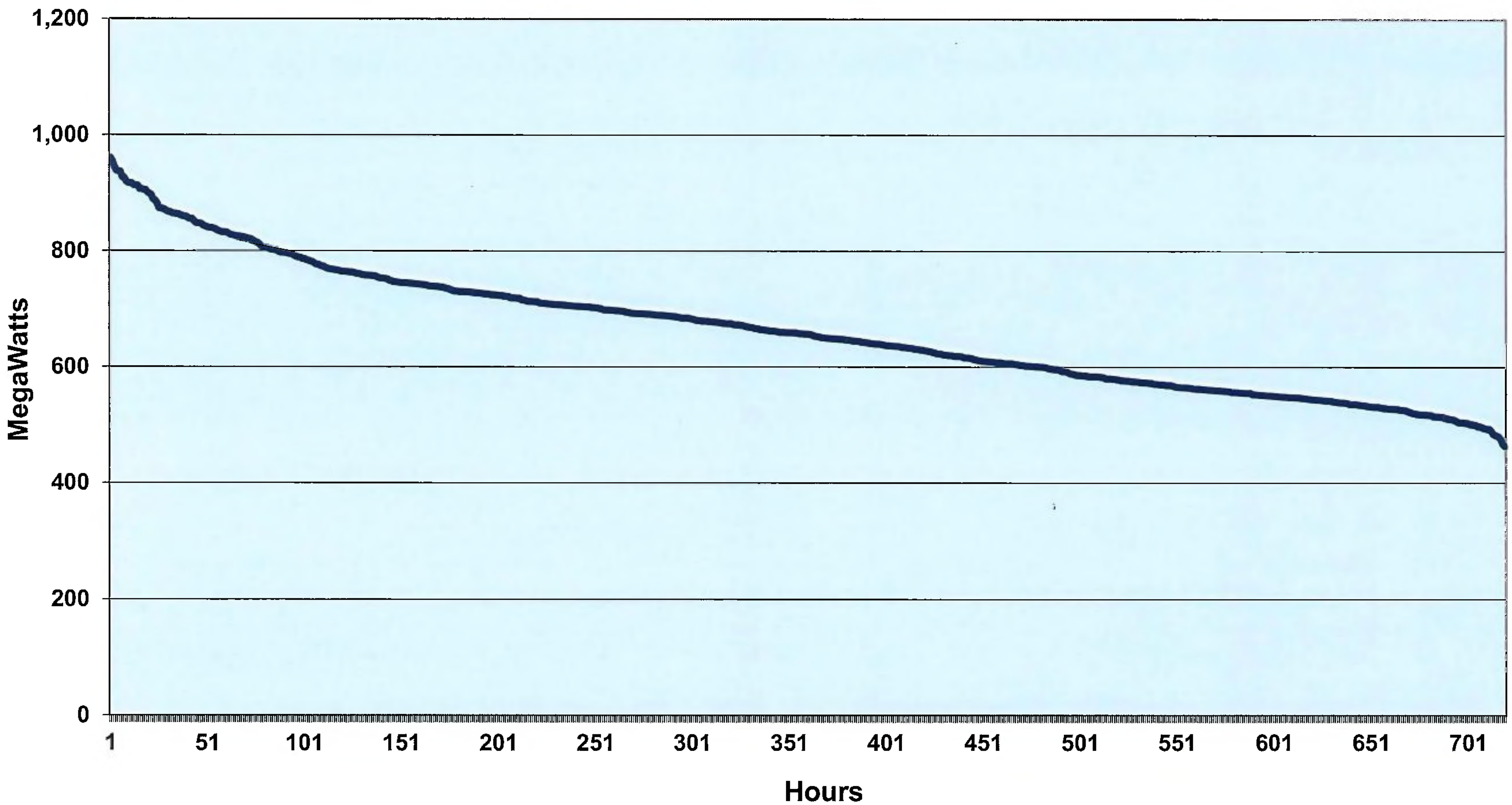
Kentucky Power Company
April 2019 Load Duration Curve
(Internal Load)



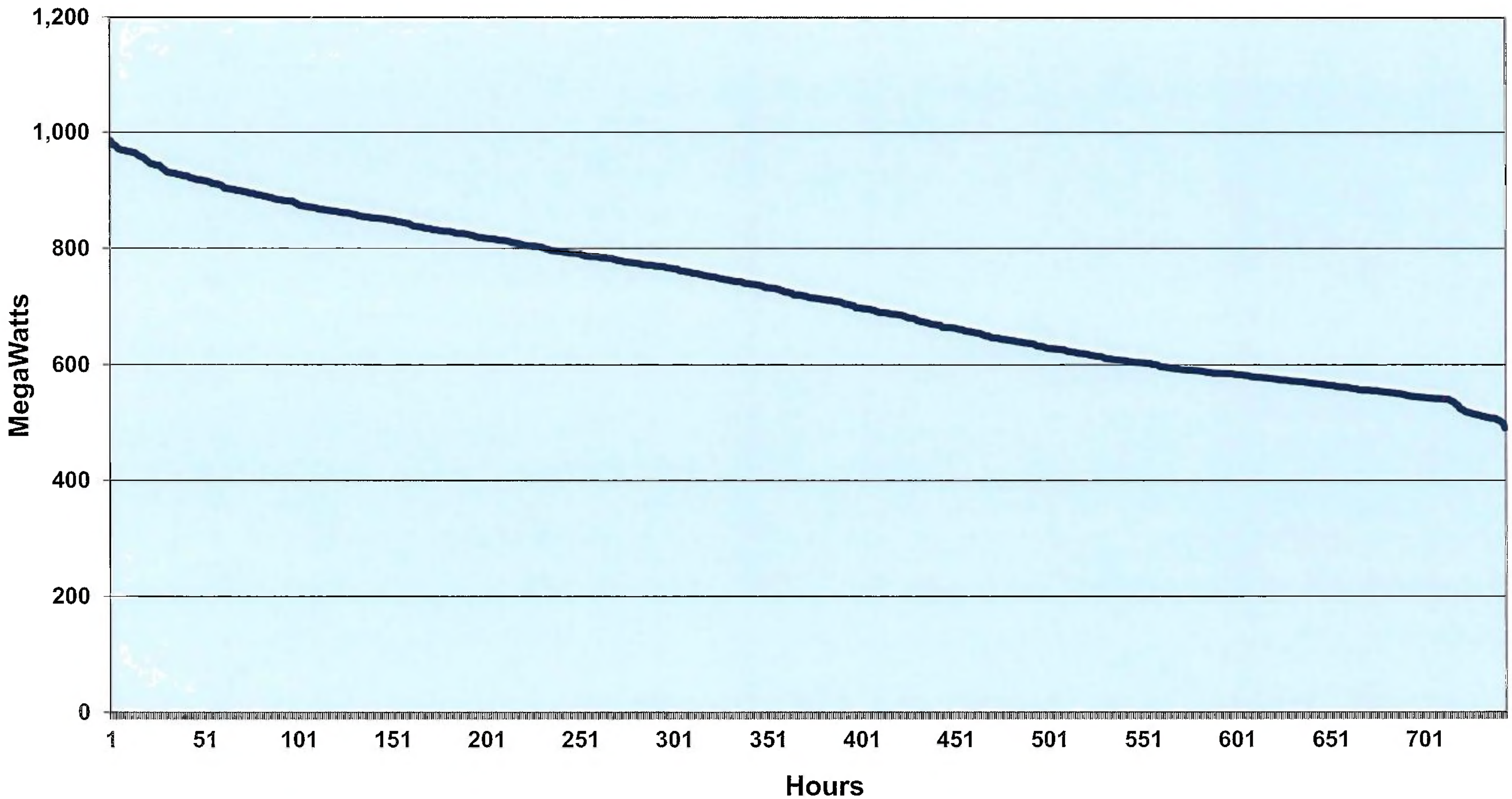
Kentucky Power Company
May 2019 Load Duration Curve
(Internal Load)



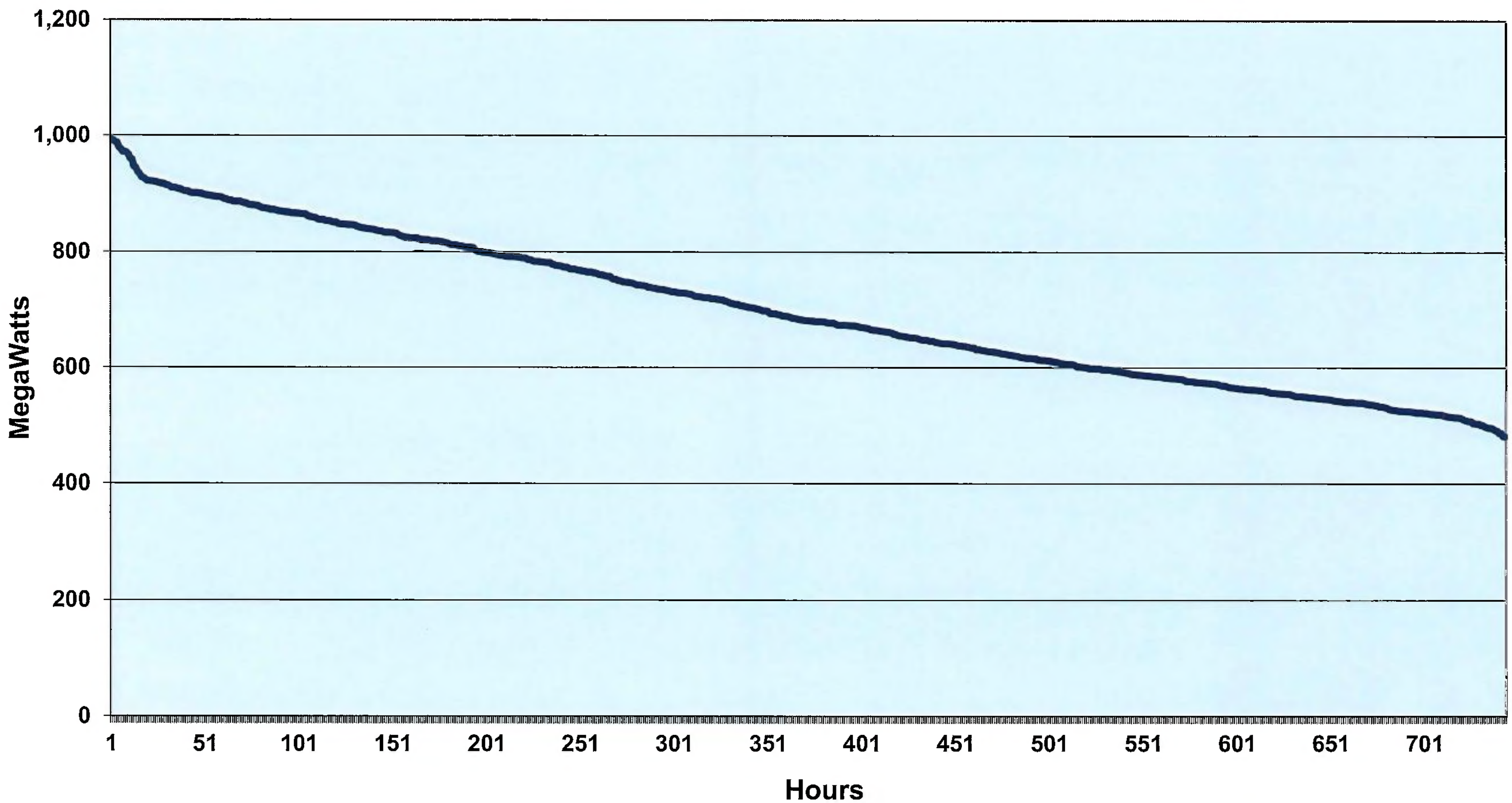
Kentucky Power Company
June 2019 Load Duration Curve
(Internal Load)



Kentucky Power Company
July 2019 Load Duration Curve
(Internal Load)

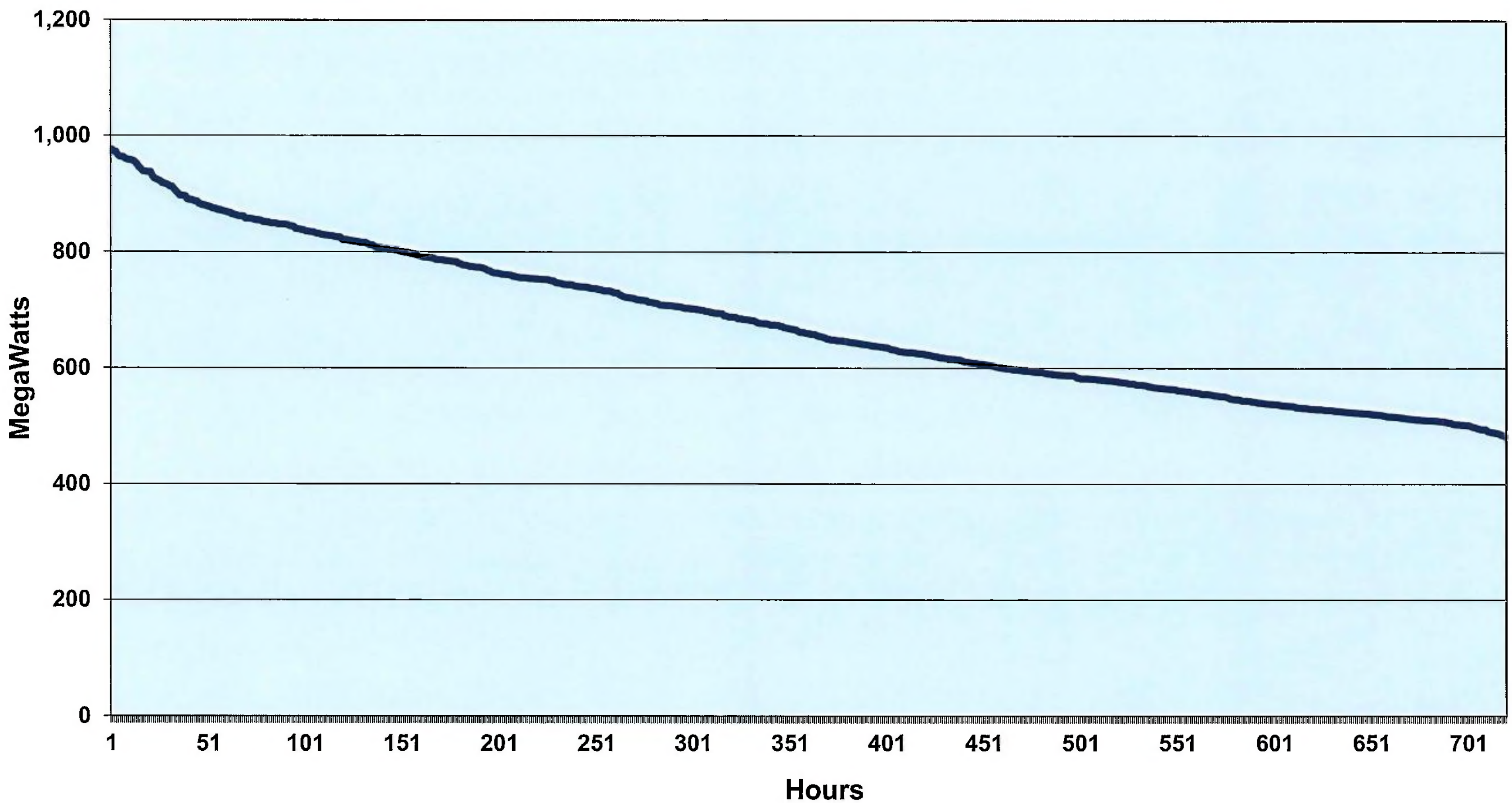


Kentucky Power Company
August 2019 Load Duration Curve
(Internal Load)



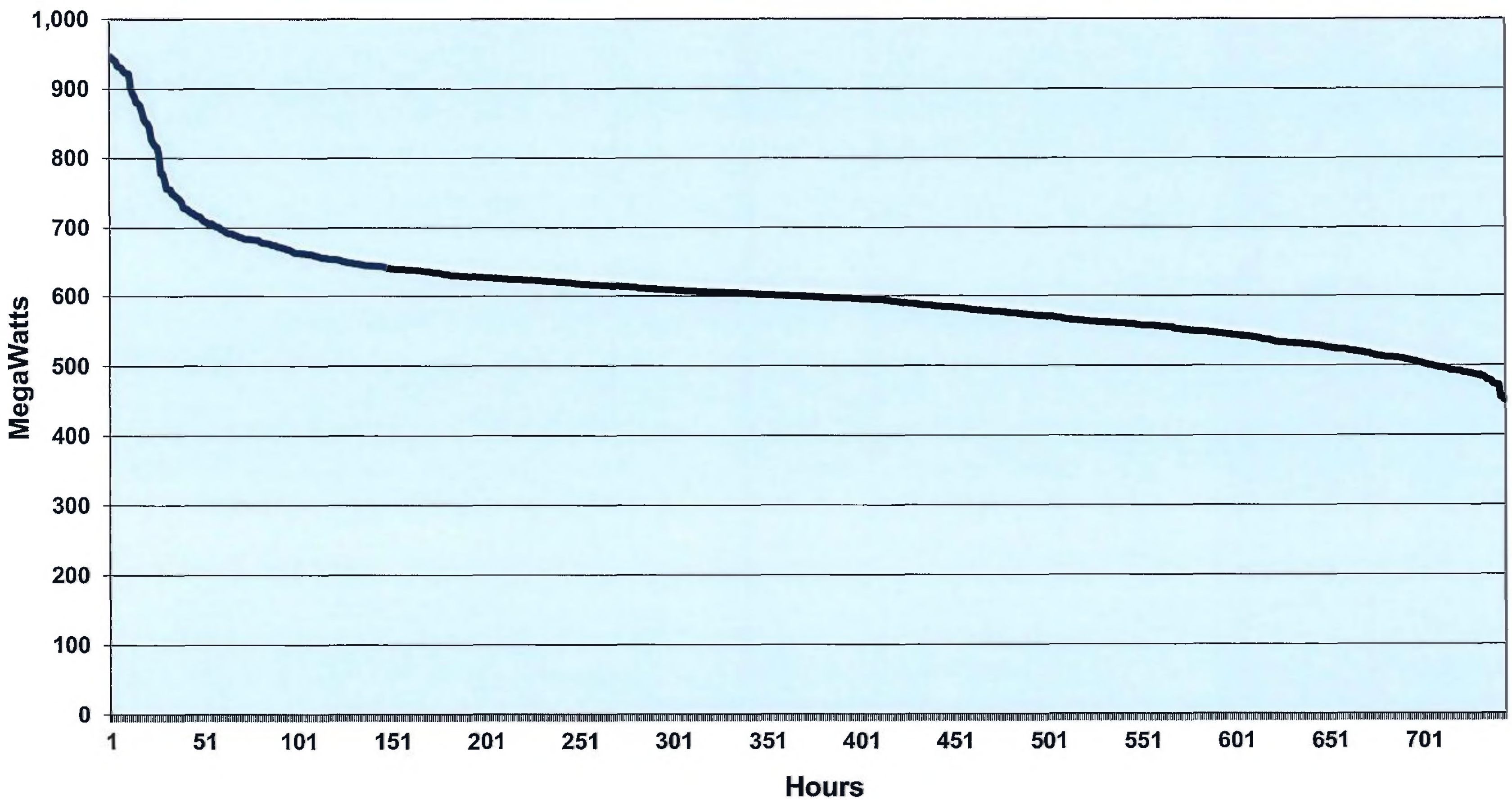
KPSC Administrative Case No. 387
Order Dated December 20, 2001
Calendar Year 2019
Annual Resource Assessment
Item No. 2
Attachment 1
Page 8 of 24

Kentucky Power Company
September 2019 Load Duration Curve
(Internal Load)

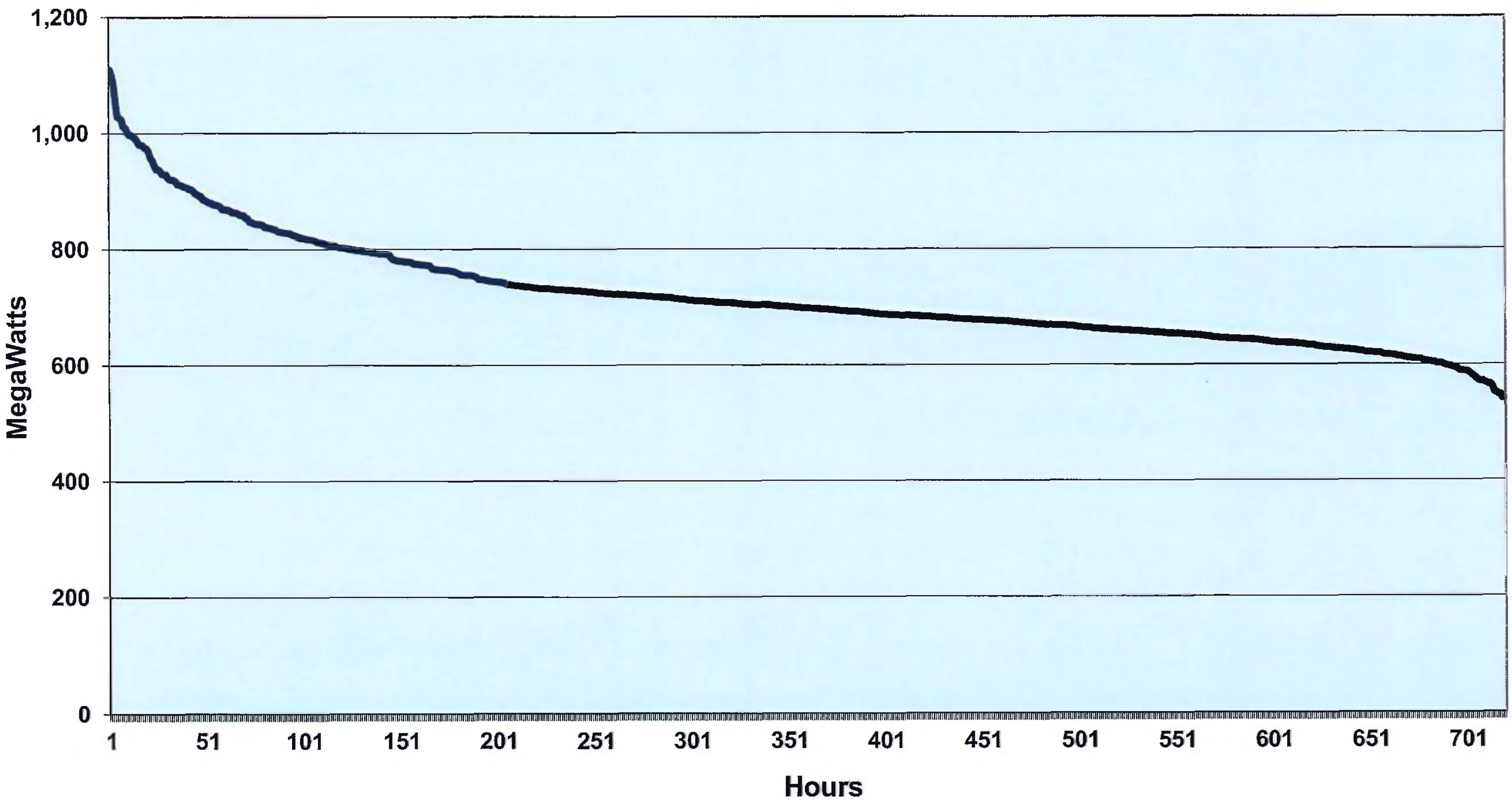


KPSC Administrative Case No. 387
Order Dated December 20, 2001
Calendar Year 2019
Annual Resource Asssessment
Item No. 2
Attachment 1
Page 9 of 24

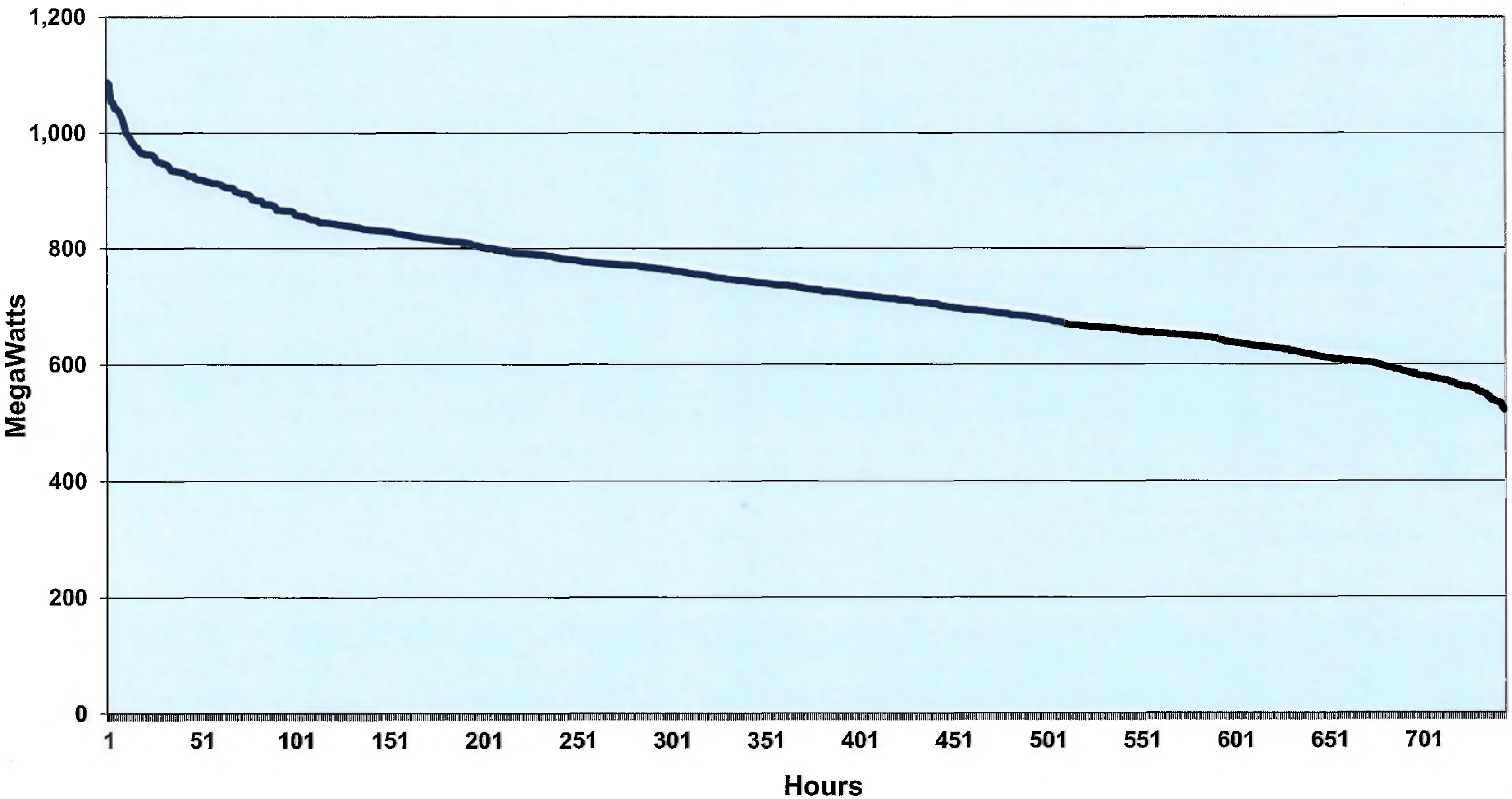
Kentucky Power Company
October 2019 Load Duration Curve
(Internal Load)



Kentucky Power Company
November 2019 Load Duration Curve
(Internal Load)

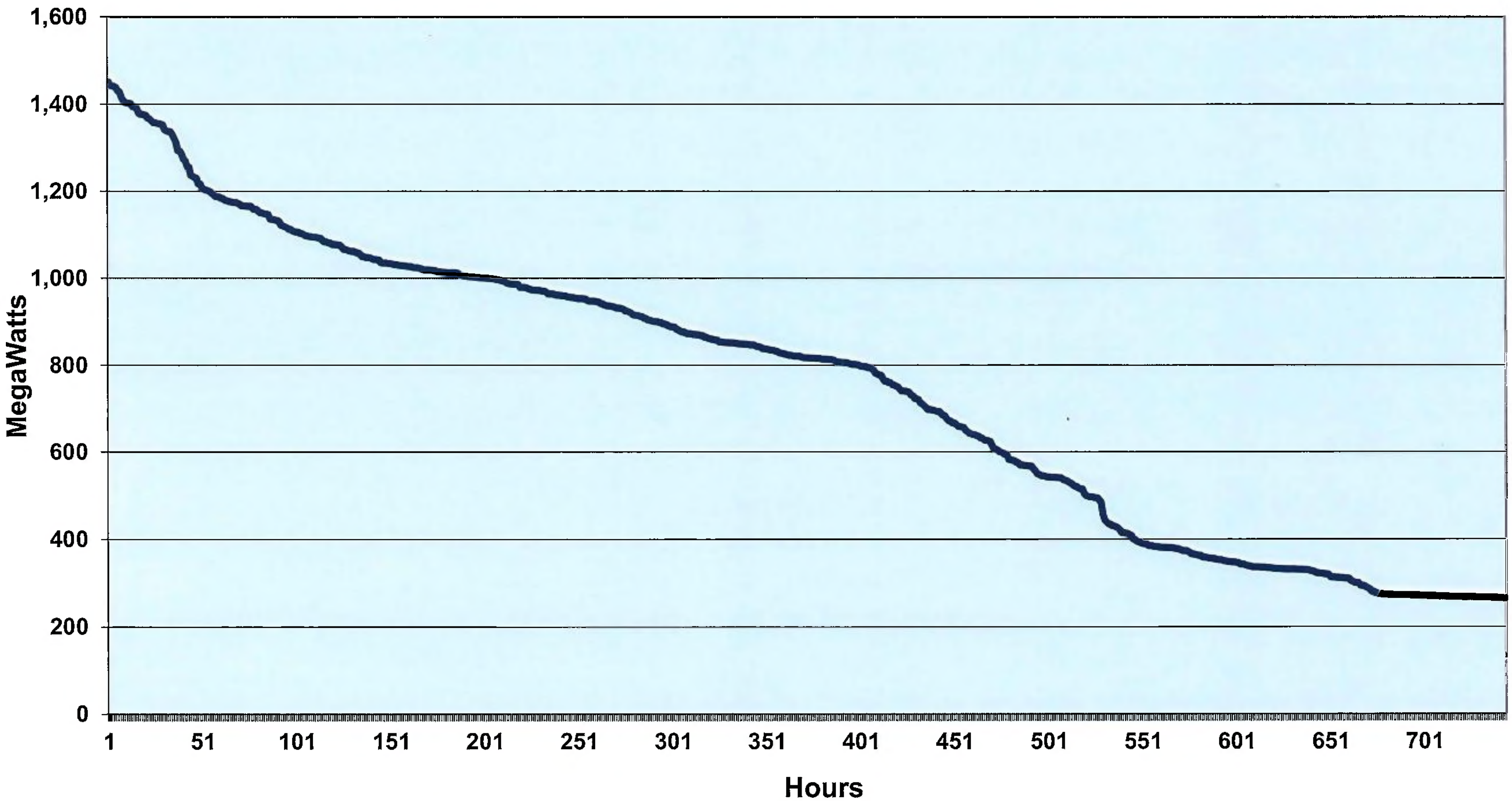


Kentucky Power Company
December 2019 Load Duration Curve
(Internal Load)

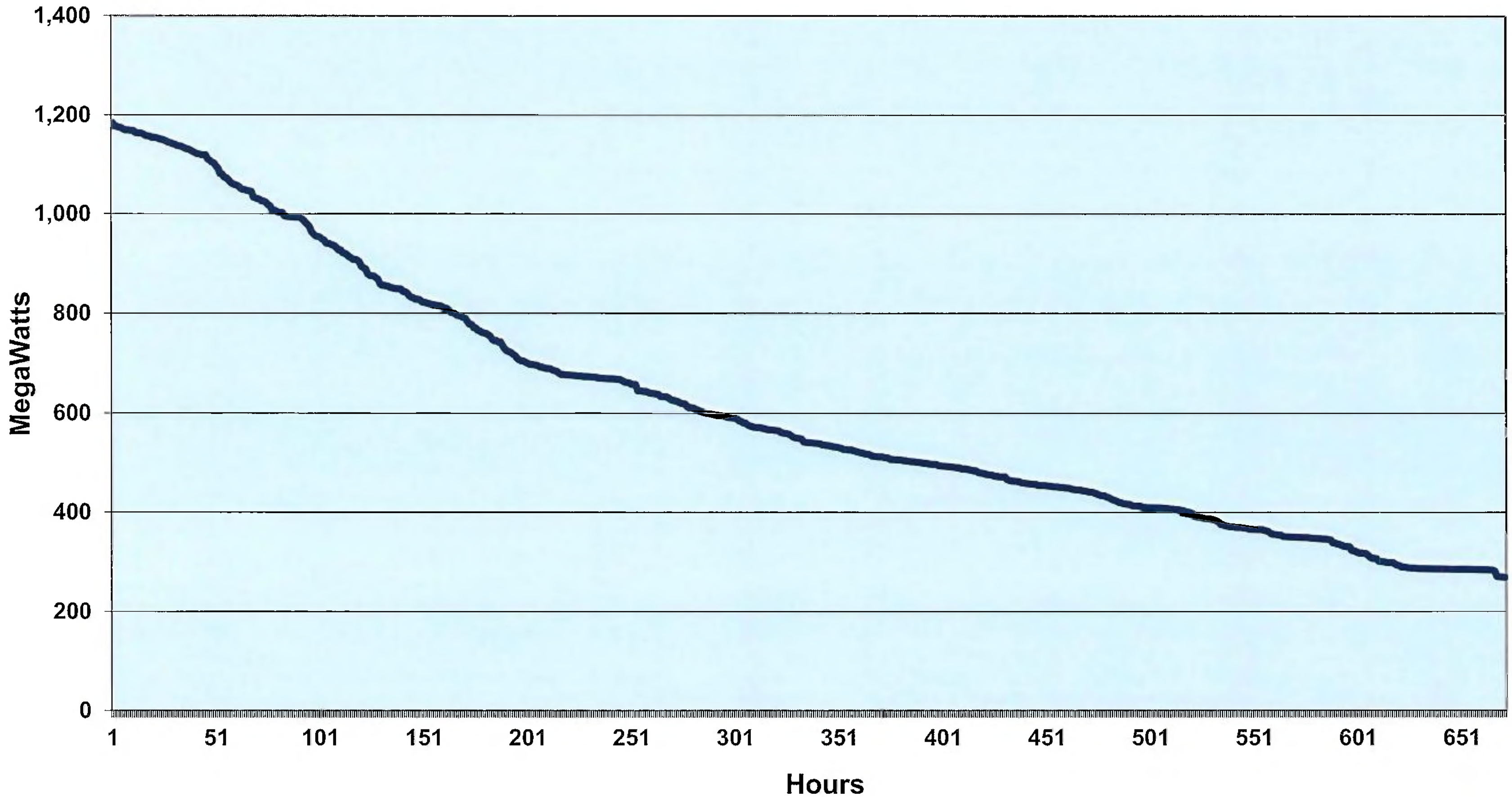


KPSC Administrative Case No. 387
Order Dated December 20, 2001
Calendar Year 2019
Annual Resource Assessment
Item No. 2
Attachment 1
Page 12 of 24

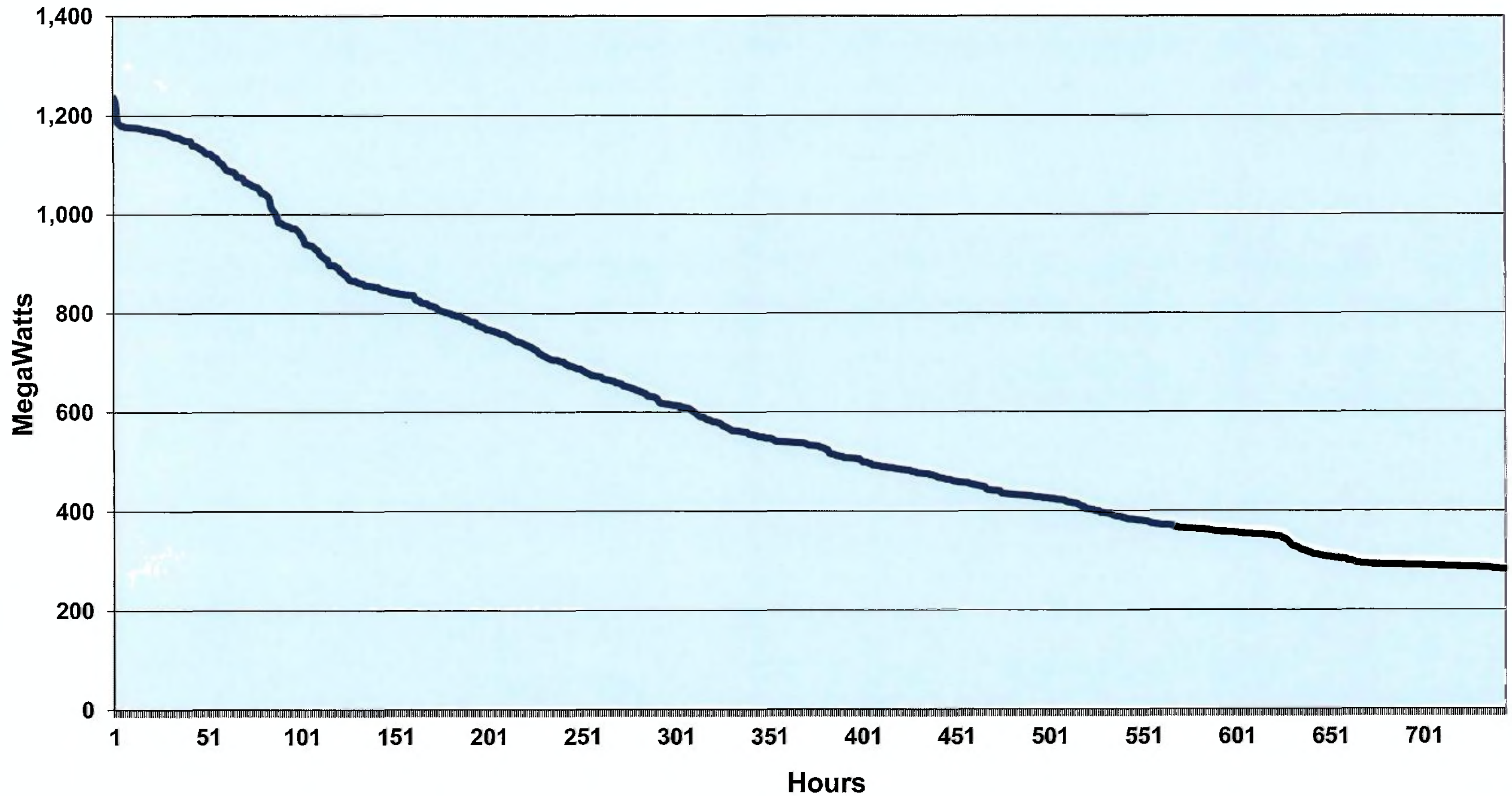
Kentucky Power Company
January 2019 Load Duration Curve
(System Load)



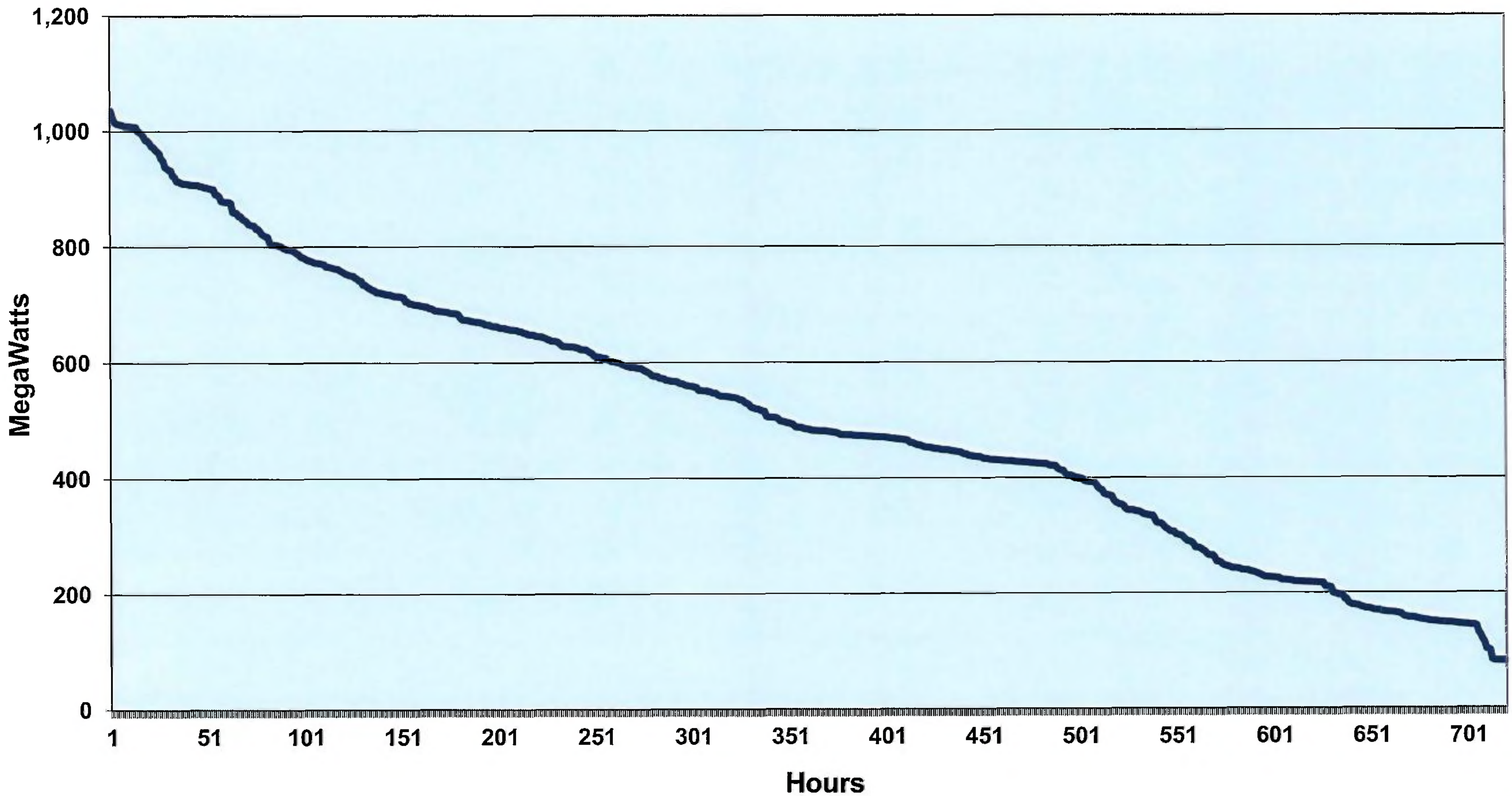
Kentucky Power Company
February 2019 Load Duration Curve
(System Load)



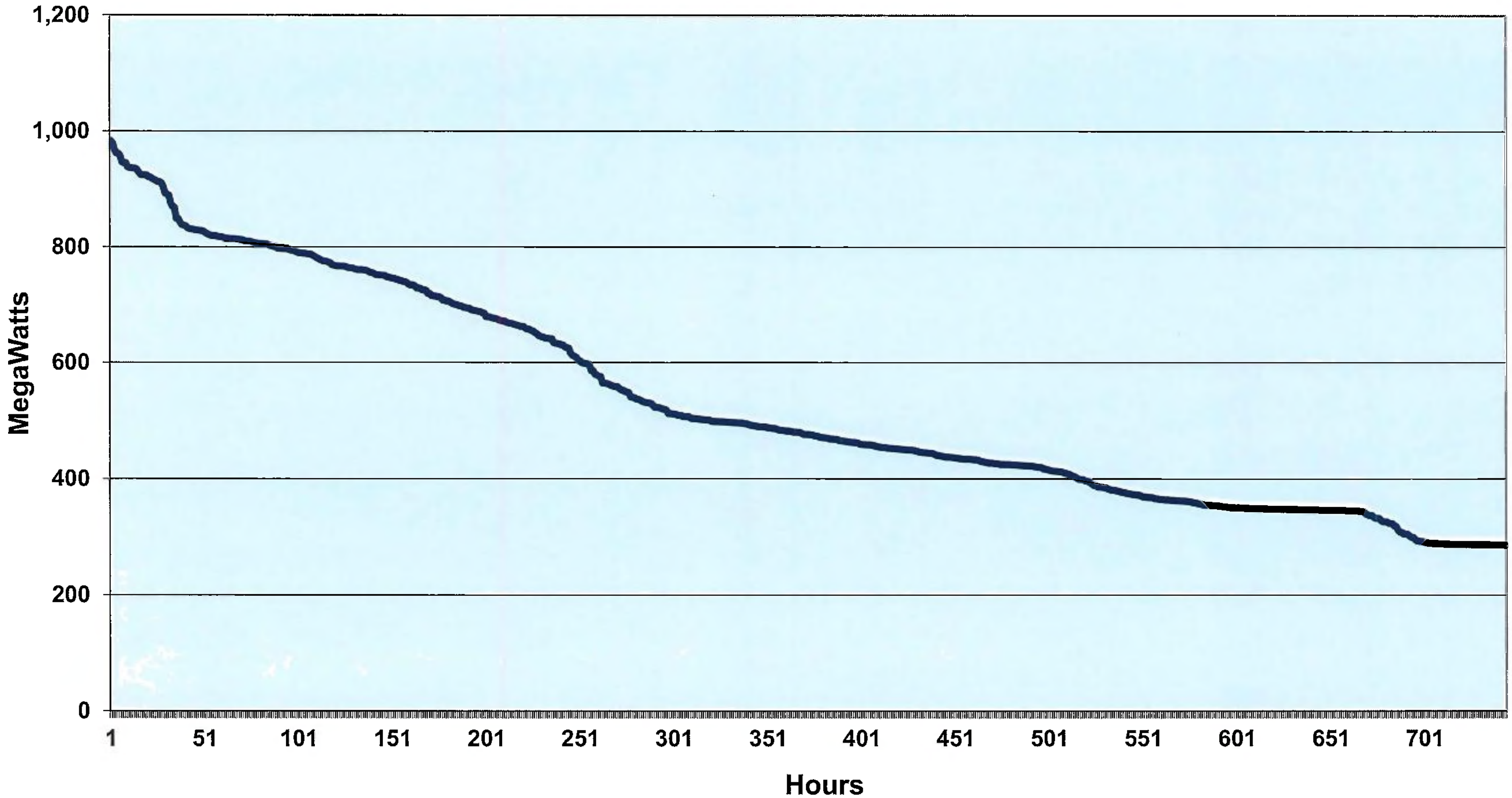
Kentucky Power Company
March 2019 Load Duration Curve
(System Load)



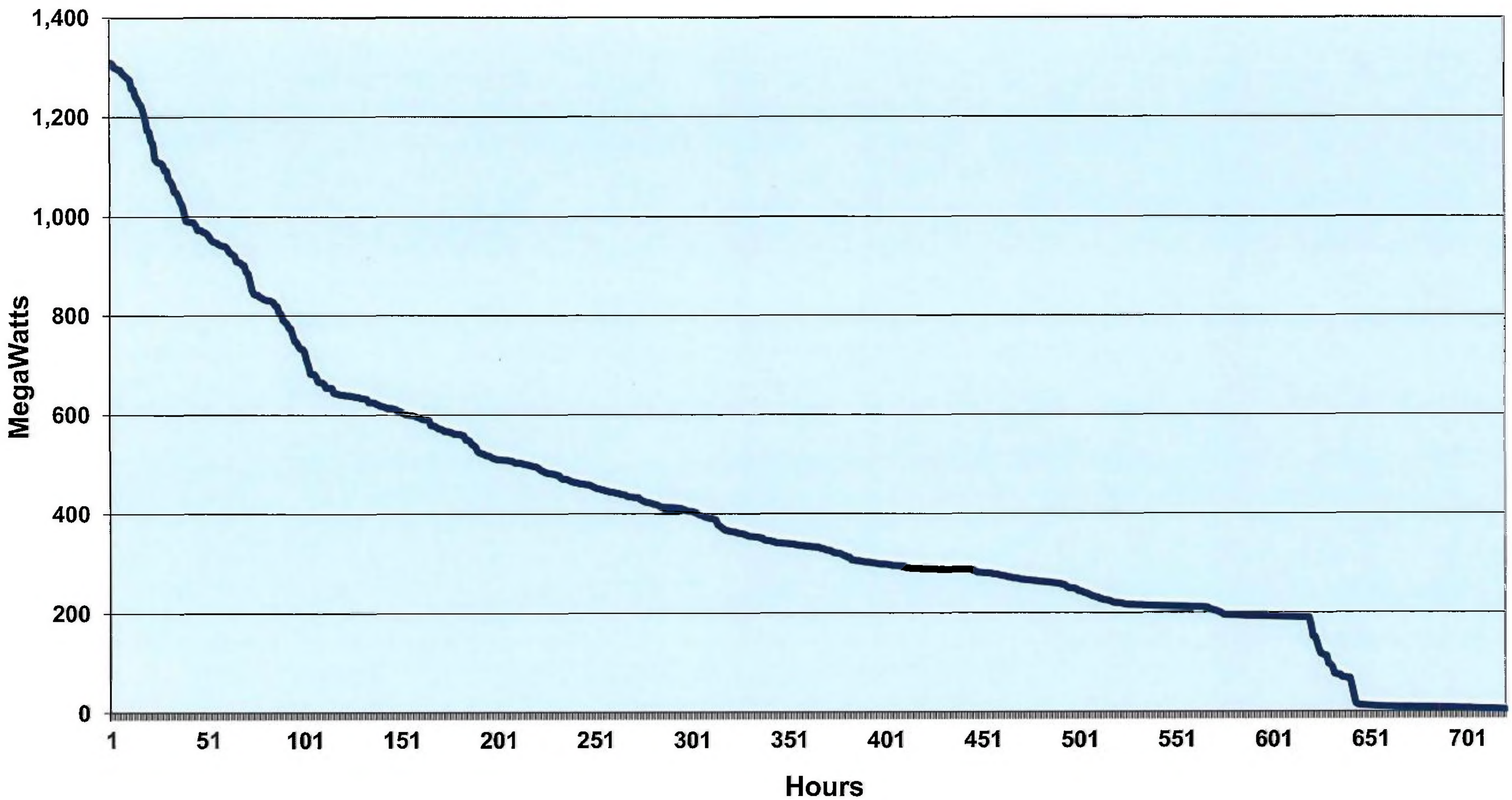
Kentucky Power Company
April 2019 Load Duration Curve
(System Load)



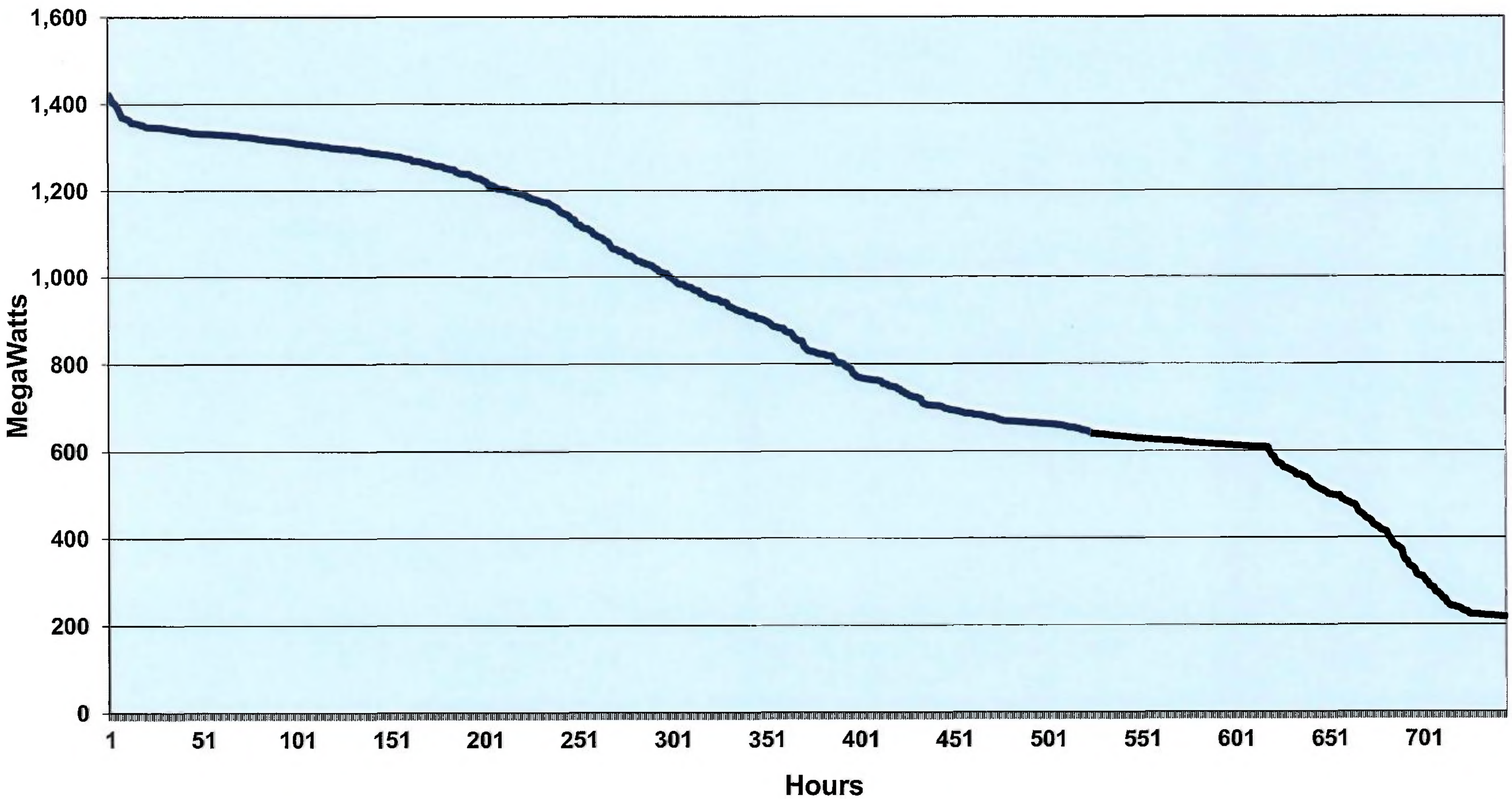
Kentucky Power Company
May 2019 Load Duration Curve
(System Load)



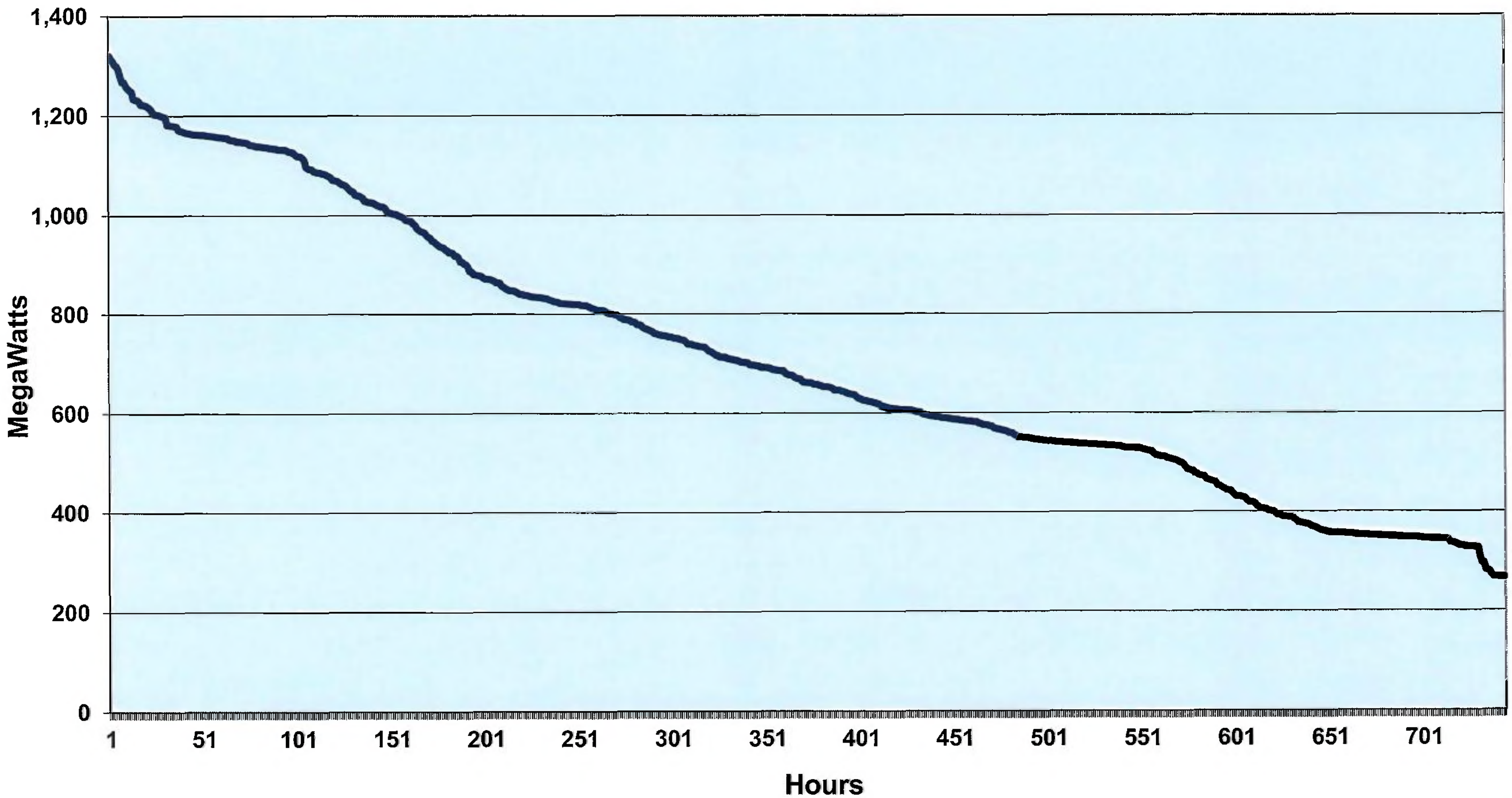
Kentucky Power Company
June 2019 Load Duration Curve
(System Load)



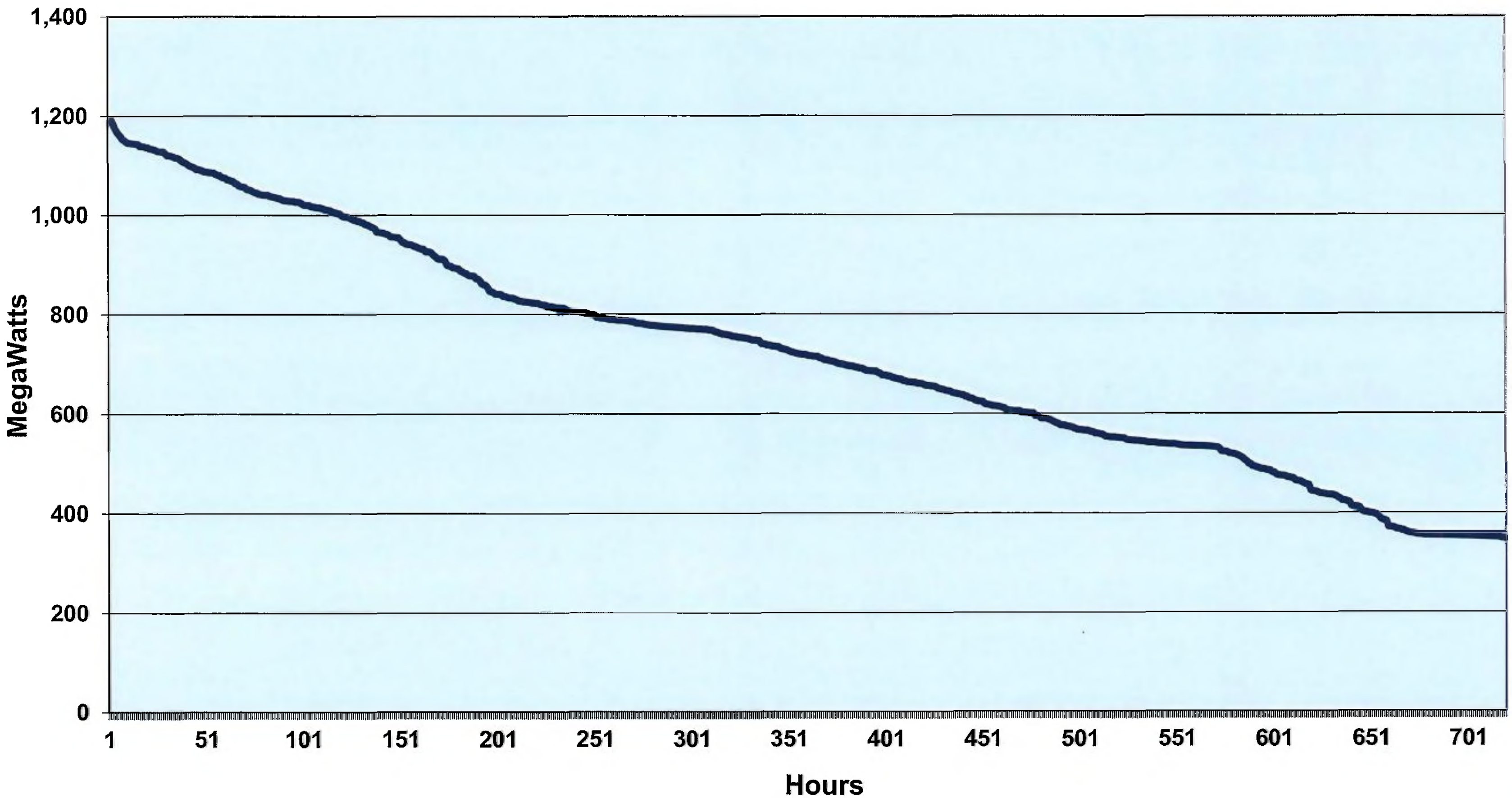
Kentucky Power Company
July 2019 Load Duration Curve
(System Load)



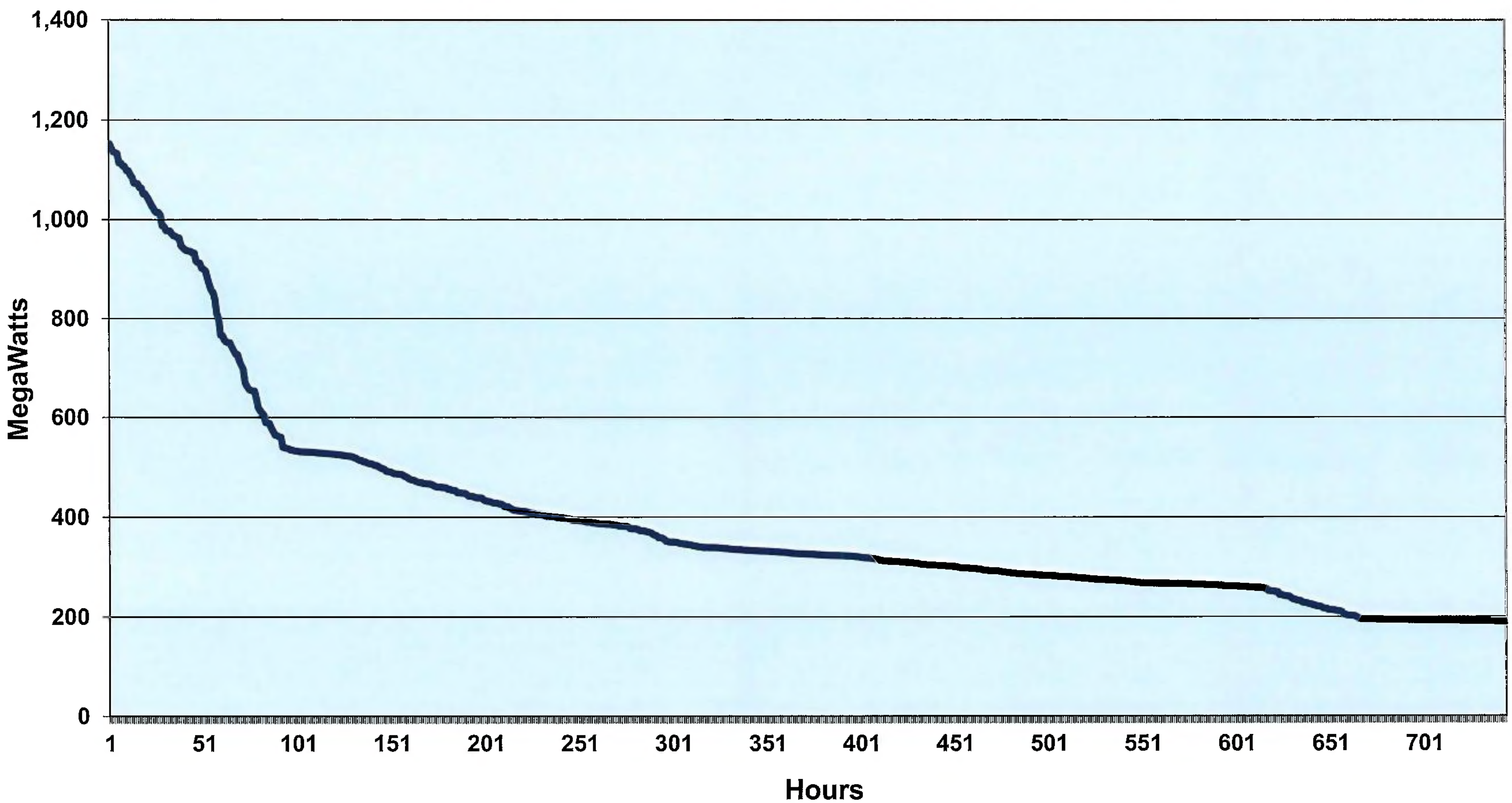
Kentucky Power Company
August 2019 Load Duration Curve
(System Load)



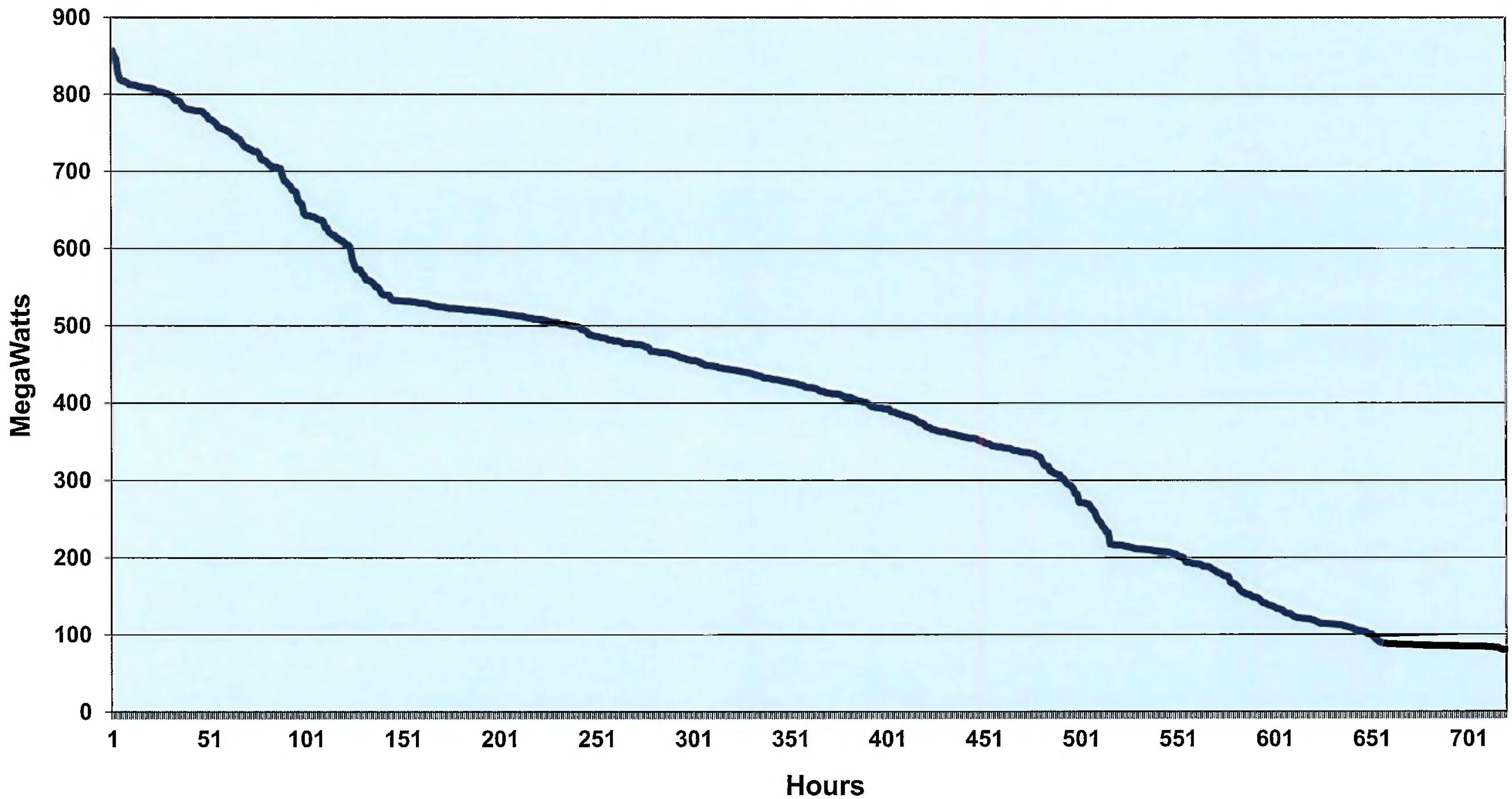
Kentucky Power Company
September 2019 Load Duration Curve
(System Load)



Kentucky Power Company
October 2019 Load Duration Curve
(System Load)



Kentucky Power Company
November 2019 Load Duration Curve
(System Load)



KPSC Administrative Case No. 387
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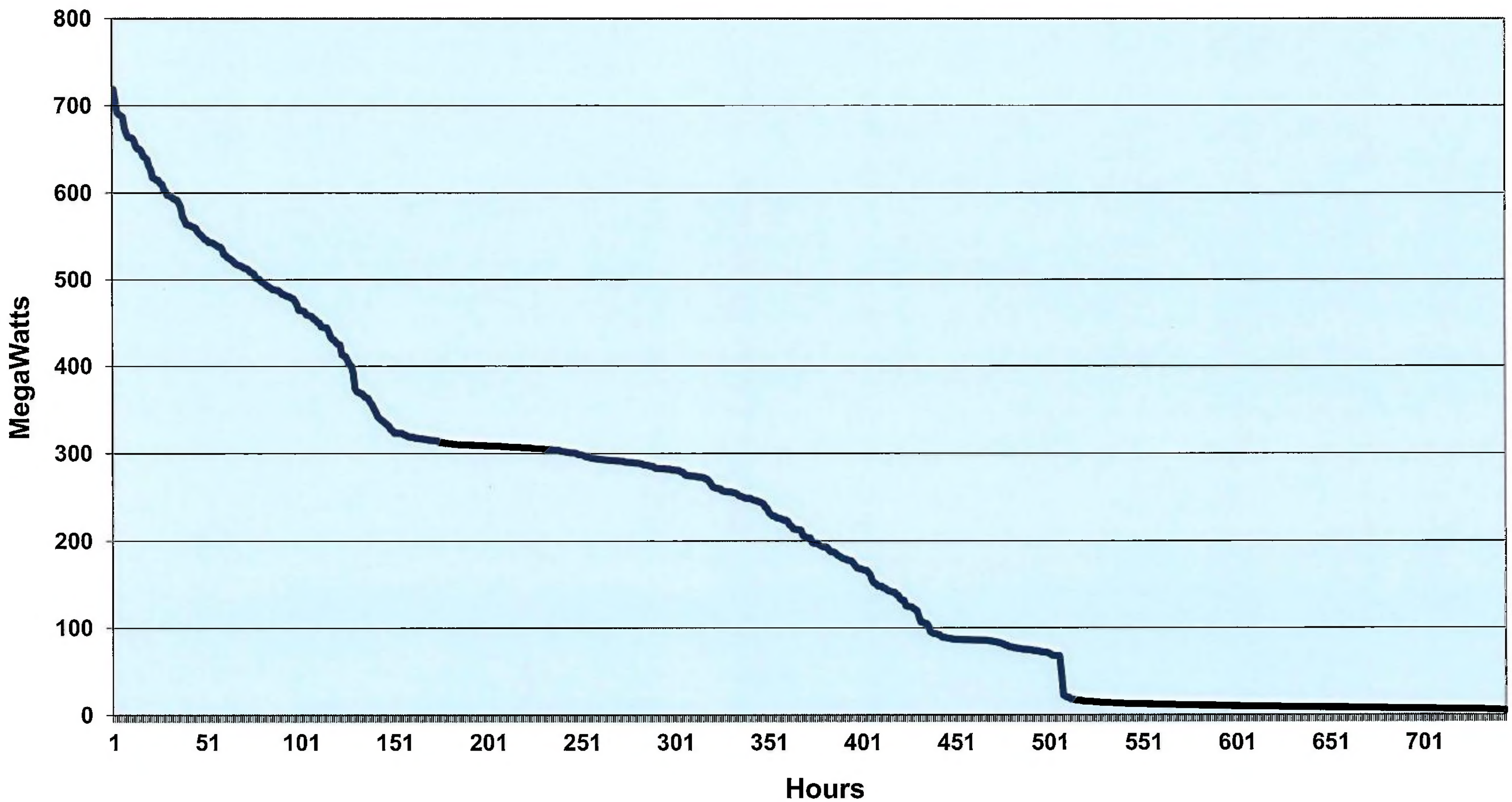
Kentucky Power Company
December 2019 Load Duration Curve
(System Load)



Kentucky Power Company
KPSC Case No. Administrative Case No. 387 - 2020
Annual Responses
Dated March 19, 2020

DATA REQUEST

3 Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand). Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Please refer to Page 1 of KPCO_R_KPSC_1_3_Attachment1 for Kentucky Power Company's forecasts of seasonal peak internal demands and annual internal energy requirements. In addition, the associated high forecast for seasonal peak internal demands and internal energy requirements are provided on Page 1.

The off-system energy sales forecasts for Kentucky Power Company are provided on Page 2 of KPCO_R_KPSC_1_3_Attachment1. Forecasts of off-system peak demand for Kentucky Power Company have not been developed and are not available. In addition, high case forecasts for off-system energy sales and peak demand have not been developed and are not available.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the requested information regarding the AEP-East Power Pool is no longer available.

Witness: Brian K. West

Kentucky Power Company
Base and High Forecast
Energy Sales (GWH) and Seasonal Peak Demand (MW)
2020 - 2024

Year	Energy Sales		Summer Peak Demand		Preceding Winter Peak Demand	
	Base	High	Base	High	Base	High
2020	5,992	6,072	1,004	1,017	1,295	1,312
2021	5,969	6,086	1,002	1,021	1,293	1,319
2022	5,949	6,092	998	1,022	1,288	1,319
2023	5,928	6,093	995	1,023	1,280	1,315
2024	5,909	6,085	992	1,022	1,273	1,311

Kentucky Power Company
Forecast Off-System Energy Sales (GWh)
2020 - 2024

Year	KPCo Off-System Sales
2020	1,431
2021	1,156
2022	1,006
2023	550
2024	317

DATA REQUEST

4 The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

The AEP-East operating companies are required to comply with the PJM mandated reserve margin following PJM's October 1, 2004 integration of AEP's Eastern System into the PJM Interconnection.

The installed reserve margin requirement (IRM) is recalculated each year based on a five-year average of PJM generating units reliability, PJM load shape, and assistance available from neighboring regions. In addition, Kentucky Power's responsibility to PJM depends on its twelve-month history of generator reliability or Unforced Capacity value and its peak demand diversity in relation to the PJM total load.

For the delivery periods 2020/21 through 2024/25, PJM set the IRM at 15.5%, 15.1%, 14.9%, 14.8%, and 14.8%, respectively. Kentucky Power assumed the same IRM levels for PJM and other planning purposes.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the requested information regarding the AEP-East Power Pool is no longer available.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. Administrative Case No. 387 - 2020
Annual Responses
Dated March 19, 2020

DATA REQUEST

5 Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420)

RESPONSE

KPCO_R_KPSC_1_5_Attachment1 provides projected PJM peak demands, capabilities, and margins for Kentucky Power for PJM Planning Years 2020/21 through 2024/25. The Company has fully addressed its future resource needs in its Integrated Resource Plan filed December 20, 2019 in Case No. 2019-00443.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the requested information regarding the AEP-East Power Pool is no longer available.

Witness: Brian K. West

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)

		Obligation to PJM							Resources								KPCo Position (MW)		PJM Reserve Margin			
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)				
				=(1)+(2)				=((3)-((4)*(5)))*(6)			=(8)-(9)						=(13)+(14) - (7)	=(13)+(14) +(15)-(7)				
Planning Year		Internal Demand (a)	DSM(b)	Net Internal Demand	Interruptible Demand Response(c)	Demand Response Factor	Forecast Pool Req't(d)	Total UCAP Obligation	ICAP Existing Capacity & Planned Changes(e)	ICAP Net Capacity Sales	Net ICAP	Incremental Planned Capacity Additions (ICAP) Units	MW	Annual UCAP Purchases	UCAP Existing Capacity(f)	UCAP Planned Additions Capacity	Net Position w/o New Capacity	Net Position w/New Capacity	Total UCAP Obligation Less IDR and IRM	Installed Reserve Margin (IRM)	KPCo Reserve Margin Above PJM IRM	Total KPCo Reserve Margin
2020 /21	(g)	968	0	968	0	1	1.0882	1,053	1,467	77	1,390			0	1,283	0	229	229	912	15.50%	25.13%	40.63%
2021 /22	(g)	984	0	984	0	1	1.0870	1,070	1,467	0	1,467		0	0	1,333	0	263	263	930	15.10%	28.31%	43.41%
2022 /23	(g)	998	0	998	2	1	1.0867	1,083	1,467	0	1,075	RFP Solar	20	150	959	10	26	37	944	14.90%	3.88%	18.78%
2023 /24		1 015	0	1,015	2	1	1.0860	1,100	1 075	0	1,075	101 MW Solar	101	100	959	62	(42)	20	961	14.80%	2.10%	16.90%
2024 /25		960	12	972	6	1	1.0860	1,050	1,075	0	1,075	152 MW Solar	152	0	959	140	(91)	48	920	14.80%	5.26%	20.06%

Notes:
(a) Based on June 2019 Load Forecast - Management Update September 2019 (with implied PJM diversity factor)
(b) Projected "Passive" EE, DG, and VVO. DSM is included in the PJM forecast.
(c) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR
(d) Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)
(e) Reflects the members ownership ratio of summer capability.
(f) Based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year
(g) PJM forecast

DATA REQUEST

6 A list that identifies scheduled outages or retirements of generating capacity during the current year and the following four years.

RESPONSE

For a list of scheduled outages for the years 2020 - 2024, please see attachments KPCO_R_KPSC_1_6_Attachment1 and KPCO_R_KPSC_1_6_Public_Attachment2.

The Rockport Unit Power Agreement with AEP Generating Company (AEG), under which the Company purchases 30% of AEG's 50% share of the output of the Rockport Plant (393 MW), expires in December 2022.

Witness: Brian K. West

Kentucky Power Generating Unit
Scheduled Outages for the Period
January - March 2020

Unit Name	Event Start	Event End	Event Description
Big Sandy 1	1/6/20 9:00 AM	1/8/20 10:20 AM	Remove the Generator Hydrogen Meter
Big Sandy 1	2/1/20 1:53 AM	2/4/20 12:00 AM	Boiler inspection and repair
Big Sandy 1	2/14/20 7:00 AM	2/19/20 4:00 PM	Circ Water System Repairs
Mitchell 1	1/2/20 4:00 AM	1/7/20 11:00 PM	Phase 3 Main Transformer Oil Cooler, Absorber Agitator seal replacement.
Mitchell 1	1/7/20 11:00 PM	1/9/20 2:20 PM	Inspect and repair 12 ID Fan Hub, Control Board Replacement for the Voltage Regulator
Mitchell 1	1/12/20 7:00 AM	1/21/20 9:08 AM	Inspect and repair 200lb Header Check Valve, replace 2 Isolation Valves on River Water System, and inspect and repair ID Fan hydraulic Pressure Swings
Mitchell 1	1/23/20 11:59 PM	1/27/20 1:53 AM	Inspect and repair Hydraulic System to the ID Fan.
Mitchell 1	3/26/20 6:00 AM	4/10/20 11:00 PM	PA Duct expansion joint repair, T11 Bearing Oil Leak inspection and repair, FMO-75 repair packing leak, Precipitator inspection and repair, Check ID Fan Hub Oil levels, BMO-3 repack, Main & Aux Condenser Leak check & repair, repack Main Steam Attemperator root valve, inspect and repair Oxidation Air Blower A discharge check valve, replace cracked LP Turbine Rupture Diaphragms
Mitchell 2	1/12/20 7:00 AM	1/16/20 3:14 PM	ID Fan Hub oil level checks, replace 2 isolation valves on the River Water Make Up system, replace Plant Air/Control Air isolation valve
Mitchell 2	3/19/20 11:55 PM	3/25/20 11:00 PM	Inspect and repair Hydrogen Cooler leak on the inlet piping to #3 hydrogen cooler. Boiler leak check, Waste Water Sump Discharge Header repairs, Waste Water Sump Ring Header repairs, Condenser leak, Precipitator inspect and repair, Trona Bin Vent Filter, Oxy Air Blower C PM, Boiler Safety Valve repair, and Cooling Tower inspection and repairs.
Mitchell 2	3/25/20 11:00 PM	3/30/20 10:48 PM	FGD Service Water Strainer and Bypass Valve, Sparger Vessel Safety valve, Waste Water Sump Discharge Discharge Header inspection and repair, CO2 Tank Hand Shutoff packing repairs, Coal handling feed Throw Over Switch repairs, work on ARV-542 Hand Shut-off Valve

Kentucky Power Generating Unit
Scheduled Outages for the Period
April 2020 - December 2024

Plant	Unit	Estimated Start Date	Estimated End Date
BIG SANDY	1	[redacted]	
BIG SANDY	1		
BIG SANDY	1		
BIG SANDY	1		
BIG SANDY	1		
BIG SANDY	1		
BIG SANDY	1		
BIG SANDY	1		
BIG SANDY	1		
MITCHELL	1		
MITCHELL	1		
MITCHELL	1		
MITCHELL	1		
MITCHELL	1		
MITCHELL	2		
MITCHELL	2		
MITCHELL	2		
MITCHELL	2		
MITCHELL	2		

DATA REQUEST

7 Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected inservice date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky. Please provide the information for both Kentucky Power Company individually and the AEP-East Power Pool (pursuant to the Commission's December 13, 2004 Order in the Rockport UPSA extension, Case No. 2004-00420).

RESPONSE

Kentucky Power does not currently plan to add base load or peaking capacity to meet native load requirements over the next 10 years.

Kentucky Power's 2019 Integrated Resource Plan projected as part of its Preferred Plan the addition of 373 MW of solar and wind resources during the 2020 through 2029 time period, including 20 MW of solar assumed to be installed in 2022. The Preferred Plan is not a commitment by Kentucky Power to the identified resource additions.

The AEP Interconnection Agreement terminated on January 1, 2014 and the AEP-East Power Pool no longer exists. As a result, the requested information regarding the AEP-East Power Pool is no longer available.

Witness: Brian K. West

DATA REQUEST

8 The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:
a. Total energy received from all interconnections and generation sources connected to the transmission system.
b. Total energy delivered to all interconnections on the transmission system.
c. Peak load capacity of the transmission system.
d. Peak demand for summer and winter seasons on the transmission system.

RESPONSE

a,b. Please refer to KPCO_R_KPSC_1_8ab_Attachment1 for the requested information.

c. The maximum amount of electric energy that can be transmitted through a transmission network is a function of the level of the load and generation connected to the transmission system as well as the level and direction of transmission service into, out of, and through the network. Therefore, the 'Peak Load Capacity' of the transmission system cannot be quantified as a single value.

The Kentucky Power transmission system capacity is designed to serve the existing and projected load. It is also designed to reliably serve the load for any single contingency outage of a line, transformer or generator. Based on information currently available, the existing transmission system, together with the transmission capacity additions described in KPCO_R_KPSC_1_9_Confidential_Attachment1, will provide adequate capacity to serve the existing and projected loads provided in response to part d of this request.

d. Please refer to KPCO_R_KPSC_1_8d_Attachment1 for the requested information.

Witness: Brian K. West

8(a) All quantities represent metered values.

Received from (MWh):	2014 (Actual)	2015 (Actual)	2016 (Actual)	2017 (Actual)	2018 (Actual)	2019 (Actual)	2020	
Appalachian Power (1)	5,171,726	4,017,819	4,720,669	5,890,958	4,684,108	4,955,996	(4)	
Ohio Power (1)	9,354,195	9,802,944	9,333,487	8,911,083	8,311,169	7,230,181	(4)	
East Ky Power Coop	294,361	271,558	300,264	281,573	255,874	198,148	(4)	
LGE(Kentucky Utilities)	623,285	533,642	392,126	372,296	514,195	342,790	(4)	
TVA	460,644	431,204	310,003	328,457	434,753	302,290	(4)	
Illinois Power Co. (2)	84,189	380,121	319,112	257,896	429,424	260,628	(5)	
Illinois Power Co. (3)	67,185	193,480	204,194	173,916	261,051	115,155	(5)	
Big Sandy Generating Plant	4,708,473	3,132,143	530,333	563,778	624,804	1,062,893	1,077,841	
Mitchell 1&2 (KPCo Share 50%)	4,096,020	2,688,981	3,814,606	3,820,609	2,714,974	2,481,963	3,483,064	(7)
Rockport (KPCo Share 15%)	2,507,564	1,866,891	1,727,064	1,631,917	1,777,423	1,211,457	1,569,689	(7)

8(b) All quantities represent metered values.

Delivered to (MWh) :	2014	2015	2016	2017	2018	2019	2020
Appalachian Power (1)	13,038,290	11,369,584	9,073,136	10,111,259	8,585,984	7,849,765	(4)
Ohio Power (1)	433,763	440,883	509,828	454,121	435,997	454,329	(4)
East Ky Power Coop	236,884	240,042	291,229	245,640	289,530	304,324	(4)
LGE(Kentucky Utilities)	0	0	0	0	0	0	(4)
TVA	0	0	0	0	0	0	(4)
Illinois Power Co. (2)	0	0	0	0	0	0	(5)
Illinois Power Co. (3)	0	0	0	0	0	0	(5)
Vanceburg and Olive Hill	96,494	90,532	85,455	80,426	86,019	84,250	(6)

Notes: (1) An AEP System company.
(2) At the Riverside independent power producing plant (IPP) in Lawrence County, KY.
(3) At the Foothills independent power producing plant (IPP) in Lawrence County, KY.
(4) The Company does not forecast metered interchange; however, the future years' energy flows are not expected to be materially different from the year 2015 actuals.
(5) The Company does not, and can not, forecast energy production output from an IPP.
(6) This is a 3rd Party Firm Load that is served by Kentucky Power
(7) Net Generation less Non-generating auxiliaries shares from Mitchell Power Plant and Rockport are from Plants not directly connected to the KPCo system

Kentucky Power Company
Seasonal Peak Demand
Actual 2019 and Forecast 2020-2024

Year	Summer Peak Demand (MW)	Preceding Winter Peak Demand (MW)
2019	993*	1,297*
2020	1,004	1,295
2021	1,002	1,293
2022	998	1,288
2023	995	1,280
2024	992	1,273

***Based on Actual Data**

DATA REQUEST

9 Identify all planned transmission capacity additions for the next 10 years. Include the expected in-service date, size and site for all planned additions and identify the transmission need each addition is intended to address.

RESPONSE

Please see KPCO_R_KPSC_1_9_Confidential_Attachment1 for the requested information.

Witness: Brian K. West

***ALL CAPACITIES AND IN SERVICE DATES APPROXIMATE/SUBJECT TO CHANGE**

Hazard – Wooton 161 kV Project – This project addresses thermal violations, equipment material condition, performance, and risk concerns identified with the Hazard-Wooton 161 kV line and 161/138 kV transformer. Specifically, this project will rebuild approximately 6.6 miles of the Hazard - Wooton 161 kV line and replace three, single phase 161/138 kV transformers at Hazard with a single higher capacity three-phase transformer. Additionally, this project will replace the existing 138/69 kV transformers with new 138/69 kV 130 MVA transformers due to identified equipment material condition, performance, and risk concerns. The revised in-service date for this project is June 2021.

Hazard – Wooton 161 kV Line
Existing Summer Emergency Conductor Capacity: 215 MVA
Proposed Summer Emergency Conductor Capacity: 390 MVA

Hazard 161/138 kV Transformer
Existing Nameplate Capacity: 135 MVA
Proposed Nameplate Capacity: 350 MVA

Hazard 138/69 kV Transformer #1
Existing Nameplate Capacity: 50 MVA
Proposed Nameplate Capacity: 130 MVA

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Leslie Transformer Replacement – This project will replace the 161/69 kV transformer at Leslie station. The transformer is being replaced due to insulation and short circuit strength breakdown. Current projected in-service date for the transformer replacement is December 2021.

Leslie Transformer

Existing Nameplate Capacity: 90 MVA
Proposed Nameplate Capacity: 130 MVA

East Park 138 kV Transmission Line – This project will construct approximately 3 miles of 138 kV line to connect the existing Chadwick – Kentucky Electric Steel 138 kV line to the proposed Moore Hollow 138 kV substation located in the East Park Industrial Center. The project will serve as a transmission service delivery point to industrial customers at the East Park Industrial Center. The Current in-service date is dependent on the customer and has yet to be determined

East Park 138 kV transmission line

Proposed Summer Emergency Conductor Capacity: 413 MVA

Boyd County Area Improvements - This project will construct approximately 8 miles of 138 kV line to connect the proposed Moore Hollow 138 kV substation located in the East Park Industrial Center to the proposed Ramey substation off the existing Bellefonte – Grangston 138 kV circuit. The project will serve as the second transmission source to industrial customers at the East Park Industrial Center. The project also addresses equipment material condition performance, and risk concerns associated with the Hoods Creek Station, while establishing a new distribution source to the area at Ramey. The Current in-service date is dependent on the customer and has yet to be determined

Moore Hollow - Ramey 138 kV transmission line

Proposed Summer Emergency Conductor Capacity: 413 MVA

Chadwick Station Improvements and Leach Area Improvements – This project will Expand existing Chadwick station and install a second 138/69 kV transformer at a new 138 kV bus tied into the Bellefonte – Grangston 138 kV circuit. The 69 kV bus will be reconfigured into a ring bus arrangement to tie the new transformer into the existing 69 kV via installation of four 3000A 63 kA 69 kV circuit breakers. Remote end will be required at Grangston station. Remote end will be required at Bellefonte station. Relocate the Chadwick – Leach 69 kV circuit within Chadwick station. The Bellefonte – Grangston 138 kV circuit currently spans over top of Chadwick station, but does not terminate. Work will be completed to bring the circuit into Chadwick station at the newly established 138 kV bus. The existing Chadwick – Tri-State #2 138 kV circuit will be reconfigured within the station to terminate into the newly established 138 kV bus #2 at Chadwick due to construability aspects. Chadwick – Leach and Chadwick England Hill 69 kV circuits (share same structures for majority of circuits). Reconductor circuits with 795 ACSS conductor. A LiDAR survey and a sag study will need to be performed to confirm that the reconductored circuits would maintain acceptable clearances. Replace line risers towards Leach station. Replace 20 kA 69 kV circuit breaker 'F' with a new 3000A 40 kA 69 kV circuit breaker. Rebuild 336 ACSR portion of Leach - Miller S.S 69 kV line section (~0.3 miles). Replace line risers towards Chadwick station. The proposed project in-service date is November 2021.

Chadwick Transformer #2

Proposed Nameplate Capacity: 200 MVA

Chadwick – England Hill 69 kV transmission line

Proposed Summer Emergency Conductor Capacity: 413 MVA

Chadwick – Leach 69kV transmission line

Proposed Summer Emergency Conductor Capacity: 413 MVA

[redacted]

[redacted]

[redacted]

Enterprise Park Area Improvements – This project will address thermal and voltage violations identified on the Pikeville 46kV network by establishing a new substation (Kewanee) to the west (~1.5 mi.) of the existing Fords Branch Station, potentially in/near the new Kentucky Enterprise Industrial Park. This new station will consist of 4 -138 kV breaker ring bus and 2 step-down distribution voltage transformers and a 28.8 MVAR Cap Bank. The project will construct approximately 5 miles of new double circuit 138 kV line in order to loop the new substation into the existing Beaver Creek – Cedar Creek 138 kV circuit. Current projected in-service date is September 2023.

Beaver Creek – Kewanee 138kV transmission line
Proposed Summer Emergency Conductor Capacity 378 MVA

Kewanee – Cedar Creek 138kV transmission line
Proposed Summer Emergency Conductor Capacity 378 MVA

Middle Creek BESS and Middle Creek – Prestonsburg 46kV Rebuild – This project will address needs on ~23 miles of the Falcon – Prestonsburg 46kV circuit. Falcon – Prestonsburg 46kV line consists of 1940s wood structures. As part of the solution, A BESS (Battery Energy Storage Solution) will be installed sat Middle Creek substation. The project will retire ~14.5 miles of 46kV lines between Falcon and Middle Creek substations. The project will rebuild ~8.5 miles of 46kV line between Prestonsburg and Middle Creek station.

Middle Creek BESS
Proposed Nameplate Capacity: 2 MW

Middle Creek – Prestonsburg 46kV transmission line
Existing Summer Emergency Conductor Capacity: 23 MVA
Proposed Summer Emergency Conductor Capacity 70 MVA

Garret Area Improvements – This project will construct ~9.3 miles of single circuit 138kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way. The Project will also construct ~3.5 miles of single circuit 138kV from the Eastern station to Garrett station, a short extension from the new Eastern station to the existing Hays Branch metering point, a short extension to existing Morgan Fork – Hays Branch 138 kV circuit from Eastern station, and a double circuit cut into existing Hays Branch - Morgan Fork line to tie into new Hays Branch S.S PoP switch. The Project will also require installation of a new heavy double circuit dead-end tap structure on the existing Hays Branch – Morgan Fork 138kV Line (Due to unequal loading on the transmission line). In addition, the Garrett station will be expanded to install a 138kV three breaker ring bus (If space becomes a constraint, a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer may be installed), and a 138/12kV 30 MVA transformer. A new 138 kV substation (Eastern) will be constructed south of the existing Hays Branch station and will include two 138kV breakers (3000A 40kA) on exits toward Morgan Fork and Garrett station. Finally, the Project will construct a new Snag Fork Switch Station and install a 3-way phase over phase motorized (automated) switching structure near Saltlick to serve the EKPC co-op. Projected in-service date is October 2023.

Eastern - Garrett 138kV transmission line
Existing Summer Emergency Conductor Capacity: 29-50 MVA
Proposed Summer Emergency Conductor Capacity 253 MVA

Garrett – Soft Shell 138kV transmission line
Existing Summer Emergency Conductor Capacity: 29-50 MVA
Proposed Summer Emergency Conductor Capacity 253 MVA

[redacted]

[redacted]

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Kentucky Power Company	**End of** 2019/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ____________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Power Company	02 Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1 Riverside Plaza, Columbus, OH 43215-2373	
05 Name of Contact Person Jason M. Johnson	06 Title of Contact Person Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Serivce Corp., 1 Riverside Plaza, Columbus, OH 43215-2373	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(614) 716-1000	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Jeffrey W Hoersdig		
02 Title Assistant Controller	Jeffrey W Hoersdig	04/28/2020

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

☐ Two copies will be submitted

☐ No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Jeffrey W. Hoersdig, Assistant Controller
1 Riverside Plaza
Columbus, OH 43215

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Kentucky
July 21, 1919

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

None

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric – Kentucky

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes...Enter the date when such independent accountant was initially engaged:
(2) ☒ No

Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report *(Mo, Da, Yr)* 04/28/2020	Year/Period of Report End of 2019/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

American Electric Power Company, Inc. - Ownership of 100% of Respondent's Common Stock

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Footnote		
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Schedule Page: 104 Line No.: 1 Column: a

Summary Compensation Table

The following table provides summary information concerning compensation earned by our Chief Executive Officer, our Chief Financial Officer and the three other most highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Non-Equity Incentive Plan Compensation ($)(3)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(4)	All Other Compensation ($)(5)	Total ($)
Nicholas K. Akins— Chairman of the Board and Chief Executive Officer	2019	1,475,654	—	8,775,003	3,600,000	530,151	111,628	14,492,436
Brian X. Tierney— Executive Vice President and Chief Financial Officer	2019	793,039	—	4,064,681	1,088,000	470,138	95,560	6,511,418
David M. Feinberg— Executive Vice President, General Counsel and Secretary	2019	677,596	—	1,445,289	865,000	173,983	73,436	3,235,304
Lisa M. Barton— Executive Vice President-Transmission	2019	588,254	—	3,238,802	825,000	173,781	67,799	4,893,636
Lana L. Hillebrand— Executive Vice President-Chief Administrative Officer	2019	615,358	—	1,135,625	800,000	221,245	74,831	2,847,059

(1) Amounts in the salary column are composed of executive salaries earned for the year shown, which include 261 days of pay for 2019. This is one day more than the standard 260 calendar work days and holidays in a year.

(2) The amounts reported in this column reflect the aggregate grant date fair value calculated in accordance with FASB ASC Topic 718 of the performance units and restricted stock units (RSUs) granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2019 for a discussion of the relevant assumptions used in calculating these amounts. The number of shares realized and the value of these performance shares, if any, will depend on the Company's performance during a 3 year performance period. The potential payout can range from 0 percent to 200 percent of the target number of performance shares, plus any dividend equivalents.

The value of the 2019 performance units will be based on two equally weighted measures: a Board approved cumulative operating earnings per share measure (Cumulative EPS) and a total shareholder return measure (Relative TSR). The grant date fair value of the 2019 performance units that are based on Cumulative EPS was computed in accordance with FASB ASC Topic 718 and was measured based on the closing price of AEP's common stock on the date of grant. The maximum amount payable for the 2019 performance units that are based on Cumulative EPS is equal to: $6,374,972 for Mr. Akins; $1,500,026 for Mr. Tierney; $1,050,010 for Mr. Feinberg; $900,032 for Ms. Barton and $825,042 for Ms. Hillebrand. The grant date fair value of the 2019 performance units that are based on Relative TSR is calculated using a Monte-Carlo model as of the date of grant, in accordance with FASB ASC Top 718. Because the performance shares that are based on Relative TSR are subject to market conditions as defined under FASB ASC Topic 718, they did not have a maximum value on the grant date that differed from the grant date fair values presented in the table. Instead, the maximum value is factored into the calculation of the grant date fair value.

(3) The amounts shown in this column are annual incentive compensation paid for the year shown.

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2019 for a discussion of the relevant assumptions.

(5) Amounts shown in the All Other Compensation column for 2019 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company matching contributions to the Company's Supplemental Retirement Savings Plan and (c) perquisites. The amounts are listed in the following table:

Type	Nicholas K. Akins	Brian X. Tierney	David M. Feinberg	Lisa M. Barton	Lana L. Hillebrand
Retirement Savings Plan Match	$ 12,600	$ 12,600	$ 12,600	$ 12,600	$ 12,600
Supplemental Retirement Savings Plan Match	$ 77,400	$ 62,960	$ 47,199	$ 39,613	$ 41,951
Perquisites	$ 21,628	$ 20,000	$ 13,637	$ 15,586	$ 20,280
Total	**$ 111,628**	**$ 95,560**	**$ 73,436**	**$ 67,799**	**$ 74,831**

Perquisites provided in 2019 included: financial counseling and tax preparation services, and, for Mr. Akins, director's group travel accident insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time executive officers may receive customary gifts from third parties that sponsor sporting events (subject to our policies on conflicts of interest).

Mr. Akins has entered into an Aircraft Time Sharing Agreement that allows him to use our corporate aircraft for personal use for a limited number of hours each year. The Aircraft Time Sharing Agreement requires Mr. Akins to reimburse the Company for the cost of his personal use of corporate aircraft in accordance with limits set forth in Federal Aviation Administration regulations. The incremental costs incurred in connection with personal flights for which Mr. Akins fully reimbursed the Company under the Aircraft Timesharing Agreement include fuel, oil, hangar costs, crew travel expenses, catering, landing fees, and other incremental airport fees. Accordingly, no value is shown for these amounts in the Summary Compensation Table. If the aircraft flies empty before picking up or after dropping off Mr. Akins at a destination on a personal flight, the cost of the empty flight is included in the incremental cost for which Mr. Akins reimburses the Company. Since AEP aircraft are used predominantly for business purposes, we do not include fixed costs that do not change in amount based on usage, such as depreciation and pilot salaries.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Nicholas K. Akins, Chairman of the Board	Columbus, Ohio
2	and Chief Executive Officer	
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4	Lisa M. Barton, Vice President	Columbus, Ohio
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6	Brian X. Tierney, Chief Financial Officer	Columbus, Ohio
7	and Vice President	
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9	Mark C. McCullough, Vice President	Columbus, Ohio
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11	Lana L. Hillebrand, Vice President	Columbus, Ohio
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13	David M. Feinberg, Secretary	Columbus, Ohio
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15	Charles R. Patton	Columbus, Ohio
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17	Paul Chodak III, Vice President	Columbus, Ohio
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19	Note: The Respondent does not have an Executive Committee	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[X] Yes
[ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	PJM Interconnection LLC - Attachment H-14	ER17-405
2	Rate Schedule 51	ER06-340
3	Rate Schedule 52	ER06-358
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20191031-5290	10/31/2019	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
2	20190710-5154	07/10/2019	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
3	20190528-5201	05/28/2019	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
4	20190109-5145	01/09/2019	ER17-405	AEP PJM OATT Proj Transmission	PJM OATT Attachment H-14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	204-207	Electric Plant In Service	g	49
2	214	Electric Plant Held for Future Use	d	46
3	216	Construction Work In Progress	b	1
4	219	Accumulated Depreciation	b	21
5	310-311	Sales for Resale	k	1
6	320	Electric Operations & Maintenance Expense	b	5
7	320	Electric Operations & Maintenance Expense	b	25
8	320	Electric Operations & Maintenance Expense	b	31
9	321	Electric Operations & Maintenance Expense	b	93
10	323	Electric Operations & Maintenance Expense	b	185
11	336	Depreciation Expense	b	7
12	354	Distribution of Wages and Salaries	b	28
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Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report 04/28/2020	Year/Period of Report End of 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
Renewed on April 9, 2019	City of Wurtland, Kentucky	Twenty (20) year franchise renewal expiring on April 8, 2039	None
Renewed on April 13, 2019	City of Grayson, Kentucky	Twenty (20) year franchise renewal expiring on August 12, 2039	None
Renewed on October 1, 2019	City of Salyersville, Kentucky	Twenty (20) year franchise renewal expiring on September 30, 2019	None

2. None

3. None

4. None

5. None

6. None

7. None

8. KPCo employees represented by IBEW 978 were provided with a 2.5% + market adjustments effective May 1, 2019.

   KPCo employees represented by UWUA 492 were provided with a 2.5% + market adjustments effective June 1, 2019

9. None

10. None

11. (Reserved)

12. Not Used

13. Julia A. Sloat elected Vice President on 01/01/2019
    D. Brett Mattison elected President and COO on 01/01/2019
    Antonio P. Smyth elected Vice President on 01/29/2019
    Julie Williams resigned as Assistant Controller on 03/08/2019
    Phillips, Everett G elected Vice President as Distribution Region Operations effective on 8/22/2019.

Wiseman, Cynthia G elected Vice President as External Affairs & Customer Services effective on 8/22/2019.
Wohnhas, Ranie K elected Vice President - Regulatory & Finance effective on 08/22/2019.

14. Proprietary capital ratio exceeds 30%

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,880,228,456	2,732,212,005
3	Construction Work in Progress (107)	200-201	98,671,345	84,747,789
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,978,899,801	2,816,959,794
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,026,166,192	969,035,246
6	Net Utility Plant (Enter Total of line 4 less 5)		1,952,733,609	1,847,924,548
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,952,733,609	1,847,924,548
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		6,670,698	6,670,698
19	(Less) Accum. Prov. for Depr. and Amort. (122)		224,833	239,662
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	8,399,493	8,555,112
24	Other Investments (124)		1,887,770	1,941,831
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		23,421,499	15,818,892
30	Long-Term Portion of Derivative Assets (175)		24,821	159,071
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		40,179,448	32,905,942
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		848,841	1,168,118
36	Special Deposits (132-134)		618,051	916,736
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		15,019,912	20,962,767
41	Other Accounts Receivable (143)		145,236	56,964
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		345,516	85,487
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		19,830,389	28,154,531
45	Fuel Stock (151)	227	28,444,250	10,227,377
46	Fuel Stock Expenses Undistributed (152)	227	1,410,788	393,217
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	17,715,041	16,893,820
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	8,695,214	8,868,691

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		8,399,493	8,555,112
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		2,186,136	2,053,322
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		3,024,633	3,216,614
61	Accrued Utility Revenues (173)		13,549,567	8,931,308
62	Miscellaneous Current and Accrued Assets (174)		0	-717
63	Derivative Instrument Assets (175)		6,902,626	5,880,910
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		24,820	159,071
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		109,620,855	98,923,988
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,447,055	2,872,035
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	570,033,797	535,438,073
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,397,985	2,607,414
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	22,094,039	22,937,887
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		434,656	468,307
82	Accumulated Deferred Income Taxes (190)	234	105,810,117	87,019,228
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		702,217,649	651,342,944
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,804,751,561	2,631,097,422

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	50,450,000	50,450,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	526,135,279	526,135,279
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	236	0
11	Retained Earnings (215, 215.1, 216)	118-119	204,805,591	156,505,845
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	789,723	-211,988
16	Total Proprietary Capital (lines 2 through 15)		782,180,357	732,879,136
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	0	0
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	870,000,000	870,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		0	0
24	Total Long-Term Debt (lines 18 through 23)		870,000,000	870,000,000
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		10,730,117	1,928,801
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		260,796	126,563
29	Accumulated Provision for Pensions and Benefits (228.3)		5,420,479	3,885,373
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	195,994
32	Long-Term Portion of Derivative Instrument Liabilities		951	44,160
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		43,587,723	41,681,392
35	Total Other Noncurrent Liabilities (lines 26 through 34)		60,000,066	47,862,283
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		63,349,638	51,022,273
39	Notes Payable to Associated Companies (233)		113,174,766	27,870,529
40	Accounts Payable to Associated Companies (234)		23,448,904	30,615,131
41	Customer Deposits (235)		30,953,803	30,148,826
42	Taxes Accrued (236)	262-263	30,903,196	27,669,270
43	Interest Accrued (237)		6,364,779	6,571,594
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,501,143	2,546,039
48	Miscellaneous Current and Accrued Liabilities (242)		20,515,247	19,949,401
49	Obligations Under Capital Leases-Current (243)		2,731,757	602,175
50	Derivative Instrument Liabilities (244)		1,480,637	139,094
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		951	44,160
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		295,422,919	197,090,172
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		161,327	158,651
57	Accumulated Deferred Investment Tax Credits (255)	266-267	26	86
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	7,208,648	6,751,843
60	Other Regulatory Liabilities (254)	278	262,109,527	287,199,724
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	31,743,080	31,741,027
63	Accum. Deferred Income Taxes-Other Property (282)		265,810,885	258,865,667
64	Accum. Deferred Income Taxes-Other (283)		230,114,726	198,548,833
65	Total Deferred Credits (lines 56 through 64)		797,148,219	783,265,831
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,804,751,561	2,631,097,422

Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	626,387,095	652,136,780		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	336,127,613	349,928,463		
5	Maintenance Expenses (402)	320-323	64,622,217	70,281,532		
6	Depreciation Expense (403)	336-337	85,177,886	83,601,549		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	223,101	222,408		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	5,839,732	5,935,606		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	38,616	38,616		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		6,600,723	7,972,003		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	28,356,538	23,825,830		
15	Income Taxes - Federal (409.1)	262-263	-303,842	2,599,865		
16	- Other (409.1)	262-263	1,683,529	-344,295		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	291,684,028	577,673,738		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	291,481,753	572,859,628		
19	Investment Tax Credit Adj. - Net (411.4)	266	-61	-325		
20	(Less) Gains from Disp. of Utility Plant (411.6)		7,640	9,059		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		188,099	42,641		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		775,812	791,150		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		529,148,400	549,614,812		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		97,238,695	102,521,968		

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
626,387,095	652,136,780					2
						3
336,127,613	349,928,463					4
64,622,217	70,281,532					5
85,177,886	83,601,549					6
223,101	222,408					7
5,839,732	5,935,606					8
38,616	38,616					9
						10
						11
6,600,723	7,972,003					12
						13
28,356,538	23,825,830					14
-303,842	2,599,865					15
1,683,529	-344,295					16
291,684,028	577,673,738					17
291,481,753	572,859,628					18
-61	-325					19
7,640	9,059					20
						21
188,099	42,641					22
						23
775,812	791,150					24
529,148,400	549,614,812					25
97,238,695	102,521,968					26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		97,238,695	102,521,968		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		239,428	201,967		
34	(Less) Expenses of Nonutility Operations (417.1)		1,351	7,478		
35	Nonoperating Rental Income (418)		18,795	6,652		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		37,246	44,263		
38	Allowance for Other Funds Used During Construction (419.1)		1,229,522	2,001,874		
39	Miscellaneous Nonoperating Income (421)		-104,380	556,351		
40	Gain on Disposition of Property (421.1)			121,274		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		1,419,260	2,924,903		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,346			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,724,667	983,796		
46	Life Insurance (426.2)					
47	Penalties (426.3)		225,488	51,962		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		352,901	473,585		
49	Other Deductions (426.5)		4,170,538	3,835,003		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,475,940	5,344,346		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	19,055	28,569		
53	Income Taxes-Federal (409.2)	262-263	-685,791	-1,496,368		
54	Income Taxes-Other (409.2)	262-263	52,253	-218,566		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	977,034	1,687,329		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,904,158	1,042,466		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,541,607	-1,041,502		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-5,515,073	-1,377,941		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		38,337,292	38,166,448		
63	Amort. of Debt Disc. and Expense (428)		425,992	451,488		
64	Amortization of Loss on Reaquired Debt (428.1)		33,651	33,651		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		1,469,943	170,440		
68	Other Interest Expense (431)		423,336	373,262		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,266,338	1,196,994		
70	Net Interest Charges (Total of lines 62 thru 69)		38,423,876	37,998,295		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		53,299,746	63,145,732		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		53,299,746	63,145,732		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		156,505,845	93,416,352
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Implementation of ASU 2018-02			(56,239)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			(56,239)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		53,299,746	63,145,732
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock		-5,000,000	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-5,000,000	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		204,805,591	156,505,845
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)			
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		204,805,591	156,505,845
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	53,299,747	63,145,732
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	91,279,335	89,798,179
5	Amortization of Regulatory Debits and Credits (Net)	6,600,723	7,972,003
6			
7	Mark-to-Market of Risk Management Contracts	319,827	-4,124,666
8	Deferred Income Taxes (Net)	-724,849	5,458,973
9	Investment Tax Credit Adjustment (Net)	-61	-325
10	Net (Increase) Decrease in Receivables	14,630,735	2,555,418
11	Net (Increase) Decrease in Inventory	-20,055,665	7,326,224
12	Net (Increase) Decrease in Allowances Inventory	173,477	256,407
13	Net Increase (Decrease) in Payables and Accrued Expenses	-1,284,880	6,496,055
14	Net (Increase) Decrease in Other Regulatory Assets	-15,808,619	-20,065,483
15	Net Increase (Decrease) in Other Regulatory Liabilities	-10,531,514	3,926,748
16	(Less) Allowance for Other Funds Used During Construction	1,229,522	2,001,874
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-39,664,991	-42,327,206
19	Customer Deposits	804,976	1,705,172
20	Over/Under Recovered Fuel,net	2,601,796	-2,946,587
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	80,410,515	117,174,770
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-163,731,324	-138,017,434
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-1,229,522	-2,001,874
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-263,400	-152,318
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-162,765,202	-136,167,878
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,303,889	627,352
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Contribution in Aid of Construction Proceeds	275,234	896,972
54	(Increase) Decrease in Other Special Deposits	-14,597	-97,173
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-161,200,676	-134,740,727
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		75,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs	-1,011	-502,063
66	Net Increase in Short-Term Debt (c)		
67	Proceed on Capital leaseback	167,658	97,141
68	Notes Payable to Associated Companies	85,304,237	18,229,552
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	85,470,884	92,824,630
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-75,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-5,000,000	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	80,470,884	17,824,630
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-319,277	258,673
87			
88	Cash and Cash Equivalents at Beginning of Period	1,168,118	909,445
89			
90	Cash and Cash Equivalents at End of period	848,841	1,168,118

Schedule Page: 120 Line No.: 18 Column: b

	2019	2018
Utility Plant, Net	$ (14,811,635)	$ (12,756,595)
Property and Investments, Net	39,231	43,349
Margin Deposits	313,282	2,095,032
Prepayments	(1,974,380)	4,417,527
Accrued Utility Revenues, Net	(4,618,259)	(2,264,604)
Miscellaneous Current and Accr Assets	(717)	717
Unamortized Debt Expense	425,992	441,978
Other Deferred Debits, Net	2,171,504	(3,160,096)
Accumulated Provisions - Misc	(107,769)	(347,390)
Current and Accrued Liabilities, Net	(639,830)	(3,847,941)
Other Deferred Credits, Net	(20,462,410)	(26,949,183)
Total	**$ (39,664,991)**	**$ (42,327,206)**

Schedule Page: 120 Line No.: 37 Column: b

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	2019	2018
Sale of meters between various operating companies	$ 52,382	$ 73,849
Sale of transformers between various operating companies	585,283	397,877
Land Sale of 4,055.33+/- acres in Catahoula Parish, LA	-	155,626
Sale of switch KYPCo-T to AEP KYTr Baker 765/345kV Substation (CAT ID 0072654003). Switch was purchased on KYPCo-T inadvertently instead of AEP KYTr	221,807	
Sale Transformer S/N 4100071 (CAT ID 0069040240) to APCO (Darrah Substation) from Kentucky Pwr (Baker 765KV Substation)	444,417	
Total	$ 1,303,889	$ 627,352

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP	American Electric Power Company, Inc., an investor-owned electric public utility holding company which includes American Electric Power Company, Inc. (Parent) and majority owned subsidiaries and affiliates.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KGPCo, KPCo, OPCo and WPCo.
AEP System	American Electric Power System, an electric system, owned and operated by AEP subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AEPTCo	AEP Transmission Company, LLC, a wholly-owned subsidiary of AEP Transmission Holdco, is an intermediate holding company that owns the State Transcos.

AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a competitive AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ASU	Accounting Standards Update.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
Excess ADIT	Excess accumulated deferred income taxes.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
ITC	Investment Tax Credit.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_X	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefits.
OTC	Over the counter.
Parent	American Electric Power Company, Inc., the equity owner of AEP subsidiaries within the AEP consolidation.

PCA	Power Coordination Agreement among APCo, I&M, KPCo and WPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
Risk Management Contracts	Trading and non-trading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, as amended, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
Tax Reform	On December 22, 2017, President Trump signed into law legislation referred to as the "Tax Cuts and Jobs Act" (the TCJA). The TCJA includes significant changes to the Internal Revenue Code of 1986, including a reduction in the corporate federal income tax rate from 35% to 21% effective January 1, 2018.
UPA	Unit Power Agreement.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 165,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. KPCo shared in the revenues and expenses associated with these risk management activities with the member companies.

Under a UPA with AEGCo, an affiliated company, KPCo purchases 390 MWs of Rockport Plant capacity which is 30% of AEGCo's 50% share of the 2,620 MW Rockport Plant. The UPA expires in December 2022. KPCo pays a demand charge for the right to receive the power, which is payable even if the power is not taken.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including KPCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's rates are regulated by the FERC and the KPSC. The FERC also regulates KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The KPSC also regulates certain intercompany transactions under its affiliate statutes. Both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region where the transaction occurs. KPCo has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

The KPSC regulates all of the distribution operations and rates and retail transmission rates on a cost basis. The KPSC also regulates retail generation/power supply operations and rates.

In addition, the FERC regulates the SIA and the Transmission Agreement, which allocate shared system costs and revenues among the utility subsidiaries that are parties to each agreement. The FERC also regulates the PCA. See Note 13 - Related Party Transactions for additional information.

Basis of Accounting

KPCo's accounting is subject to the requirements of the KPSC and the FERC. The financial statements have been prepared in accordance with the Uniform System of Accounts prescribed by the FERC. The principal differences from accounting principles generally accepted in the United States of America (GAAP) include:

- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than as a single amount.
- The classification of accrued taxes as a single amount rather than as assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.

- The classification of finance lease payments as operating activities instead of financing activities.
- The classification of gains/losses from disposition of allowances as utility operating expenses rather than as operating revenues.
- The classification of PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of tax assets related to the accounting guidance for “Uncertainty in Income Taxes” as a reduction to current liabilities rather than a tax benefit.
- The classification of noncurrent tax liabilities related to the accounting guidance for "Uncertainty in Income Taxes" as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities related to the accounting guidance for "Accounting for Income Taxes" as separate assets and liabilities rather than as a single amount.
- The presentation of finance leased assets and their associated accumulated amortization as a single amount instead of as separate amounts.
- The classification of factored accounts receivable expense as a nonoperating expense instead of as an operating expense.
- The classification of certain nonoperating revenues as miscellaneous nonoperating income instead of as operating revenue.
- The classification of certain nonoperating expenses as miscellaneous nonoperating expense instead of as operating expense.
- The separate classification of income tax expense for operating and nonoperating activities instead of as a single income tax expense.
- The classification of coal procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of gas procurement sales as a reduction of fuel expense rather than as revenue.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.
- The classification of debt issuance costs as noncurrent assets instead of noncurrent liabilities.
- The classification of change in emission allowances held for speculation as investing activities instead of operating activities.
- The classification of rents receivable as rents receivable instead of customer accounts receivable.
- The classification of Non-Service Cost Components of Net Periodic Benefit Cost as Operating Expense instead of Other Income (Expense).
- The classification of operating lease assets as Utility Plant rather than as a noncurrent asset.
- The presentation of obligations under finance and operating leases as a single amount in Obligations Under Capital Leases rather than as separate items.
- The classification of interest on regulated finance leases as operating expense instead of other income (expense).

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (deferred revenue reductions or refunds) to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching income with its passage to customers in cost-based regulated rates.

Use of Estimates

The preparation of these financial statements requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to inventory valuation, allowance for doubtful accounts, long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents on the statements of cash flows include Cash on the balance sheets with original maturities of three months or less.

Supplementary Information

	2019	2018
For the Years Ended December 31,	**(in thousands)**	
Cash Was Paid (Received) for:		
Interest (Net of Capitalized Amounts)	$ 38,599	$ 38,671
Income Taxes (Net of Refunds)	84	(3,303)
Noncash Acquisitions Under Capital Leases	1,424	596
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	32,520	21,849

Special Deposits

Special Deposits include funds held by trustees primarily for margin deposits for risk management activities.

Inventory

Fossil fuel inventories and materials and supplies inventories are carried at average cost.

Accounts Receivable

Customer accounts receivable primarily include receivables from wholesale and retail energy customers, receivables from energy contract counterparties related to risk management activities and customer receivables primarily related to other revenue-generating activities.

Revenue is recognized from electric power sales when power is delivered to customers. To the extent that deliveries have occurred but a bill has not been issued, KPCo accrues and recognizes, as Accrued Utility Revenues on the balance sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See "Securitized Accounts Receivables - AEP Credit" section of Note 12 for additional information.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense related to receivables purchased from KPCo under a sale of receivables agreement. For customer accounts receivables relating to risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180-days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180-days may be reserved using specific identification for bad debt reserves.

Concentrations of Credit Risk and Significant Customers

KPCo had a significant customer which accounts for the following percentages of Operating Revenues for the years ended December 31 and Customer Accounts Receivable as of December 31:

Significant Customer of KPCo: **Marathon Petroleum Company**	**2019**	**2018**
Percentage of Total Revenues	12%	12%
Percentage of Customer Accounts Receivable	34%	24%

Management monitors credit levels and the financial condition of KPCo's customers on a continuous basis to minimize credit risk. The KPSC allows recovery in rates for a reasonable level of bad debt costs. Management believes adequate provision for credit loss has been made in the accompanying financial statements.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of removal cost incurred and salvage received. These rates and the related lives are subject to periodic review. The costs of labor, materials and overhead incurred to operate and maintain plant and equipment are included in operating expenses. Removal costs accrued are charged to accumulated depreciation.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the criteria under the accounting guidance for “Impairment or Disposal of Long-Lived Assets.” When it becomes probable that an asset in service or an asset under construction will be abandoned and regulatory cost recovery has been disallowed or is not probable, the cost of that asset shall be removed from plant-in-service or CWIP and charged to expense.

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

The book values of Cash, Special Deposits, Notes Payable to Associated Companies, accounts receivable and accounts payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability.

For commercial activities, exchange-traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange-traded derivatives where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are nonbinding in nature but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket-based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A portion of the Level 3 instruments have been economically hedged which limits potential earnings volatility.

AEP utilizes its trustee's external pricing service to estimate the fair value of the underlying investments held in the benefit plan trusts. AEP's investment managers review and validate the prices utilized by the trustee to determine fair value. AEP's management performs its own valuation testing to verify the fair values of the securities. AEP receives audit reports of the trustee's operating controls and valuation processes.

Assets in the benefits trusts are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Items classified as Level 2 are primarily investments in individual fixed income securities. Fixed income securities generally do not trade on exchanges and do not have an official closing price but their valuation inputs are based on observable market data. Pricing vendors calculate bond valuations using financial models and matrices. The models use observable inputs including yields on benchmark securities, quotes by securities brokers, rating agency actions, discounts or premiums on securities compared to par prices, changes in yields for U.S. Treasury securities, corporate actions by bond issuers, prepayment schedules and histories, economic events and, for certain securities, adjustments to yields to reflect changes in the rate of inflation. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Investments classified as Other are valued using Net Asset Value as a practical expedient. Items classified as Other are primarily cash equivalent funds, common collective trusts, commingled funds, structured products, private equity, real estate, infrastructure and alternative credit investments. These investments do not have a readily determinable fair value or they contain redemption restrictions which may include the right to suspend redemptions under certain circumstances. Redemption restrictions may also prevent certain investments from being redeemed at the reporting date for the underlying value.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Operation Expenses when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel-related revenues over applicable fuel costs incurred) are generally deferred as regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel-related revenues) are generally deferred as regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. FAC deferrals are adjusted when costs are no longer probable of recovery or when refunds of fuel reserves are probable. Changes in fuel costs, including purchased power, are reflected in rates in a timely manner through the FAC. A portion of margins from off-system sales are given to customers through the FAC.

Revenue Recognition

Regulatory Accounting

KPCo's financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses or alternative revenues recognized in accordance with the guidance for "Regulated Operations") and regulatory liabilities (deferred revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and by matching revenue with its passage to customers in cost-based regulated rates.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on its balance sheets. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, KPCo derecognizes that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

KPCo recognizes revenues from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on the statements of income upon delivery of the energy to the customer and includes unbilled as well as billed amounts. Wholesale transmission revenue is based on FERC approved formula rate filings made for each calendar year using estimated costs. The annual rate filing is compared to actual costs with an over- or under-recovery being trued-up with interest and refunded or recovered in a future year's rates. In accordance with the accounting guidance for "Regulated Operations - Revenue Recognition", KPCo recognizes revenue and expense related to the rate true-ups immediately following the annual FERC filings. Any portion of the true-ups applicable to third-parties is recorded as regulatory assets or regulatory liabilities on the balance sheets.

Most of the power produced at KPCo's generation plants is sold to PJM. KPCo purchases power from PJM to supply power to its customers. Generally, these power sales and purchases are reported on a net basis in revenues on the statements of income.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Operation Expenses on the statements of income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's facts and circumstances. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Operation Expenses on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, KPCo records expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in power marketing as a major power producer and participant in electricity markets. KPCo also engages in power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity risk management activities focused on markets where the AEP System owns assets and on adjacent markets. These activities include the purchase-and-sale of energy under forward contracts at fixed and variable prices. These contracts include physical transactions, exchange-traded futures, and to a lesser extent, OTC swaps and options. Certain energy marketing and risk management transactions are with RTOs.

KPCo recognizes revenues and expenses from marketing and risk management transactions that are not derivatives are also recognized upon delivery of the commodity.

KPCo uses MTM accounting for marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or elected normal under the normal purchase normal sale election. The realized gains and losses on marketing and risk management transactions are included in revenues or expense based on the transaction's facts and circumstances. The unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Certain qualifying marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). In the event KPCo designates a cash flow hedge, the cash flow hedge's gain or loss is initially recorded as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on the statements of income. See "Accounting for Cash Flow Hedging Strategies" section of Note 8.

Maintenance

Maintenance costs are expensed as incurred. If it becomes probable that KPCo will recover specifically-incurred costs through future rates, a regulatory asset is established to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues.

Income Taxes and Investment Tax Credits

KPCo uses the liability method of accounting for income taxes. Under the liability method, deferred income taxes are provided for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled. KPCo revalued deferred tax assets and liabilities at the new federal corporate income tax rate of 21% in December 2017. See Note 10 for additional information related to Tax Reform.

When the flow-through method of accounting for temporary differences is reflected in regulated revenues (that is, when deferred taxes are not included in the cost of service for determining regulated rates for electricity), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

KPCo applies the deferral methodology for the recognition of ITC. Deferred ITC is amortized to income tax expense over the life of the asset. Amortization of deferred ITC begins when the asset is placed into service, except where regulatory commissions reflect ITC in the rate-making process, then amortization begins when the cash tax benefit is recognized.

KPCo accounts for uncertain tax positions in accordance with the accounting guidance for “Income Taxes.” KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Penalties on the statements of income. KPCo’s uncertain tax positions are immaterial to the financial statements.

Excise Taxes

As an agent for some state and local governments, KPCo collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not recognize these taxes as revenue or expense.

Debt

Gains and losses from the reacquisition of debt used to finance regulated electric utility plants are deferred and amortized over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If the reacquired debt is refinanced, the reacquisition costs are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates.

Debt discount or premium and debt issuance expenses are deferred and amortized generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations.

Pension and OPEB Plans

KPCo participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all of KPCo's employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees. KPCo accounts for its participation in the AEP sponsored pension and OPEB plans using multiple-employer accounting. See Note 7 - Benefit Plans for additional information including significant accounting policies associated with the plans.

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for the trust funds is to use a diversified portfolio of investments to achieve an acceptable rate of return while managing the investment risk of the assets relative to the associated liabilities. To minimize investment risk, the trust funds are broadly diversified among classes of assets, investment strategies and investment managers. Management regularly reviews the actual asset allocations and periodically rebalances the investments to targeted allocations when appropriate. Investment policies and guidelines allow investment managers in approved strategies to use financial derivatives to obtain or manage market exposures and to hedge assets and liabilities. The investments are reported at fair value under the "Fair Value Measurements and Disclosures" accounting guidance.

Benefit Plans

All benefit plan assets are invested in accordance with each plan's investment policy. The investment policy outlines the investment objectives, strategies and target asset allocations by plan.

The investment philosophies for AEP's benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

- Maintaining a long-term investment horizon.
- Diversifying assets to help control volatility of returns at acceptable levels.
- Managing fees, transaction costs and tax liabilities to maximize investment earnings.
- Using active management of investments where appropriate risk/return opportunities exist.
- Keeping portfolio structure style-neutral to limit volatility compared to applicable benchmarks.
- Using alternative asset classes such as real estate and private equity to maximize return and provide additional portfolio diversification.

The objective of the investment policy for the pension fund is to maintain the funded status of the plan while providing for growth in the plan assets to offset the growth in the plan liabilities. The current target asset allocations are as follows:

Pension Plan Assets	Target
Equity	30%
Fixed Income	54%
Other Investments	15%
Cash and Cash Equivalents	1%

OPEB Plans Assets	Target
Equity	48%
Fixed Income	50%
Cash and Cash Equivalents	2%

The investment policy for each benefit plan contains various investment limitations. The investment policies establish concentration limits for securities and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies or certain commingled funds). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law.

For equity investments, the concentration limits are generally as follows:

- No security in excess of 5% of all equities.
- Cash equivalents must be less than 10% of an investment manager's equity portfolio.
- No individual stock may be more than 10% and 7% for pension and OPEB investments, respectively, of each manager's equity portfolio.
- No securities may be bought or sold on margin or other use of leverage.

For fixed income investments, each investment manager's portfolio is compared to investment grade, diversified long and intermediate benchmark indices.

A portion of the pension assets is invested in real estate funds to provide diversification, add return and hedge against inflation. Real estate properties are illiquid, difficult to value and not actively traded. The pension plan uses external real estate investment managers to invest in commingled funds that hold real estate properties. To mitigate investment risk in the real estate portfolio, commingled real estate funds are used to ensure that holdings are diversified by region, property type and risk classification. Real estate holdings include core, value-added and opportunistic classifications.

A portion of the pension assets is invested in private equity. Private equity investments add return and provide diversification and typically require a long-term time horizon to evaluate investment performance. Private equity is classified as an alternative investment because it is illiquid, difficult to value and not actively traded. The pension plan uses limited partnerships and commingled funds to invest across the private equity investment spectrum. The private equity holdings are with multiple general partners who help monitor the investments and provide investment selection expertise. The holdings are currently comprised of venture capital, buyout and hybrid debt and equity investments.

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for collateral. All loans are collateralized by at least 102% of the loaned asset's market value and the collateral is invested. The difference between the rebate owed to the borrower and the collateral rate of return determines the earnings on the loaned security. The securities lending program's objective is to provide modest incremental income with a limited increase in risk. As of December 31, 2019 and 2018, the fair value of securities on loan as part of the program was $246.3 million and $240.7 million, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned as of December 31, 2019 and 2018.

Trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company is held in the OPEB plan trusts. The strategy for holding life insurance contracts in the taxable Voluntary Employees' Beneficiary Association trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

Cash and cash equivalents are held in each trust to provide liquidity and meet short-term cash needs. Cash equivalent funds are used to provide diversification and preserve principal. The underlying holdings in the cash funds are investment grade money market instruments including commercial paper, certificates of deposit, treasury bills and other types of investment grade short-term debt securities. The cash funds are valued each business day and provide daily liquidity.

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. Comprehensive income (loss) has two components: net income (loss) and other comprehensive income (loss).

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2019 through February 20, 2020, the date that KPCo's 2019 Annual Report was available to be issued, and has updated such evaluation for disclosure purposes through April 21, 2020. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Coronavirus Outbreak

AEP is responding to the global outbreak (pandemic) of the 2019 novel coronavirus (COVID 19) by taking steps to mitigate the potential risks posed by its spread. AEP provides a critical service to its customers which means that it must keep its employees who operate its businesses safe and minimize unnecessary risk of exposure to the virus. AEP has updated and implemented a company-wide pandemic plan to address specific aspects of the coronavirus pandemic. AEP informed both retail customers and state regulators that disconnections for non-payment will be temporarily suspended. This is a rapidly evolving situation that could lead to extended disruption of economic activity in AEP's markets. AEP has instituted measures to ensure its supply chain remains open; however, there could be global shortages that will impact AEP's maintenance and capital programs that AEP cannot currently estimate. AEP will continue to monitor developments affecting both its workforce and its customers, and will take additional precautions that are determined to be necessary in order to mitigate the impacts. AEP continues to implement strong physical and cyber security measures to ensure that its systems remain functional in order to both serve its operational needs with a remote workforce and keep them running to ensure uninterrupted service to customers. AEP will continue to review and modify its plans as conditions change. Extended disruption of economic activity in AEP's markets may result in accounting and disclosure implications for AEP; however, management cannot estimate the potential impact on AEP's financial statements or results of operations. If any of these costs are not recoverable or a significant write-down of assets occur it could reduce future net income and cash flows and impact financial condition.

2. NEW ACCOUNTING STANDARDS

During the FASB's standard-setting process and upon issuance of final standards, management reviews the new accounting literature to determine its relevance, if any, to KPCo's business. The following standards will impact the financial statements.

ASU 2016-02 "Accounting for Leases" (ASU 2016-02)

In February 2016, the FASB issued ASU 2016-02 increasing the transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheets and disclosing key information about leasing arrangements. Under the new standard, an entity must recognize an asset and liability for operating leases on the balance sheets. Additionally, capital leases are known as finance leases going forward. Leases with terms of 12 months or longer are also subject to the new requirements. Fundamentally, the criteria used to determine lease classification remains the same, but is more subjective under the new standard.

New leasing standard implementation activities included the identification of the lease population within the AEP System as well as the sampling of representative lease contracts to analyze accounting treatment under the new accounting guidance. Based upon the completed assessments, management also prepared a gap analysis to outline new disclosure compliance requirements.

Management adopted ASU 2016-02 effective January 1, 2019 by means of a cumulative-effect adjustment to the balance sheets. Management elected the following practical expedients upon adoption:

Practical Expedient	Description
Overall Expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to reassess whether any expired or existing contracts are/or contain leases, do not need to reassess the lease classification for any expired or existing leases and do not need to reassess initial direct costs for any existing leases.
Lease and Non-lease Components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component.
Short-term Lease (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases.
Existing and expired land easements not previously accounted for as leases	Elect optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current leases guidance in Topic 840.
Cumulative-effect adjustment in the period of adoption	Elect the optional transition practical expedient to adopt the new lease requirements through a cumulative-effect adjustment on the balance sheet in the period of adoption.

Management concluded that the result of adoption would not materially change the volume of contracts that qualify as leases going forward. The adoption of the new standard did not materially impact results of operations or cash flows, but did have a material impact on the balance sheets. See Note 11 - Leases for additional disclosures required by the new standard.

ASU 2016-13 "Measurement of Credit Losses on Financial Instruments" (ASU 2016-13)

In June 2016, the FASB issued ASU 2016-13 requiring the recognition of an allowance for expected credit losses for financial instruments within its scope. Examples of financial instruments that are in scope include trade receivables, certain financial guarantees, and held-to-maturity debt securities. The allowance for expected credit losses should be based on historical information, current conditions and reasonable and supportable forecasts. Entities are required to evaluate, and if necessary, recognize expected credit losses at the inception or initial acquisition of a financial instrument (or pool of financial instruments that share similar risk characteristics) subject to ASU 2016-13, and subsequently as of each reporting date. The new standard also revises the other-than-temporary impairment model for available-for-sale debt securities.

Management adopted ASU 2016-13 and its related implementation guidance effective January 1, 2020, by means of a cumulative-effect adjustment to the balance sheet. The adoption of the new standard did not have a material impact to financial position, and had no impact on the results of operations or cash flows. Additionally, the adoption of the new standard did not result in any changes to current accounting systems.

Implementation activities included: (1) the identification and evaluation of the population of financial instruments within the AEP system that are subject to the new standard and, (2) the development of supporting valuation models to also contemplate appropriate metrics for current and supportable forecasted information. As required by ASU 2016-13, the financial instruments subject to the new standard were evaluated on a pool-basis to the extent such financial instruments shared similar risk characteristics.

Management continues to develop disclosures to comply with the requirements of ASU 2016-13 that are required in the first quarter of 2020. Management will continue to monitor for any potential industry implementation issues.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI and details of reclassifications from AOCI for the years ended December 31, 2019 and 2018. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 - Benefit Plans for additional details.

	Pension and OPEB		
For the Year Ended December 31, 2019	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in thousands)	
Balance in AOCI as of December 31, 2018	$ 3,171	$ (3,383)	$ (212)
Change in Fair Value Recognized in AOCI	—	1,039	1,039
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	(223)	—	(223)
Amortization of Actuarial (Gains) Losses	176	—	176
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(47)	—	(47)
Income Tax (Expense) Benefit	(10)	—	(10)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(37)	—	(37)
Net Current Period Other Comprehensive Income (Loss)	(37)	1,039	1,002
Balance in AOCI as of December 31, 2019	$ 3,134	$ (2,344)	$ 790

	Pension and OPEB		
For the Year Ended December 31, 2018	**Amortization of Deferred Costs**	**Changes in Funded Status**	**Total**
		(in thousands)	
Balance in AOCI as of December 31, 2017	$ 3,260	$ (2,998)	$ 262
Change in Fair Value Recognized in AOCI	—	(441)	(441)
Amount of (Gain) Loss Reclassified from AOCI			
Amortization of Prior Service Cost (Credit)	(224)	—	(224)
Amortization of Actuarial (Gains) Losses	111	—	111
Reclassifications from AOCI, before Income Tax (Expense) Benefit	(113)	—	(113)
Income Tax (Expense) Benefit	(24)	—	(24)
Reclassifications from AOCI, Net of Income Tax (Expense) Benefit	(89)	—	(89)
Net Current Period Other Comprehensive Income (Loss)	(89)	(441)	(530)
ASU 2018-02 Adoption	—	56	56
Balance in AOCI as of December 31, 2018	$ 3,171	$ (3,383)	$ (212)

4. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. Rate matters can have a material impact on net income, cash flows and possibly financial condition. KPCo's recent significant rate orders and pending rate filings are addressed in this note.

FERC Transmission Complaint - AEP's PJM Participants

In 2016, seven parties filed a complaint at the FERC that alleged the base return on common equity used by AEP's transmission owning subsidiaries within PJM, including KPCo, in calculating formula transmission rates under the PJM OATT is excessive and should be reduced from 10.99% to 8.32%, effective upon the date of the complaint. In March 2018, AEP's transmission owning subsidiaries within PJM and six of the complainants filed a settlement agreement with the FERC (the seventh complainant abstained). The settlement agreement: (a) established a base return on equity for AEP's transmission owning subsidiaries within PJM of 9.85% (10.35% inclusive of the RTO incentive adder of 0.5%), effective January 1, 2018, (b) required AEP's transmission owning subsidiaries within PJM to provide a onetime refund of $50 million, attributable from the date of the complaint through December 31, 2017, which was credited to customer bills in the second quarter of 2018 and (c) increased the cap on the equity portion of the capital structure to 55% from 50%. As part of the settlement agreement, AEP's transmission owning subsidiaries within PJM, including KPCo, also filed updated transmission formula rates incorporating the reduction in the corporate federal income tax rate due to Tax Reform, effective January 1, 2018 and providing for the amortization of the portion of the Excess ADIT that is not subject to rate normalization requirements over a ten-year period through credits to the federal income tax expense component of the revenue requirement. In May 2019, the FERC approved the settlement agreement.

5. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2019	December 31, 2018	Remaining Recovery Period
	(in thousands)		
Regulatory assets pending final regulatory approval:			
Regulatory Assets Currently Earning a Return			
Kentucky Deferred Purchased Power Expenses	$ 30,165	$ 14,477	
Total Regulatory Assets Currently Earning a Return	30,165	14,477	
Regulatory Assets Currently Not Earning a Return			
Other Regulatory Assets Pending Final Regulatory Approval	1,333	1,148	
Total Regulatory Assets Currently Not Earning a Return	1,333	1,148	
Total Regulatory Assets Pending Final Regulatory Approval	31,498	15,625	
Regulatory assets approved for recovery:			
Regulatory Assets Currently Earning a Return			
Plant Retirement Costs	207,221	210,123	21 years
Plant Retirement Costs - Asset Retirement Obligation Costs	87,359	64,332	21 years
Plant Retirement Costs - Materials and Supplies	3,016	3,016	21 years
Other Regulatory Assets Approved for Recovery	1,105	1,049	various
Total Regulatory Assets Currently Earning a Return	298,701	278,520	
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets Subject to Flow Through	148,847	141,783	20 years
Pension and OPEB Funded Status	43,732	46,613	11 years
Plant Retirement Costs - Asset Retirement Obligation Costs	28,715	28,707	21 years
Storm Related Costs	6,300	8,366	4 years
Environmental Costs	4,348	4,644	2 years
Postemployment Benefits	3,169	2,809	4 years
Under-recovered Fuel Costs	—	2,379	
Other Regulatory Assets Approved for Recovery	4,724	5,992	various
Total Regulatory Assets Currently Not Earning a Return	239,835	241,293	
Total Regulatory Assets Approved for Recovery	538,536	519,813	
Total FERC Account 182.3 Regulatory Assets	$ 570,034	$ 535,438	

Regulatory Liabilities:	**December 31, 2019**	**2018**	**Remaining Refund Period**
	(in thousands)		
Regulatory liabilities pending final regulatory determination:			
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	$ —	$ 1,465	
Total Regulatory Liabilities Pending Final Regulatory Determination	—	1,465	
Regulatory liabilities approved for payment:			
Regulatory Liabilities Currently Not Paying a Return			
PJM Transmission Enhancement Refund	3,149	7,615	6 years
Purchased Power Adjustment Rider	1,190	3,864	2 years
Over-recovered Fuel Costs	223	—	1 year
Unrealized Gain on Forward Commitments	2	4,085	5 years
Other Regulatory Liabilities Approved for Payment	1,306	2,280	various
Total Regulatory Liabilities Currently Not Paying a Return	5,870	17,844	
Income Tax Related Regulatory Liabilities (a)			
Excess ADIT Associated with Certain Depreciable Property	131,393	133,170	(b)
Excess ADIT that is Not Subject to Rate Normalization Requirements	124,847	134,721	17 years
Total Income Tax Related Regulatory Liabilities	256,240	267,891	
Total Regulatory Liabilities Approved for Payment	262,110	285,735	
Total FERC Account 254 Regulatory Liabilities	$ 262,110	$ 287,200	

(a) This balance primarily represents regulatory liabilities for Excess ADIT as a result of the reduction in the corporate federal income tax rate from 35% to 21% related to the enactment of Tax Reform. The regulatory liability balance predominately pays a return due to the inclusion of Excess ADIT in rate base.

(b) Refunded using Average Rate Assumption Method.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against KPCo cannot be predicted. Management accrues contingent liabilities only when management concludes that it is both probable that a liability has been incurred at the date of the financial statements and the amount of loss can be reasonably estimated. When management determines that it is not probable, but rather reasonably possible that a liability has been incurred at the date of the financial statements, management discloses such contingencies and the possible loss or range of loss if such estimate can be made. Any estimated range is based on currently available information and involves elements of judgment and significant uncertainties. Any estimated range of possible loss may not represent the maximum possible loss exposure. Circumstances change over time and actual results may vary significantly from estimates.

For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements.

COMMITMENTS

KPCo has substantial commitments to support its business. KPCo purchases fuel, energy and capacity contracts as part of its normal course of business. Certain contracts contain penalty provisions for early termination.

In accordance with the accounting guidance for "Commitments", the following table summarizes KPCo's actual contractual commitments as of December 31, 2019:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 117,059	$ 143,857	$ 13,666	$ 43,843	$ 318,425
Energy and Capacity Purchase Contracts	52,524	120,879	—	—	173,403
Total	$ 169,583	$ 264,736	$ 13,666	$ 43,843	$ 491,828

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel.

GUARANTEES

Liabilities for guarantees are recorded in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third-parties unless specified below.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of December 31, 2019, there were no material liabilities recorded for any indemnifications.

AEPSC conducts power purchase and sale activity on behalf of APCo, I&M, KPCo and WPCo, who are jointly and severally liable for activity conducted on their behalf.

Lease Obligations

KPCo leases certain equipment under master lease agreements. See “Master Lease Agreements” section of Note 11 for additional information.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. KPCo also maintains property and casualty insurance that may cover certain physical damage or third-party injuries caused by cyber security incidents. Insurance coverage includes all risks of physical loss or damage to assets, subject to insurance policy conditions and exclusions. Covered property generally includes power plants, substations, facilities and inventories. Excluded property generally includes transmission and distribution lines, poles and towers. The insurance programs also generally provide coverage against loss arising from certain claims made by third-parties and are in excess of KPCo’s retentions. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to a cyber security incident. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could reduce future net income and cash flows and impact financial condition.

The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation

By-products from the generation of electricity include materials such as ash, slag and sludge. Coal combustion by-products, which constitute the overwhelming percentage of these materials, are typically treated and deposited in captive disposal facilities or are beneficially utilized. In addition, the generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and non-hazardous materials. KPCo currently incurs costs to dispose of these substances safely.

Superfund addresses clean-up of hazardous substances that are released to the environment. The Federal EPA administers the clean-up programs. Several states enacted similar laws. As of December 31, 2019, there is one site for which KPCo has received an information request which could lead to a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

Management evaluates the potential liability for each site separately, but several general statements can be made about potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often non-hazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named for each site and several of the parties are financially sound enterprises. As of December 31, 2019, management's estimates do not anticipate material clean-up costs for the identified site.

Claims Challenging Transition of American Electric Power System Retirement Plan to Cash Balance Formula

The American Electric Power System Retirement Plan (the Plan) has received a letter written on behalf of four participants (the Claimants) making a claim for additional plan benefits and purporting to advance such claims on behalf of a class. When the Plan's benefit formula was changed in the year 2000, AEP provided a special provision for employees hired before January 1, 2001, allowing them to continue benefit accruals under the then benefit formula for a full 10 years alongside of the new cash balance benefit formula then being implemented. Employees who were hired on or after January 1, 2001 accrued benefits only under the new cash balance benefit formula. The Claimants have asserted claims that (a) the Plan violates the requirements under the Employee Retirement Income Security Act (ERISA) intended to preclude back-loading the accrual of benefits to the end of a participant's career; (b) the Plan violates the age discrimination prohibitions of ERISA and the Age Discrimination in Employment Act (ADEA); and (c) the company failed to provide required notice regarding the changes to the Plan. AEP has responded to the Claimants providing a reasoned explanation for why each of their claims have been denied, and offering an opportunity to appeal those determinations. Management will continue to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see “Fair Value Measurements of Assets and Liabilities” and “Investments Held in Trust for Future Liabilities” sections of Note 1.

KPCo participates in an AEP sponsored qualified pension plan and two unfunded nonqualified pension plans. Substantially all of KPCo’s employees are covered by the qualified plan or both the qualified and nonqualified pension plans. KPCo also participates in OPEB plans sponsored by AEP to provide health and life insurance benefits for retired employees.

KPCo recognizes its funded status associated with defined benefit pension and OPEB plans on its balance sheets. Disclosures about the plans are required by the “Compensation - Retirement Benefits” accounting guidance. KPCo recognizes an asset for a plan’s overfunded status or a liability for a plan’s underfunded status and recognizes, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year that are not recognized as a component of net periodic benefit cost. KPCo records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions used in the measurement of benefit obligations are shown in the following table:

	Pension Plans		OPEB	
	December 31,			
Assumptions	2019	2018	2019	2018
Discount Rate	3.25%	4.30%	3.30%	4.30%
Interest Crediting Rate	4.00%	4.00%	NA	NA
Rate of Compensation Increase	4.70% (a)	4.50% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2019, the rate of compensation increase assumed varies with the age of the employee, ranging from 3% per year to 11.5% per year, with an average increase of 4.7%.

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions used in the measurement of benefit costs are shown in the following table:

	Pension Plans		OPEB	
	Year Ended December 31,			
Assumptions	**2019**	**2018**	**2019**	**2018**
Discount Rate	4.30%	3.65%	4.30%	3.60%
Interest Crediting Rate	4.00%	4.00%	NA	NA
Expected Return on Plan Assets	6.25%	6.00%	6.25%	6.00%
Rate of Compensation Increase	4.60% (a)	4.50% (a)	NA	NA

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

NA Not applicable.

The expected return on plan assets was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation, third party forecasts and current prospects for economic growth.

The health care trend rate assumptions used for OPEB plans measurement purposes are shown below:

	December 31,	
Health Care Trend Rates	**2019**	**2018**
Initial	6.00%	6.25%
Ultimate	4.50%	5.00%
Year Ultimate Reached	2026	2024

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. As of December 31, 2019, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status

For the year ended December 31, 2019, the pension plans had an actuarial loss due to a decrease in the discount rate, partially offset by updates to the mortality table. For the year ended December 31, 2019, the OPEB plans had an actuarial loss due to a decrease in the discount rate and an update to the persistency assumption, partially offset by an update to the projected per capita cost assumption as well as savings resulting from legislation signed in December 2019 which eliminated two Affordable Care Act taxes. For the year ended December 31, 2018, the pension and OPEB plans had an actuarial gain due to an increase in the discount rate as well as updated estimates for future medical expenses in the OPEB plans.

	Pension Plans		OPEB	
	2019	2018	2019	2018
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 173,375	$ 185,395	$ 43,743	$ 48,362
Service Cost	2,844	2,812	261	328
Interest Cost	7,292	6,745	1,856	1,726
Actuarial (Gain) Loss	16,574	(10,039)	3,336	(2,885)
Plan Amendments	—	—	(442)	—
Benefit Payments	(12,000)	(11,538)	(4,619)	(5,184)
Participant Contributions	—	—	1,403	1,381
Medicare Subsidy	—	—	12	15
Benefit Obligation as of December 31,	$ 188,085	$ 173,375	$ 45,550	$ 43,743
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 173,637	$ 188,876	$ 59,238	$ 66,524
Actual Gain (Loss) on Plan Assets	24,770	(3,701)	12,949	(3,484)
Company Contributions	—	—	1	1
Participant Contributions	—	—	1,403	1,381
Benefit Payments	(12,000)	(11,538)	(4,619)	(5,184)
Fair Value of Plan Assets as of December 31,	$ 186,407	$ 173,637	$ 68,972	$ 59,238
Funded (Underfunded) Status as of December 31,	$ (1,678)	$ 262	$ 23,422	$ 15,495

Amounts Recognized on the Balance Sheets

	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
	(in thousands)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ —	$ 324	$ 23,422	$ 15,495
Other Current Liabilities – Accrued Short-term Benefit Liability	(1)	(1)	—	—
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,677)	(61)	—	—
Funded (Underfunded) Status	$ (1,678)	$ 262	$ 23,422	$ 15,495

Amounts Included in Regulatory Assets, Deferred Income Taxes and AOCI

The following table shows the components of the plans included in Regulatory Assets, Deferred Income Taxes and AOCI:

	Pension Plans		OPEB	
	December 31,			
	2019	2018	2019	2018
Components	(in thousands)			
Net Actuarial Loss	$ 47,010	$ 46,316	$ 5,983	$ 12,949
Prior Service Credit	—	—	(10,261)	(12,384)
Recorded as				
Regulatory Assets	$ 45,839	$ 44,992	$ (2,107)	$ 1,621
Deferred Income Taxes	246	278	(456)	(222)
Net of Tax AOCI	925	1,046	(1,715)	(834)

Components of the change in amounts included in Regulatory Assets, Deferred Income Taxes and AOCI were as follows:

	Pension Plans		OPEB	
	2019	2018	2019	2018
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ 2,714	$ 4,268	$ (6,113)	$ 4,541
Amortization of Actuarial Loss	(2,020)	(3,019)	(853)	(362)
Prior Service Credit	—	—	(302)	—
Amortization of Prior Service Cost (Credit)	—	(1)	2,425	2,424
Change for the Year Ended December 31,	$ 694	$ 1,248	$ (4,843)	$ 6,603

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return.

Pension and OPEB Assets

The fair value tables within Pension and OPEB Assets present the classification of assets for AEP within the fair value hierarchy. All Level 1, 2, 3 and Other amounts can be allocated to KPCo using the percentages below:

Pension Plan		OPEB	
December 31,			
2019	2018	2019	2018
3.7%	3.7%	3.9%	3.9%

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 387.8	$ —	$ —	$ —	$ 387.8	7.8 %
International	609.1	—	—	—	609.1	12.1 %
Common Collective Trusts (c)	—	—	—	547.3	547.3	10.9 %
Subtotal – Equities	996.9	—	—	547.3	1,544.2	30.8 %
Fixed Income (a):						
United States Government and Agency Securities	(5.8)	1,248.6	—	—	1,242.8	24.8 %
Corporate Debt	—	1,143.7	—	—	1,143.7	22.8 %
Foreign Debt	—	211.6	—	—	211.6	4.2 %
State and Local Government	—	55.1	—	—	55.1	1.1 %
Other – Asset Backed	—	3.6	—	—	3.6	0.1 %
Subtotal – Fixed Income	(5.8)	2,662.6	—	—	2,656.8	53.0 %
Infrastructure (c)	—	—	—	85.8	85.8	1.7 %
Real Estate (c)	—	—	—	239.4	239.4	4.8 %
Alternative Investments (c)	—	—	—	448.3	448.3	8.9 %
Cash and Cash Equivalents (c)	—	24.4	—	37.2	61.6	1.2 %
Other – Pending Transactions and Accrued Income (b)	—	—	—	(20.7)	(20.7)	(0.4)%
Total	$ 991.1	$ 2,687.0	$ —	$ 1,337.3	$ 5,015.4	100.0 %

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.

(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.

(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2019:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 312.2	$ —	$ —	$ —	$ 312.2	17.5%
International	251.5	—	—	—	251.5	14.1%
Common Collective Trusts (b)	—	—	—	260.8	260.8	14.7%
Subtotal – Equities	563.7	—	—	260.8	824.5	46.3%
Fixed Income:						
Common Collective Trust Debt (b)	—	—	—	177.6	177.6	10.0%
United States Government and Agency Securities	(0.1)	214.4	—	—	214.3	12.0%
Corporate Debt	—	206.7	—	—	206.7	11.6%
Foreign Debt	—	35.5	—	—	35.5	2.0%
State and Local Government	58.8	14.8	—	—	73.6	4.1%
Other – Asset Backed	—	0.2	—	—	0.2	—%
Subtotal – Fixed Income	58.7	471.6	—	177.6	707.9	39.7%
Trust Owned Life Insurance:						
International Equities	—	60.2	—	—	60.2	3.4%
United States Bonds	—	151.6	—	—	151.6	8.5%
Subtotal – Trust Owned Life Insurance	—	211.8	—	—	211.8	11.9%
Cash and Cash Equivalents (b)	26.7	—	—	6.7	33.4	1.9%
Other – Pending Transactions and Accrued Income (a)	—	—	—	4.2	4.2	0.2%
Total	$ 649.1	$ 683.4	$ —	$ 449.3	$ 1,781.8	100.0%

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of pension plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities (a):						
Domestic	$ 277.3	$ —	$ —	$ —	$ 277.3	5.9%
International	384.1	—	—	—	384.1	8.2%
Options	—	18.3	—	—	18.3	0.4%
Common Collective Trusts (c)	—	—	—	370.1	370.1	7.9%
Subtotal – Equities	661.4	18.3	—	370.1	1,049.8	22.4%
Fixed Income (a):						
United States Government and Agency Securities	0.2	1,512.5	—	—	1,512.7	32.2%
Corporate Debt	—	1,082.9	—	—	1,082.9	23.0%
Foreign Debt	—	221.6	—	—	221.6	4.7%
State and Local Government	—	28.2	—	—	28.2	0.6%
Other – Asset Backed	—	7.4	—	—	7.4	0.2%
Subtotal – Fixed Income	0.2	2,852.6	—	—	2,852.8	60.7%
Infrastructure (c)	—	—	—	72.2	72.2	1.5%
Real Estate (c)	—	—	—	220.4	220.4	4.7%
Alternative Investments (c)	—	—	—	444.6	444.6	9.5%
Cash and Cash Equivalents (c)	(0.4)	36.3	—	11.9	47.8	1.0%
Other – Pending Transactions and Accrued Income (b)	—	—	—	8.3	8.3	0.2%
Total	$ 661.2	$ 2,907.2	$ —	$ 1,127.5	$ 4,695.9	100.0%

(a) Includes investment securities loaned to borrowers under the securities lending program. See the "Investments Held in Trust for Future Liabilities" section of Note 1 for additional information.
(b) Amounts in "Other" column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(c) Amounts in "Other" column represent investments for which fair value is measured using net asset value per share.

The following table presents the classification of OPEB plan assets for AEP within the fair value hierarchy as of December 31, 2018:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 233.3	$ —	$ —	$ —	$ 233.3	15.2 %
International	185.9	—	—	—	185.9	12.1 %
Options	—	4.3	—	—	4.3	0.3 %
Common Collective Trusts (b)	—	—	—	226.2	226.2	14.7 %
Subtotal – Equities	419.2	4.3	—	226.2	649.7	42.3 %
Fixed Income:						
Common Collective Trust – Debt (b)	—	—	—	163.6	163.6	10.7 %
United States Government and Agency Securities	0.2	181.5	—	—	181.7	11.8 %
Corporate Debt	—	188.6	—	—	188.6	12.3 %
Foreign Debt	—	35.0	—	—	35.0	2.3 %
State and Local Government	41.8	11.8	—	—	53.6	3.5 %
Other – Asset Backed	—	0.2	—	—	0.2	— %
Subtotal – Fixed Income	42.0	417.1	—	163.6	622.7	40.6 %
Trust Owned Life Insurance:						
International Equities	—	49.4	—	—	49.4	3.2 %
United States Bonds	—	154.4	—	—	154.4	10.1 %
Subtotal – Trust Owned Life Insurance	—	203.8	—	—	203.8	13.3 %
Cash and Cash Equivalents (b)	54.4	—	—	4.8	59.2	3.9 %
Other – Pending Transactions and Accrued Income (a)	—	—	—	(1.2)	(1.2)	(0.1)%
Total	$ 515.6	$ 625.2	$ —	$ 393.4	$ 1,534.2	100.0 %

(a) Amounts in “Other” column primarily represent accrued interest, dividend receivables and transactions pending settlement.
(b) Amounts in “Other” column represent investments for which fair value is measured using net asset value per share.

Accumulated Benefit Obligation

The accumulated benefit obligation for the pension plans is as follows:

	December 31, 2019	December 31, 2018
	(in thousands)	
Qualified Pension Plan	$ 182,529	$ 167,534
Nonqualified Pension Plan	12	12
Total Accumulated Benefit Obligation	$ 182,541	$ 167,546

Obligations in Excess of Fair Values

The tables below show the underfunded pension plans that had obligations in excess of plan assets.

Projected Benefit Obligation

	December 31, 2019	December 31, 2018
	(in thousands)	
Projected Benefit Obligation	$ 188,085	$ 62
Fair Value of Plan Assets	186,407	—
Underfunded Projected Benefit Obligation	$ (1,678)	$ (62)

Accumulated Benefit Obligation

	December 31, 2019	December 31, 2018
	(in thousands)	
Accumulated Benefit Obligation	$ 12	$ 12
Fair Value of Plan Assets	—	—
Underfunded Accumulated Benefit Obligation	$ (12)	$ (12)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the OPEB plans of $1 thousand and $48 thousand, respectively, during 2020. The estimated contributions to the pension trust are at least the minimum amount required by the Employee Retirement Income Security Act and additional discretionary contributions may also be made to maintain the funded status of the plan.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Estimated Payments	
	Pension Plans	OPEB
	(in thousands)	
2020	$ 12,529	$ 5,055
2021	12,596	4,965
2022	12,665	4,975
2023	12,707	4,854
2024	12,920	4,798
Years 2025 to 2029, in Total	63,732	22,499

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit):

	Pension Plans		OPEB	
	Years Ended December 31,			
	2019	2018	2019	2018
	(in thousands)			
Service Cost	$ 2,844	$ 2,812	$ 261	$ 328
Interest Cost	7,292	6,745	1,856	1,726
Expected Return on Plan Assets	(10,910)	(10,605)	(3,639)	(3,944)
Amortization of Prior Service Cost (Credit)	—	1	(2,425)	(2,424)
Amortization of Net Actuarial Loss	2,020	3,019	853	362
Net Periodic Benefit Cost (Credit)	1,246	1,972	(3,094)	(3,952)
Capitalized Portion	(1,195)	(1,069)	(110)	(125)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 51	$ 903	$ (3,204)	$ (4,077)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $2.2 million in 2019 and $2.3 million in 2018.

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

AEPSC is agent for and transacts on behalf of KPCo.

KPCo is exposed to certain market risks as a major power producer and participant in the electricity, natural gas, coal and emission allowance markets. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. Management utilizes derivative instruments to manage these risks.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

The strategy surrounding the use of derivative instruments primarily focuses on managing risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. The risk management strategies also include the use of derivative instruments for trading purposes which focus on seizing market opportunities to create value driven by expected changes in the market prices of the commodities. To accomplish these objectives, KPCo primarily employs risk management contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, OTC swaps and options. Not all risk management contracts meet the definition of a derivative under the accounting guidance for “Derivatives and Hedging.” Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

KPCo utilizes power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. KPCo utilizes interest rate derivative contracts in order to manage the interest rate exposure associated with its commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. KPCo may also utilize derivative contracts to manage interest rate risk associated with debt financing. For disclosure purposes, these risks are grouped as “Interest Rate.” The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of the Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		Unit of
Primary Risk Exposure	2019	2018	Measure
	(in thousands)		
Commodity:			
Power	11,383	12,140	MWhs
Natural Gas	—	698	MMBtus
Heating Oil and Gasoline	273	329	Gallons

Cash Flow Hedging Strategies

KPCo utilizes cash flow hedges on certain derivative transactions for the purchase-and-sale of power ("Commodity") in order to manage the variable price risk related to forecasted purchases and sales. Management monitors the potential impacts of commodity price changes and, where appropriate, enters into derivative transactions to protect profit margins for a portion of future electricity sales and purchases. KPCo does not hedge all commodity price risk.

KPCo may utilize a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo may also utilize interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. KPCo does not hedge all interest rate exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON KPCo's FINANCIAL STATEMENTS

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

Credit risk is the risk that a counterparty will fail to perform on the contract or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to vary from estimated fair value based upon prevailing market supply and demand conditions. Since energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value risk management contracts. Unforeseen events may cause reasonable price curves to differ from actual price curves throughout a contract's term and at the time a contract settles. Consequently, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's estimates of current market consensus for forward prices in the current period. This is particularly true for longer term contracts. Cash flows may vary based on market conditions, margin requirements and the timing of settlement of risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2019 and 2018 balance sheets, KPCo netted $129 thousand and $227 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $150 thousand and $117 thousand, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value of KPCo's derivative activity on the balance sheets:

Fair Value of Derivative Instruments

December 31, 2019

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Derivative Instrument Assets	$ 21,813	$ (14,910)	$ 6,903
Long-term Portion of Derivative Instrument Assets	160	(135)	25
Derivative Instrument Liabilities	16,413	(14,932)	1,481
Long-term Portion of Derivative Instrument Liabilities	128	(127)	1

Fair Value of Derivative Instruments

December 31, 2018

Balance Sheet Location	Risk Management Contracts – Commodity (a)	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
		(in thousands)	
Derivative Instrument Assets	$ 15,976	$ (10,095)	$ 5,881
Long-term Portion of Derivative Instrument Assets	546	(387)	159
Derivative Instrument Liabilities	10,124	(9,985)	139
Long-term Portion of Derivative Instrument Liabilities	430	(386)	44

(a) Derivative instruments within this category are reported gross. These instruments are subject to master netting agreements and are presented on the balance sheets on a net basis in accordance with the accounting guidance for "Derivatives and Hedging."

(b) Amounts include counterparty netting of risk management and hedging contracts and associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging."

(c) All derivative contracts subject to a master netting arrangement or similar agreement are offset in the statement of financial position.

The table below presents KPCo's activity of derivative risk management contracts:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2019	2018
	(in thousands)	
Operating Revenues	$ 72	$ (530)
Operation Expenses	93	198
Maintenance Expenses	(32)	79
Other Regulatory Assets (a)	(416)	(155)
Other Regulatory Liabilities (a)	4,577	12,090
Total Gain on Risk Management Contracts	$ 4,294	$ 11,682

(a) Represents realized and unrealized gains and losses subject to regulatory accounting treatment.

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in the accounting guidance for "Derivatives and Hedging." Derivative contracts that have been designated as normal purchases or normal sales under that accounting guidance are not subject to MTM accounting treatment and are recognized on the statements of income on an accrual basis.

The accounting for the changes in the fair value of a derivative instrument depends on whether it qualifies for and has been designated as part of a hedging relationship and further, on the type of hedging relationship. Depending on the exposure, management designates a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. Certain derivatives that economically hedge future commodity risk are recorded in the same expense line item on the statements of income as that of the associated risk. However, unrealized and some realized gains and losses for both trading and non-trading derivative instruments are recorded as regulatory assets (for losses) or regulatory liabilities (for gains) in accordance with the accounting guidance for "Regulated Operations."

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows that is attributable to a particular risk), KPCo initially reports the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income on the balance sheets until the period the hedged item affects Net Income.

Realized gains and losses on derivative contracts for the purchase-and-sale of power designated as cash flow hedges are included in Operating Revenues or Operation Expenses on KPCo's statements of income or in Other Regulatory Assets or Other Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During the years ended 2019 and 2018 KPCo did not apply cash flow hedging to outstanding power derivatives.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income on its balance sheets into Interest on Long-term Debt on its statements of income in those periods in which hedged interest payments occur. During the years ended 2019 and 2018, KPCo did not apply cash flow hedging to outstanding interest rate derivatives.

There was no impact of cash flow hedges included in Accumulated Other Comprehensive Income on KPCo's balance sheets as of December 31, 2019 and 2018.

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income to Net Income can differ due to market price changes. As of December 31, 2019, KPCo was not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

Management mitigates credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

Master agreements are typically used to facilitate the netting of cash flows associated with a single counterparty and may include collateral requirements. Collateral requirements in the form of cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. Some master agreements include margining, which requires a counterparty to post cash or letters of credit in the event exposure exceeds the established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with AEP's credit policy. In addition, master agreements allow for termination and liquidation of all positions in the event of a default including failure or inability to post collateral when required.

Collateral Triggering Events

Credit Downgrade Triggers

A limited number of derivative contracts include collateral triggering events, which include a requirement to maintain certain credit ratings. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering events in contracts. KPCo has not experienced a downgrade below a specified credit rating threshold that would require the posting of additional collateral. As of December 31, 2019 and 2018, KPCo did not have derivative contracts with collateral triggering events in a net liability position.

Cross-Default Triggers

In addition, a majority of KPCo's non-exchange-traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third-party obligation that is $50 million or greater. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering contractual netting arrangements:

	December 31, 2019	December 31, 2018
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 419	$ 165
Additional Settlement Liability if Cross Default Provision is Triggered	65	4

9. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

The fair values of Long-term Debt are based on quoted market prices, without credit enhancements, for the same or similar issues and the current interest rates offered for instruments with similar maturities classified as Level 2 measurement inputs. These instruments are not marked-to-market. The estimates presented are not necessarily indicative of the amounts that could be realized in a current market exchange.

The book values and fair values of KPCo's Long-term Debt are summarized in the following table:

December 31,			
2019		2018	
Book Value	Fair Value	Book Value	Fair Value
(in thousands)			
$ 870,000	$ 970,437	$ 870,000	$ 903,690

Fair Value Measurements of Financial Assets and Liabilities

For a discussion of fair value accounting and the classification of assets and liabilities within the fair value hierarchy, see the "Fair Value Measurements of Assets and Liabilities" section of Note 1.

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2019

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ —	$ 14,758	$ 7,054	$ (14,909)	$ 6,903
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ —	$ 15,059	$ 1,352	$ (14,930)	$ 1,481

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2018

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 23	$ 10,083	$ 5,867	$ (10,092)	$ 5,881
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 34	$ 10,024	$ 63	$ (9,982)	$ 139

(a) Amounts in "Other" column primarily represent counterparty netting of risk management and hedging contracts and associated cash collateral under the accounting guidance for "Derivatives and Hedging."
(b) Substantially comprised of power contracts.

The following tables set forth a reconciliation of changes in the fair value of net trading derivatives classified as Level 3 in the fair value hierarchy:

Year Ended December 31, 2019	**Derivative Instrument Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2018	$ 5,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	1,282
Settlements	(6,762)
Transfers into Level 3 (c) (d)	(86)
Transfers out of Level 3 (d)	(120)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	5,584
Balance as of December 31, 2019	$ 5,702

Year Ended December 31, 2018	**Derivative Instrument Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2017	$ 1,813
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	6,645
Settlements	(8,312)
Changes in Fair Value Allocated to Regulated Jurisdictions (e)	5,658
Balance as of December 31, 2018	$ 5,804

(a) Included in revenues on KPCo's statements of income.
(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.
(c) Represents existing assets or liabilities that were previously categorized as Level 2.
(d) Transfers are recognized based on their value at the beginning if the period that the transfer occurred.
(e) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2019 and 2018:

Significant Unobservable Inputs
December 31, 2019

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
Energy Contracts	$ 1,049	$ 475	Discounted Cash Flow	Forward Market Price	$ 12.70	$ 41.20	$ 25.92
FTRs	6,005	877	Discounted Cash Flow	Forward Market Price	(0.47)	4.07	1.30
Total	$ 7,054	$ 1,352					

Significant Unobservable Inputs
December 31, 2018

	Fair Value		Valuation	Significant Unobservable	Input/Range		
	Assets	Liabilities	Technique	Input (a)	Low	High	Weighted Average (b)
	(in thousands)						
Energy Contracts	$ 430	$ 63	Discounted Cash Flow	Forward Market Price	$ 16.82	$ 62.65	$ 37.00
FTRs	5,437	—	Discounted Cash Flow	Forward Market Price	0.05	6.21	1.62
Total	$ 5,867	$ 63					

(a) Represents market prices in dollars per MWh.
(b) The weighted average is the product of the forward market price of the underlying commodity and volume weighted by term.

The following table provides the measurement uncertainty of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of December 31, 2019 and 2018:

Uncertainty of Fair Value Measurements

Significant Unobservable Input	Position	Change in Input	Impact on Fair Value Measurement
Forward Market Price	Buy	Increase (Decrease)	Higher (Lower)
Forward Market Price	Sell	Increase (Decrease)	Lower (Higher)

10. INCOME TAXES

Income Tax Expense

The details of KPCo's Income Tax Expense are as follows:

	Years Ended December 31, 2019	2018
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 1,380	$ 2,256
Deferred	202	4,814
Investment Tax Credit	—	(1)
Total	1,582	7,069
Charged (Credited) to Non-Operating Income, Net:		
Current	(634)	(1,715)
Deferred	(927)	645
Total	(1,561)	(1,070)
Total Income Taxes	$ 21	$ 5,999

The following is a reconciliation between the federal income taxes computed by multiplying pretax income by the federal statutory tax rate and the income taxes reported:

	Years Ended December 31, 2019	2018
	(in thousands)	
Net Income	$ 53,300	$ 63,146
Income Tax Expense	21	5,999
Pretax Income	$ 53,321	$ 69,145
Income Taxes on Pretax Income at Statutory Rate (21%)	$ 11,197	$ 14,520
Increase (Decrease) in Income Taxes Resulting from the Following Items:		
Depreciation	1,214	2,600
AFUDC	(258)	(413)
Removal Costs	(1,470)	(1,079)
State and Local Income Taxes, Net	423	884
Tax Reform Excess ADIT Reversal	(10,868)	(10,456)
Other	(217)	(57)
Income Tax Expense	$ 21	$ 5,999
Effective Income Tax Rate	— %	8.7 %

Net Deferred Tax Liability

The following table shows elements of KPCo's net deferred tax liability and significant temporary differences:

	December 31, 2019	December 31, 2018
	(in thousands)	
Deferred Tax Assets	$ 105,810	$ 87,019
Deferred Tax Liabilities	(527,668)	(489,155)
Net Deferred Tax Liabilities	$ (421,858)	$ (402,136)
Property Related Temporary Differences	$ (300,134)	$ (281,168)
Amounts Due to Customers for Future Income Taxes	66,167	53,538
Deferred State Income Taxes	(113,945)	(107,951)
Deferred Income Taxes on Other Comprehensive (Income)/Loss	—	56
Regulatory Assets	(86,590)	(74,806)
All Other, Net	12,644	8,195
Net Deferred Tax Liabilities	$ (421,858)	$ (402,136)

AEP System Tax Allocation Agreement

KPCo joins in the filing of a consolidated federal income tax return with its affiliates in the AEP System. The allocation of the AEP System's current consolidated federal income tax to the AEP System companies allocates the benefit of current tax losses to the AEP System companies giving rise to such losses in determining their current tax expense. The consolidated net operating loss of the AEP System is allocated to each company in the consolidated group with taxable losses. The tax benefit of the Parent is allocated to its subsidiaries with taxable income. With the exception of the allocation of the consolidated AEP System net operating loss and the loss of the Parent and tax credits, the method of allocation reflects a separate return result for each company in the consolidated group.

Federal and State Income Tax Audit Status

KPCo and other AEP and subsidiaries are no longer subject to U.S. federal examination by the IRS for all years through 2015. During the third quarter of 2019, AEP and subsidiaries elected to amend the 2014 and 2015 federal returns and as such the IRS may examine only the amended items on the 2014 and 2015 federal returns.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2007.

Net Income Tax Operating Loss Carryforward

KPCo has Kentucky state net income tax operating loss carryforwards of $137 million and $122 million in 2019 and 2018, respectively. As a result, KPCo recognized deferred state income tax benefits in 2019 and 2018 of $7 million and $6 million, respectively. Management anticipates future taxable income will be sufficient to realize the state net income tax operating loss tax benefits before the state carryforward expires for Kentucky in 2035.

State Tax Legislation

In April 2018, the Kentucky legislature enacted House Bill (H.B.) 487. H.B. 487 adopts mandatory unitary combined reporting for state corporate income tax purposes applicable for taxable years beginning on or after January 1, 2019. H.B. 487 also adopts the 80% federal net operating loss (NOL) limitation under Internal Revenue Code Section 172(a) for NOLs generated after January 1, 2018 and the federal unlimited carryforward period for unused NOLs generated after January 1, 2018. In addition, H.B. 366 was also enacted in April 2018, which among other things, replaces the graduated corporate tax rate structure with a flat 5% tax rate for business income and adopts a single-sales factor apportionment formula for apportioning a corporation's business income to Kentucky. The enacted legislation did not materially impact KPCo's net income.

11. LEASES

KPCo leases property, plant and equipment including, but not limited to, fleet, information technology and real estate leases. These leases require payments of non-lease components, including related property taxes, operating and maintenance costs. As of the adoption date of ASU 2016-02, management elected not to separate non-lease components from associated lease components in accordance with the accounting guidance for "Leases." Many of these leases have purchase or renewal options. Leases not renewed are often replaced by other leases. Options to renew or purchase a lease are included in the measurement of lease assets and liabilities if it is reasonably certain that KPCo will exercise the option.

Lease obligations are measured using the discount rate implicit in the lease when that rate is readily determinable. KPCo has visibility into the rate implicit in the lease when assets are leased from selected financial institutions under master leasing agreements. When the implicit rate is not readily determinable, KPCo measures its lease obligation using its estimated secured incremental borrowing rate. Incremental borrowing rates are comprised of an underlying risk free rate and a secured credit spread relative to the lessee on a matched maturity basis.

Operating and Finance lease rental costs are generally charged to Operation Expenses and Maintenance Expenses in accordance with rate-making treatment for regulated operations. Lease costs associated with capital projects are included in Utility Plant on the balance sheets. For regulated operations with finance leases, a finance lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Finance leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs were as follows:

	Years Ended December 31,	
Lease Rental Costs	**2019**	**2018**
	(in thousands)	
Operating Lease Cost	$ 2,300	$ 2,204
Finance Lease Cost:		
Amortization of Finance Leases	634	845
Interest on Finance Leases	114	107
Total Lease Rental Costs (a)	$ 3,048	$ 3,156

(a) Excludes variable and short-term lease costs, which were immaterial for the twelve months ended December 31, 2019.

Supplemental information related to leases as of and for the twelve months ended December 31, 2019 are shown in the tables below.

Lease Type	Weighted-Average Remaining Lease Term (years):	Weighted-Average Discount Rate
Operating Leases	6.55	3.73%
Finance Leases	5.59	4.42%

Cash Paid for Amounts Included in the Measurement of Lease Liabilities		
		(in thousands)
Operating Cash Flows Used for Operating Leases	$	2,237
Operating Cash Flows Used for Finance Leases		748
Non-cash Acquisitions Under Operating Leases	$	1,829

The following table shows the property, plant and equipment under finance leases, operating leases and related obligations recorded on KPCo's balance sheets.

	December 31, 2019	December 31, 2018
	(in thousands)	
Property, Plant and Equipment Under Finance Leases		
Utility Plant (a)	$ 3,303	$ 2,531
Obligations Under Finance Leases		
Noncurrent	$ 2,576	$ 1,929
Current	727	602
Total Obligations Under Finance Leases	$ 3,303	$ 2,531

(a) Includes $1.8 million and $2.4 million of accumulated provision for depreciation and amortization for the years ended December 31, 2019 and 2018, respectively.

	December 31, 2019
	(in thousands)
Property, Plant and Equipment Under Operating Leases	
Utility Plant (a)	$ 10,127
Obligations Under Operating Leases	
Noncurrent	$ 8,154
Current	2,005
Total Obligations Under Operating Leases	$ 10,159

(a) Includes $1.8 million of accumulated provision for depreciation and amortization.

Future minimum lease payments consisted of the following as of December 31, 2019:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
2020	$ 845	$ 2,401
2021	770	2,154
2022	594	1,759
2023	486	1,460
2024	440	1,105
Later Years	602	2,657
Total Future Minimum Lease Payments	3,737	11,536
Less: Imputed Interest	434	1,377
Estimated Present Value of Future Minimum Lease Payments	$ 3,303	$ 10,159

Future minimum lease payments consisted of the following as of December 31, 2018:

Future Minimum Lease Payments	Finance Leases	Operating Leases
	(in thousands)	
2019	$ 703	$ 2,196
2020	552	2,024
2021	473	1,743
2022	325	1,456
2023	220	1,165
Later Years	649	2,367
Total Future Minimum Lease Payments	2,922	$ 10,951
Less: Imputed Interest	391	
Estimated Present Value of Future Minimum Lease Payments	$ 2,531	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the amount guaranteed. As of December 31, 2019, the maximum potential loss for these lease agreements was $1.7 million assuming the fair value of the equipment is zero at the end of the lease term.

Lessor Activity

KPCo's lessor activity was immaterial as of and for the twelve months ended December 31, 2019.

12. FINANCING ACTIVITIES

Long-term Debt

The following table details long-term debt outstanding:

Type of Debt	Maturity	Weighted-Average Interest Rate as of December 31, 2019	Interest Rate Ranges as of December 31, 2019	Interest Rate Ranges as of December 31, 2018	Outstanding as of December 31, 2019	Outstanding as of December 31, 2018
					(in thousands)	
Senior Unsecured Notes	2021-2047	4.69%	3.13%-8.13%	3.13%-8.13%	$ 730,000	$ 730,000
Pollution Control Bonds (a)	2020	2.00%	2.00%	2.00%	65,000	65,000
Other Long-term Debt	2022	3.18%	3.18%	3.89%	75,000	75,000
Total Long-term Debt					$ 870,000	$ 870,000

(a) KPCo's Pollution Control Bond is subject to redemption earlier than the maturity date.

As of December 31, 2019, outstanding long-term debt was payable as follows:

	2020	2021	2022	2023	2024	After 2024	Total
				(in thousands)			
Principal Amount	$ 65,000	$ 40,000	$ 75,000	$ —	$ 65,000	$ 625,000	$ 870,000
Total Long-term Debt							$ 870,000

Dividend Restrictions

KPCo pays dividends to Parent provided funds are legally available. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of KPCo to transfer funds to Parent in the form of dividends.

All of the dividends declared by KPCo are subject to a Federal Power Act restriction that prohibits the payment of dividends out of capital accounts without regulatory approval; payment of dividends is allowed out of retained earnings only.

KPCo has credit agreements that contain a covenant that limit its debt to capitalization ratio to 67.5%. As of December 31, 2019, KPCo did not exceed its debt to capitalization limit. The method for calculating outstanding debt and capitalization is contractually-defined in the credit agreements.

The most restrictive dividend limitation for KPCo is through the Federal Power Act. As of December 31, 2019, the maximum amount of restricted net assets of KPCo that may not be distributed to Parent in the form of a loan, advance or dividend was $577.4 million.

The Federal Power Act restriction does not limit the ability of KPCo to pay dividends out of retained earnings. The credit agreement covenant restrictions can limit the ability of KPCo to pay dividends out of retained earnings. As of December 31, 2019, there were no restrictions on KPCo's ability to pay dividends out of retained earnings.

Corporate Borrowing Program – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2019 and 2018 are included in Notes Payable to Associated Companies on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits are described in the following table:

Years Ended December 31,	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2019	$ 114,818	$ —	$ 59,492	$ —	$ 113,175	$ 180,000
2018	27,871	13,667	9,077	4,641	27,871	180,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool are summarized in the following table:

Years Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2019	3.43%	1.77%	—%	—%	2.39%	—%
2018	2.97%	1.81%	2.91%	1.82%	2.32%	1.98%

Interest expense and interest income related to the Utility Money Pool are included in Interest on Debt to Associated Companies and Interest and Dividend Income, respectively, on KPCo's statements of income. For amounts borrowed from and advances to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income:

	Years Ended December 31, 2019	2018
	(in thousands)	
Interest Expense	$ 1,470	$ 163
Interest Income	—	2

Securitized Accounts Receivables – AEP Credit

Under a sale of receivables arrangement, KPCo sells, without recourse, certain of its customer accounts receivable and accrued utility revenues balances to AEP Credit and is charged a fee based on AEP Credit's financing costs, administrative costs and uncollectible accounts experience for KPCo's receivables. The costs of customer accounts receivable sold are reported in Other Deductions on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

AEP Credit's receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in July 2021.

KPCo's amounts of accounts receivable and accrued utility revenues under the sale of receivables agreement were $41.6 million and $43.2 million as of December 31, 2019 and 2018, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $3.9 million and $3.8 million for the years ended December 31, 2019 and 2018, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $558.9 million and $591.3 million for the years ended December 31, 2019 and 2018, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "AEP System Tax Allocation Agreement" section of Note 10 in addition to "Corporate Borrowing Program – AEP System" and "Securitized Accounts Receivables – AEP Credit" sections of Note 12.

Power Coordination Agreement

Effective January 1, 2014, the FERC approved the PCA. Under the PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo, PSO, SWEPCo and WPCo. Certain power and natural gas risk management activities for APCo, I&M, KPCo and WPCo are allocated based on the four member companies' respective equity positions.

System Integration Agreement

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity. Margins resulting from trading and marketing activities originating in PJM generally accrue to the benefit of APCo, I&M, KPCo and WPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the equity positions of these companies.

Affiliated Revenues and Purchases

The table below shows the revenues derived from auction sales to affiliates, net transmission agreement sales and other revenues as follows:

Related Party Revenues	Years Ended December 31, 2019	2018
	(in thousands)	
Sales under Interconnection Agreement	$ 285	$ 110
Auction Sales to OPCo (a)	2,069	1,108
Transmission Agreement Sales	13,465	10,183
Other Revenues	1,008	929
Total Affiliated Revenues	$ 16,827	$ 12,330

(a) Refer to the Ohio Auctions section below for further information regarding this amount.

The table below shows the purchased power expenses incurred for purchases from affiliates as follows:

Related Party Purchases	Years Ended December 31, 2019	2018
	(in thousands)	
Direct Purchases from AEGCo (a)	$ 92,084	$ 101,961
Total Affiliated Purchases	$ 92,084	$ 101,961

(a) Refer to the "Unit Power Agreements" section below for further information regarding this amount.

PJM Transmission Service Charges

AEP East Companies are parties to the Transmission Agreement (TA), which defines how transmission costs through PJM OATT are allocated among the AEP East Companies on a 12-month average coincident peak basis. Additional costs for transmission services provided by AEPTCo and other transmission affiliates are billed to KPCo through the PJM OATT.

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2019 and 2018 were $44 million and $24.7 million, respectively, and were recorded in Operation Expenses on KPCo's statements of income.

Ohio Auctions

In connection with OPCo's June 2012 - May 2015 ESP, the PUCO ordered OPCo to conduct energy and capacity auctions for its entire SSO load for delivery beginning in June 2015. Certain affiliated entities, including KPCo, participate in the auction process and have been awarded tranches of OPCo's SSO load. In April 2018, the PUCO issued an order approving the ESP extension stipulation agreement, with no significant changes for the period June 1, 2018 through May 2024. In October 2018, an intervenor filed an appeal with the Ohio Supreme Court challenging various approved riders. In January 2020, the Ohio Supreme Court affirmed the PUCO order, rejecting the filed appeal. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions.

Unit Power Agreements

UPA between AEGCo and I&M

A UPA between AEGCo and I&M (the I&M Power Agreement) provides for the sale by AEGCo to I&M of all the power (and the energy associated therewith) available to AEGCo at the Rockport Plant unless it is sold to another utility. Subsequently, I&M assigns 30% of the power to KPCo. I&M is obligated, whether or not power is available from AEGCo, to pay as a demand charge for the right to receive such power (and as an energy charge for any associated energy taken by I&M) net of amounts received by AEGCo from any other sources, sufficient to enable AEGCo to pay all its operating and other expenses, including a rate of return on the common equity of AEGCo as approved by the FERC. The I&M Power Agreement will continue in effect until the expiration of the lease term of Unit 2 of the Rockport Plant unless extended in specified circumstances.

UPA between AEGCo and KPCo

Pursuant to an assignment between I&M and KPCo and a UPA between AEGCo and KPCo, AEGCo sells KPCo 30% of the power (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo pays to AEGCo in consideration for the right to receive such power the same amounts which I&M would have paid AEGCo under the terms of the I&M Power Agreement for such entitlement. Refer to the Affiliated Revenues and Purchases section above for amounts related to these transactions. The KPCo UPA ends in December 2022.

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_X emissions at certain generation plants in the AEP System. KPCo recorded expenses of $4.8 million and $4.2 million in 2019 and 2018, respectively, for urea transloading provided by I&M. These expenses were recorded as Operation Expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet and then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.4 million and $1.7 million for the years ended December 31, 2019 and 2018, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The table below shows the sales and purchases, recorded in Utility Plant on the balance sheets at net book value:

	Years Ended December 31,	
	2019	2018
	(in thousands)	
Sales	$ 1,304	$ 472
Purchases	90	265

Charitable Contributions to AEP Foundation

The American Electric Power Foundation is funded by American Electric Power and its utility operating units. The Foundation provides a permanent, ongoing resource for charitable initiatives and multi-year commitments in the communities served by AEP and initiatives outside of AEP's 11-state service area. In 2019, KPCo contributed $2.5 million to the AEP Foundation which was recorded in Donations on the statements of income.

Intercompany Billings

KPCo performs certain utility services for other AEP subsidiaries when necessary or practical. The costs of these services are billed on a direct-charge basis, whenever possible, or on reasonable basis of proration for services that benefit multiple companies. The billings for services are made at cost and include no compensation for the use of equity capital.

AEPSC

AEPSC provides certain managerial and professional services to AEP's subsidiaries. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. AEPSC and its billings are subject to regulation by the FERC. KPCo's total billings from AEPSC for the years ended December 31, 2019 and 2018 were $77 million and $71.2 million, respectively.

14. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Utility Plant on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides total regulated annual composite depreciation rates and depreciable lives for KPCo. Nonregulated depreciation rate ranges and depreciable life ranges are not applicable or not meaningful for 2019 and 2018.

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2019	3.0	2.6	3.4	9.5
2018	3.1	2.7	3.4	9.6

The composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to accumulated depreciation on the balance sheets. Actual removal costs incurred are charged to accumulated depreciation.

Asset Retirement Obligations (ARO)

KPCo records ARO in accordance with the accounting guidance for “Asset Retirement and Environmental Obligations” for the retirement of ash disposal facilities and asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property’s use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2019 and 2018 aggregate carrying amounts of ARO for KPCo:

Year	ARO as of January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled (a)	Revisions in Cash Flow Estimates (a)	ARO as of December 31,
			(in thousands)			
2019	$ 41,681	$ 2,405	$ —	$ (23,564)	$ 23,066	$ 43,588
2018	51,238	2,084	—	(31,501)	19,860	41,681

(a) Primarily related to ash pond closure and asbestos abatement.

Jointly-owned Electric Facilities

KPCo, jointly with WPCo, owns Unit 1 and Unit 2 of the Mitchell Generating Station. KPCo and WPCo each have a 50% ownership of Unit 1 and Unit 2 of the Mitchell Generating Station. Using its own financing, each participating company is obligated to pay its share of the costs in the same proportion as its ownership interest. KPCo's proportionate share of the operating costs associated with this facility is included in its statements of income and the investment and accumulated depreciation are reflected in its balance sheets under Utility Plant as follows:

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2019					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0%	$ 1,047,407	$ 4,978	$ 443,277
KPCo's Share as of December 31, 2018					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0%	$ 1,024,359	$ 16,101	$ 418,989

(a) Operated by KPCo.

15. REVENUE FROM CONTRACTS WITH CUSTOMERS

Disaggregated Revenues from Contracts with Customers

The table below represents KPCo's revenues from contracts with customers, net of respective provisions for refund, by type of revenue:

	Years Ended December 31, 2019	Years Ended December 31, 2018
	(in thousands)	
Retail Revenues:		
Residential Revenues	$ 246,959	$ 261,184
Commercial Revenues	151,334	157,578
Industrial Revenues	151,595	159,560
Other Retail Revenues	1,980	1,971
Total Retail Revenues	551,868	580,293
Wholesale Revenues:		
Generation Revenues (a)	35,859	40,994
Transmission Revenues (b)	19,400	20,839
Total Wholesale Revenues	55,259	61,833
Other Revenues from Contracts with Customers (a)	14,733	16,153
Total Revenues from Contracts with Customers	621,860	658,279
Other Revenues:		
Alternative Revenues (a)	4,527	(6,142)
Total Other Revenues	4,527	(6,142)
Total Operating Revenues	$ 626,387	$ 652,137

(a) Amounts included affiliated and nonaffiliated revenues.
(b) Amounts included affiliated and nonaffiliated revenues. The affiliated revenue were $9.1 million and $15 million for years ended December 31, 2019 and 2018, respectively.

Performance Obligations

KPCo has performance obligations as part of its normal course of business. A performance obligation is a promise to transfer a distinct good or service, or a series of distinct goods or services that are substantially the same and have the same pattern of transfer to a customer. The invoice practical expedient within the accounting guidance for "Revenue from Contracts with Customers" allows for the recognition of revenue from performance obligations in the amount of consideration to which there is a right to invoice the customer and when the amount for which there is a right to invoice corresponds directly to the value transferred to the customer.

The purpose of the invoice practical expedient is to depict an entity's measure of progress toward completion of the performance obligation within a contract and can only be applied to performance obligations that are satisfied over time and when the invoice is representative of services provided to date. KPCo elected to apply the invoice practical expedient to recognize revenue for performance obligations satisfied over time as the invoices from the respective revenue streams are representative of services or goods provided to date to the customer. Performance obligations for KPCo are summarized as follows:

Retail Revenues

KPCo has performance obligations to generate, transmit and distribute electricity for sale to rate-regulated retail customers. The performance obligation to deliver electricity is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Revenues are variable as they are subject to the customer's usage requirements.

Rate-regulated retail customers typically have the right to discontinue receiving service at will, therefore these contracts between KPCo and their customers for rate-regulated services are generally limited to the services requested and received to date for such arrangements. Retail customers are generally billed on a monthly basis, and payment is typically due within 15 to 20 days after the issuance of the invoice.

Wholesale Revenues - Generation

KPCo has performance obligations to sell electricity to wholesale customers from generation assets in PJM. The performance obligation to deliver electricity from generation assets is satisfied over time as the customer simultaneously receives and consumes the benefits provided. Wholesale generation revenues are variable as they are subject to the customer's usage requirements.

KPCo also has performance obligations to stand ready in order to promote grid reliability. Stand ready services are sold into PJM's Reliability Pricing Model (RPM) capacity market. RPM entails a base auction and at least three incremental auctions for a specific PJM delivery year, with the incremental auctions spanning three years. The performance obligation to stand ready is satisfied over time and the consideration for which is variable until the occurrence of the final incremental auction, at which point the performance obligation becomes fixed.

Payments from the RTO for stand ready services are typically received within one week from the issuance of the invoice, which is typically issued weekly. Gross margin resulting from generation sales are primarily subject to margin sharing agreements with customers, where the revenues are reflected gross in the disaggregated revenues table above.

Wholesale Revenues - Transmission

KPCo has performance obligations to transmit electricity to wholesale customers through assets owned and operated by KPCo and other AEP subsidiaries. The performance obligation to provide transmission services in PJM encompass a time frame greater than a year, where the performance obligation within PJM is partially fixed for a period of one year or less. Payments from the RTO for transmission services are typically received within one week from the issuance of the invoice, which is issued weekly for PJM.

KPCo collects revenues through Transmission Formula Rates. The FERC-approved rates establish the annual transmission revenue requirement (ATRR) and transmission service rates for transmission owners. The formula rates establish rates for a one year period and also include a true-up calculation for the prior year's billings, allowing for over/under-recovery of the transmission owner's ATRR. The annual true-ups meet the definition of alternative revenues in accordance with the accounting guidance for "Regulated Operations," and are therefore presented as such in the disaggregated revenues table above.

AEP East Companies are parties to the Transmission Agreement (TA), which defines how transmission costs are allocated among the AEP East Companies on a 12-month average coincident peak basis. AEPTCo is a load serving entity within PJM providing transmission services to affiliates in accordance with the OATT and TA. Affiliate revenues as a result of the TA are reflected as Transmission Revenues in the disaggregated revenues table above.

Fixed Performance Obligations

The following table represents KPCo's remaining fixed performance obligations satisfied over time as of December 31, 2019. Fixed performance obligations primarily include wholesale transmission services, electricity sales for fixed amounts of energy and stand ready services into PJM's RPM market. The amounts shown in the table below include affiliated and nonaffiliated revenues.

2020	2021-2022	2023-2024	After 2024	Total
		(in thousands)		
$ 24,263	$ 2,870	$ 2,870	$ 1,435	$ 31,438

Contract Assets and Liabilities

Contract assets are recognized when KPCo has a right to consideration that is conditional upon the occurrence of an event other than the passage of time, such as future performance under a contract. KPCo did not have material contract assets as of December 31, 2019.

When KPCo receives consideration, or such consideration is unconditionally due from a customer prior to transferring goods or services to the customer under the terms of a sales contract, they recognize a contract liability on the balance sheet in the amount of that consideration. Revenue for such consideration is subsequently recognized in the period or periods in which the remaining performance obligations in the contract are satisfied. KPCo's contract liabilities typically arise from advanced payments of services provided primarily with respect to joint use agreements for utility poles. KPCo did not have material contract liabilities as of December 31, 2019.

Accounts Receivable from Contracts with Customers

Accounts receivable from contracts with customers are presented on KPCo's balance sheets in Customer Accounts Receivable. KPCo's balances for receivables from contracts that are not recognized in accordance with the accounting guidance for "Revenue from Contracts with Customers" included in Customer Accounts Receivable were not material as of December 31, 2019. See "Securitized Accounts Receivable - AEP Credit" section of Note 12 for additional information.

The amount of affiliated accounts receivable from contracts with customers included in Accounts Receivable from Associated Companies on KPCo's balance sheets were $7 million and $8.4 million, respectively, as of December 31, 2019 and 2018.

Contract Costs

Contract costs to obtain or fulfill a contract are accounted for under the guidance for "Other Assets and Deferred Costs" and presented as a single asset and neither bifurcated nor reclassified between current assets and deferred debits on KPCo's balance sheets. Contract costs to acquire a contract are amortized in a manner consistent with the transfer of goods or services to the customer in Operation Expenses on KPCo's statements of income. KPCo did not have material contract costs as of December 31, 2019 and 2018.

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year				261,112
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(473,100)
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				(473,100)
5	Balance of Account 219 at End of Preceding Quarter/Year				(211,988)
6	Balance of Account 219 at Beginning of Current Year				211,988
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(1,001,711)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(1,001,711)
10	Balance of Account 219 at End of Current Quarter/Year				(789,723)

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			261,112	[redacted]	[redacted]
2			(473,100)	[redacted]	[redacted]
3				[redacted]	[redacted]
4			(473,100)	63,145,732	62,672,632
5			(211,988)	[redacted]	[redacted]
6			211,988	[redacted]	[redacted]
7			(1,001,711)	[redacted]	[redacted]
8				[redacted]	[redacted]
9			(1,001,711)	53,299,747	52,298,036
10			(789,723)	[redacted]	[redacted]

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,739,638,353	2,739,638,353
4	Property Under Capital Leases	13,430,460	13,430,460
5	Plant Purchased or Sold		
6	Completed Construction not Classified	126,603,498	126,603,498
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,879,672,311	2,879,672,311
9	Leased to Others		
10	Held for Future Use	556,145	556,145
11	Construction Work in Progress	98,671,345	98,671,345
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	2,978,899,801	2,978,899,801
14	Accum Prov for Depr, Amort, & Depl	1,026,166,192	1,026,166,192
15	Net Utility Plant (13 less 14)	1,952,733,609	1,952,733,609
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,006,542,436	1,006,542,436
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	19,623,756	19,623,756
22	Total In Service (18 thru 21)	1,026,166,192	1,026,166,192
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,026,166,192	1,026,166,192

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
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Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	52,919	
4	(303) Miscellaneous Intangible Plant	37,284,235	13,364,729
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	37,337,154	13,364,729
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	4,838,789	
9	(311) Structures and Improvements	70,387,839	1,944,518
10	(312) Boiler Plant Equipment	946,830,398	23,480,887
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	117,348,458	1,441,939
13	(315) Accessory Electric Equipment	30,315,653	1,086,216
14	(316) Misc. Power Plant Equipment	12,466,101	823,717
15	(317) Asset Retirement Costs for Steam Production	11,564,584	1,638,708
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,193,751,822	30,415,985
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power PLant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)		
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products, and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc. Power Plant Equipment		
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)		
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,193,751,822	30,415,985

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	35,913,228	787,287
49	(352) Structures and Improvements	6,928,518	1,756,661
50	(353) Station Equipment	205,565,024	17,046,510
51	(354) Towers and Fixtures	100,225,640	117,714
52	(355) Poles and Fixtures	114,611,524	20,521,347
53	(356) Overhead Conductors and Devices	139,956,330	8,613,340
54	(357) Underground Conduit	11,590	315,401
55	(358) Underground Conductors and Devices	106,066	273,870
56	(359) Roads and Trails		
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	603,317,920	49,432,130
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,722,764	139,557
61	(361) Structures and Improvements	5,211,109	1,540,780
62	(362) Station Equipment	111,487,301	15,917,346
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	212,857,750	11,656,391
65	(365) Overhead Conductors and Devices	240,818,344	21,749,287
66	(366) Underground Conduit	7,350,554	169,558
67	(367) Underground Conductors and Devices	11,585,613	171,365
68	(368) Line Transformers	136,901,058	6,946,660
69	(369) Services	62,980,038	3,091,692
70	(370) Meters	25,075,538	672,185
71	(371) Installations on Customer Premises	19,126,093	1,404,813
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,148,442	282,457
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	845,264,604	63,742,091
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	1,543,991	
87	(390) Structures and Improvements	23,367,410	1,947,904
88	(391) Office Furniture and Equipment	2,051,277	373,809
89	(392) Transportation Equipment	14,768	
90	(393) Stores Equipment	262,364	19,396
91	(394) Tools, Shop and Garage Equipment	5,299,121	334,508
92	(395) Laboratory Equipment	261,453	
93	(396) Power Operated Equipment	5,931	
94	(397) Communication Equipment	14,764,796	1,549,896
95	(398) Miscellaneous Equipment	1,800,882	3,982
96	SUBTOTAL (Enter Total of lines 86 thru 95)	49,371,993	4,229,495
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	81,055	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	49,453,048	4,229,495
100	TOTAL (Accounts 101 and 106)	2,729,124,548	161,184,430
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,729,124,548	161,184,430

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			52,919		3
3,605,147			47,043,817		4
3,605,147			47,096,736		5
					6
					7
			4,838,789		8
293,177			72,039,180		9
4,719,140			965,592,145		10
					11
815,963			117,974,434		12
296,675			31,105,194		13
33,826			13,255,992		14
			13,203,292		15
6,158,781			1,218,009,026		16
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6,158,781			1,218,009,026		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
		207,545	36,908,060		48
31,828			8,653,351		49
623,498			221,988,036		50
287,714			100,055,640		51
446,685		-207,545	134,478,641		52
269,390			148,300,280		53
			326,991		54
			379,936		55
					56
					57
1,659,115			651,090,935		58
					59
			7,862,321		60
55,517			6,696,372		61
1,559,127			125,845,520		62
					63
2,093,613			222,420,528		64
3,377,971			259,189,660		65
2,047			7,518,065		66
18,627			11,738,351		67
2,370,668			141,477,050		68
452,167			65,619,563		69
457,404			25,290,319		70
1,813,361			18,717,545		71
					72
115,349			4,315,550		73
					74
12,315,851			896,690,844		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			1,543,991		86
262,369			25,052,945		87
			2,425,086		88
			14,768		89
			281,760		90
			5,633,629		91
			261,453		92
			5,931		93
65,864			16,248,828		94
			1,804,864		95
328,233			53,273,255		96
					97
			81,055		98
328,233			53,354,310		99
24,067,127			2,866,241,851		100
					101
					102
					103
24,067,127			2,866,241,851		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
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44					
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46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Ramey Substation (4205)	10/1/09	2023	556,145
3				
4				
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6				
7				
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11				
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21	Other Property:			
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46				
47	Total			556,145

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BS Repurpose BAP	6,410,872
2	KYPCo Distr Pre Eng Parent	2,262,789
3	Corp Prgrm Billing - KP Distri	1,219,443
4	Corp Prgrm Billing - KYPCO Gen	1,193,125
5	KY Next Generation Radio Sys	5,686,958
6	KY D 2017-00179	2,952,531
7	T/KP/NERC Physical Security	4,278,299
8	T/KP/TranscoAssetRenewl&Refurb	1,983,714
9	Johns Creek Station Rehab	3,008,250
10	Leslie Station Rehab	1,696,900
11	Hazard Station Rehab	1,965,118
12	D/KP/Capital Blanket - KYPCo	1,119,827
13	T/KP/Capital Blanket - KYPCo	4,386,035
14	T/KP/Transmisison Work	1,480,819
15	T/KY/KY Transmisison Work	2,146,792
16	T/KP/Transmission Work	13,586,868
17	KPCo-D Baseline Work	3,156,852
18	KPCo T Work	1,000,298
19	KYPCo Trans Pre Eng Parent	1,646,800
20	ROW Capital widening & removal	11,096,863
21	WS-CI-KEPCo-G PPB	5,054,406
22	Ed-Ci-Kepco-D Ast Imp	6,209,301
23	SS-CI-KEPCo-D GEN PLT	2,498,714
24	Other Minor Projects Which is under 5% or $1,000,000	12,629,771
25		
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43	TOTAL	98,671,345

Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	951,795,075	951,795,075		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	85,177,886	85,177,886		
4	(403.1) Depreciation Expense for Asset Retirement Costs	223,101	223,101		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-80,028	-80,028		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	85,320,959	85,320,959		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	20,461,980	20,461,980		
13	Cost of Removal	12,476,289	12,476,289		
14	Salvage (Credit)	2,613,144	2,613,144		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	30,325,125	30,325,125		
16	Other Debit or Cr. Items (Describe, details in footnote):	-248,473	-248,473		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,006,542,436	1,006,542,436		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	494,846,967	494,846,967		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	224,777,570	224,777,570		
26	Distribution	268,613,000	268,613,000		
27	Regional Transmission and Market Operation				
28	General	18,304,899	18,304,899		
29	TOTAL (Enter Total of lines 20 thru 28)	1,006,542,436	1,006,542,436		

Schedule Page: 219 Line No.: 8 Column: c

Big Sandy Ash Pond deferred depreciation expense (ref: Case No. 2012-00578)	$	210,958
Environmental costs recovered per KPSC Order (ref: Case No. 2014-00396)		(296,618)
Asbestos ARO depreciation expense in account 1080013		5,632
Total		$(80,028)

Schedule Page: 219 Line No.: 13 Column: c

Includes $4,042,824 of removal cost in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 14 Column: c

Includes ($1,615,415)of salvage in retirement work in progress (RWIP).

Schedule Page: 219 Line No.: 16 Column: c

Asbestos ARO reserve in account 1080013. ($248,473)

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
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42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
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Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	10,227,377	28,444,250	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	393,217	1,410,788	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	5,831,138	8,146,800	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	10,829,254	9,375,656	Electric
8	Transmission Plant (Estimated)	17,108	11,981	Electric
9	Distribution Plant (Estimated)	199,815	158,945	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	16,505	21,659	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	16,893,820	17,715,041	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	27,514,414	47,570,079	

Schedule Page: 227   Line No.: 11   Column: c

Assigned to - Other includes customer account, administrative and general expenses.

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	216,233.00	8,868,691	54,079.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	618.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	6,650.00	176,727		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Restricted Title IV SO2 s				
23	Surrenders				
24	Unknown				
25	Consent Decree Surrenders	-57.00	-3,250		
26	Other				
27					
28	Total	-57.00	-3,250		
29	Balance-End of Year	210,258.00	8,695,214	54,079.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	362.00		362.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	362.00			
40	Balance-End of Year			362.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		39		
45	Gains		39		
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
59,343.00		59,342.00		1,388,672.00		1,777,669.00	8,868,691	1
								2
								3
4,653.00		4,653.00		64,187.00		74,111.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						6,650.00	176,727	18
								19
								20
								21
								22
								23
								24
						-57.00	-3,250	25
								26
								27
						-57.00	-3,250	28
63,996.00		63,995.00		1,452,859.00		1,845,187.00	8,695,214	29
								30
								31
								32
								33
								34
								35
362.00		362.00		24,244.00		25,692.00		36
				723.00		723.00		37
								38
				361.00		723.00		39
362.00		362.00		24,606.00		25,692.00		40
								41
								42
								43
							39	44
							39	45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	19,363.00		2,359.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	246.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	4,561.00			
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Element Markets EmissionC	410.00			
23	Fathom Energy LLC	325.00			
24	Koch Supply & Trading, LP	250.00			
25	Dynegy Marketing and TraC	200.00			
26	Midland Cogeneration Vene	150.00			
27	Other	60.00			
28	Total	1,395.00			
29	Balance-End of Year	13,653.00		2,359.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		188,060		
34	Gains		188,060		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
3,786.00		3,786.00				29,294.00		1
								2
								3
5,324.00		4,566.00		6,735.00		16,871.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						4,561.00		18
								19
								20
								21
						410.00		22
						325.00		23
						250.00		24
						200.00		25
						150.00		26
						60.00		27
						1,395.00		28
9,110.00		8,352.00		6,735.00		40,209.00		29
								30
								31
								32
							188,060	33
							188,060	34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM - #AD2-105	2,375	186	(2,294)	186
3	PJM - #AD2-106	8,154	186	(8,076)	186
4	PJM - #AD2-107	5,148	186	(5,084)	186
5	PJM - #AE2-208	2,558	186	(2,447)	186
6	PJM AC1-101 & 102	19,842	186		
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23	Big Sandy	521	500	8,066	500
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Deferred Storm Expenses	8,366,230		593	2,066,559	6,299,671
2	Kentucky PSC Case No. 2017-00179					
3	Amortz period: January 2018 - December 2023					
4						
5	SFAS 109 Deferred FIT	36,935,499	13,402,249	282/283	12,752,035	37,585,713
6						
7	SFAS 109 Deferred SIT	104,847,035	20,405,985	282/283	13,991,679	111,261,341
8						
9	Post In-Service AFUDC Hanging Rock/	465,192		406	33,408	431,784
10	Jefferson 765 KV Line					
11	Amortz period: Dec 1984 - Nov 2032					
12						
13	Depreciation Expense - Hanging Rock/	72,481		406	5,208	67,273
14	Jefferson 765 KV Line					
15	Amortz period: Dec 1984 - Nov 2032					
16						
17	RTO Deferred Equity Carrying Charge	(12,588)	12,588			
18						
19	BridgeCo Transmission Org Funding	44,332		407	44,332	
20	Amortz period: Jan 2005 - Dec 2019					
21	FERC Docket AC04-101-000					
22						
23	Other PJM Integration	46,836		407	46,836	
24	Amortz period: Jan 2005 - Dec 2019					
25	FERC Docket AC04-101-000					
26						
27	Carrying Charges - RTO Startup Costs	29,311		407	29,311	
28	Amortz period: Jan 2005 - Dec 2019					
29	FERC Docket AC04-101-000					
30						
31	Alliance RTO Deferred Expense	23,202		407	23,202	
32	Amortz period: Jan 2005 - Dec 2019					
33	FERC Docket AC04-101-000					
34						
35	SFAS 112 Post Employment Benefit	2,809,366	1,619,279	926	1,259,440	3,169,205
36						
37	SFAS 158 Employers' Accounting for Defined	46,613,491	2,201,311	Footnote	5,082,940	43,731,862
38	Benefit Pension and Other Postretirement Plans					
39						
40	Unrealized Loss on Forward Commitments	155,170	1,873,959	Footnote	167,235	1,861,894
41						
42						
43						
44	TOTAL	535,438,073	118,297,905		83,702,181	570,033,797

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Netting of Trading Activities related to		2,523,299	254	3,948,420	-1,425,121
2	Unrealized Gains/Losses on Forward Commitments					
3	between Regulated Assets/Liabilities					
4						
5	SFAS 106 Medicare Subsidy	1,299,720		926	216,620	1,083,100
6	Amortz period: Jan 2013 - Dec 2024					
7						
8	Under Recovery of PJM True-Up	32,115	290,229	447	300,632	21,712
9	Amortz period: Jan 2018 - Dec 2018					
10						
11	Cost of Removal-Big Sandy Coal	(32,667,030)	3,688,602	108	90,298	-29,068,726
12	Kentucky PSC Case No. 2014-00396					
13						
14	NBV - AROs Retired Plants	28,706,829	23,035,732	182	23,027,357	28,715,204
15	Kentucky PSC Case No. 2014-00396					
16						
17	M&S - Retiring Plants	3,015,785				3,015,785
18	Kentucky PSC Case No. 2014-00396					
19						
20	Unrecovered Plant - Big Sandy	256,546,288		146	37,226	256,509,062
21	Kentucky PSC Case No. 2014-00396					
22						
23	IGCC Pre-Construction Costs	1,144,878		506	53,250	1,091,628
24	Kentucky PSC Case No. 2014-00396					
25						
26	CCS FEED Study Costs	750,658		506	34,914	715,744
27	Kentucky PSC Case No. 2014-00396					
28						
29	Spent AROs - Big Sandy Coal	64,331,858	23,027,357			87,359,215
30	Kentucky PSC Case No. 2014-00396					
31						
32	Big Sandy Recovery Over/Under	(13,755,875)	16	407	6,463,497	-20,219,356
33	Kentucky PSC Case No. 2014-00396					
34						
35	Big Sandy Retirement Rider Unit 2 O&M	917,491	199,713	512	11,802	1,105,402
36	Kentucky PSC Case No. 2014-00396					
37						
38	Unrecovered Purchased Power-PPA					
39	Kentucky PSC Case No. 2014-00396					
40						
41	Deferred Depreciation - Environmental	4,644,238	4,673,258	403	4,969,876	4,347,620
42	Kentucky PSC Case No. 2014-00396					
43	Kentucky PSC Case No. 2014-00396					
44	TOTAL	535,438,073	118,297,905		83,702,181	570,033,797

Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter/Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	BS1OR Under Recovery	1,083,437				1,083,437
3	Kentucky PSC Case No. 2014-00396					
4						
5	Unrecovered Fuel Cost	2,379,150	3,341,003	501	5,720,153	
6						
7	NERC Compliance and Cybersecurity Costs	114,758	211,268	404, 431	38,022	288,004
8	Kentucky PSC Case No. 2014-00396					
9						
10	Capacity Charge Tariff					
11	Kentucky PSC Case No. 2014-00396, TFS 2016-00430		116,532	Footnote	28,264	88,268
12						
13	Rate Cases Expenses	938,844		928	458,333	480,511
14	Kentucky PSC Case No. 2017-00179					
15	Amortz period: Jan 2018 - Jan 2021					
16						
17	OSS Margin Sharing	1,082,688	1,090,428	Footnote	2,173,116	
18	Kentucky PSC Case No. 2017-00179					
19						
20	Rockport Capacity Deferral	14,476,684	16,316,580	431	628,216	30,165,048
21	Kentucky PSC Case No. 2017-00179					
22						
23	GreenHat Default Contingency		268,517			268,517
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	535,438,073	118,297,905		83,702,181	570,033,797

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175, 182, 244, 456

Schedule Page: 232.2 Line No.: 11 Column: d

440, 442, 444

Schedule Page: 232.2 Line No.: 17 Column: d

440,442,444

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Deferred Property Tax	20,664,409	20,783,781	408	21,042,687	20,405,503
2						
3	Agency Fees - Factored A/R	863,409	11,484,874	142/184	11,515,722	832,561
4						
5	Unamortized Credit Line Fees	299,748	6,116	431	132,020	173,844
6	Amortized thru June 2021					
7						
8	Deferred Lease Assets	60,337	293,220	143/184	219,700	133,857
9						
10	Estimated Barging Bills	900,952	20,808,472	151/154	21,709,424	
11						
12	Miscellaneous Items	4,117	169,071	Footnote	171,272	1,916
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
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32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress	144,915				546,358
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	22,937,887				22,094,039

Schedule Page: 233 Line No.: 12 Column: d

253/565/588

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Provision Revenue Refunds	95,502	94,890
3	Accrued BK ARO Cost	7,280,077	9,165,188
4	Int Exp Capd for Tax	5,036,287	5,315,925
5	Accrued Book Pension	-9,154,527	-8,949,061
6	NOL State Deferred Tax Asset	6,108,412	6,856,608
7	Other	1,953,852	2,989,110
8	TOTAL Electric (Enter Total of lines 2 thru 7)	11,319,603	15,472,660
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	75,699,625	90,337,457
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	87,019,228	105,810,117

Notes

Page 234 Line 17	Beginning of Year	End of Year
Non Utility -Acct 190.2	89,591	1,019,359
SFAS 109-Regulatory Assets	75,553,683	89,528,020
Acc Def Income Taxes	56,351	
Accu def income taxes Pension-OCT		(209,923)
	75,699,625	90,337,456

Reconciliation of details applicable to Account 190, Line 18, Columns [b] & [c]

Balance at Beginning of Year:	87,019,228
(Less) Amounts Debited to Account 410.1	(13,237,275)
(Less) Amounts Debited to Account 410.2	(974,391)
(Plus) Amounts Credited to Account 411.1	13,118,614
(Plus) Amounts Credited to Account 411.2	1,904,158
(Less) Amounts Debited to Various Account	(72,439,490)
(Plus) Amounts Credit to Various Account	90,419,273
Balance at End of Year:	105,810,117

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	2,000,000	50.00	
2				
3	Total Common Stock	2,000,000		
4				
5				
6	Preferred Stock: None			
7				
8	Total Preferred Stock			
9				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,009,000	50,450,000					1
						2
1,009,000	50,450,000					3
						4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received From Stockholders	
2	Contributions by Parent Company prior to 2017	523,324,094
3		
4		
5		
6	Subtotal - Account 208	523,324,094
7		
8	Account 209 - Reduction in Par or Stated Value of Capital Stock	
9		
10	Account 210 - Gain on Resale/Cancellation of Reacquired Capital Stock	
11		
12	Account 211 - Miscellaneous Paid-In-Capital	2,811,185
13		
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40	TOTAL	526,135,279

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Item incorrectly recorded to this account. Corrected in 2020	236
2		
3		
4		
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21		
22	TOTAL	236

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221 - BONDS		
2	SUBTOTAL ACCOUNT 221 - BONDS		
3			
4	ACCOUNT 222 - REQUIRED BONDS		
5	SUBTOTAL ACCOUNT 222 - REQUIRED BONDS		
6			
7	ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES		
8	SUBTOTAL ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES		
9			
10	ACCOUNT 224 - OTHER LONG-TERM DEBT		
11	Senior Unsecured Notes - 5.625%, Series D	75,000,000	736,575
12			
13	Senior Unsecured Notes - 7.250%, State Commission Authority Case # 2008-00442	40,000,000	218,073
14			
15	Senior Unsecured Notes - 8.030%, State Commission Authority Case # 2008-00442	30,000,000	148,147
16			
17	Senior Unsecured Notes - 8.130%, State Commission Authority Case # 2008-00442	60,000,000	343,016
18			
19	Senior Unsecured Notes - 4.180%, Series A	120,000,000	638,464
20	State Commission Authority Case# 2014-00210		
21			
22	Senior Unsecured Notes - 4.33%, Series B	80,000,000	414,941
23	State Commission Authority Case# 2014-00210		
24			
25	West Virginia Economic Development Authority Mitchell Project Series 2014A	65,000,000	675,501
26	State Commission Authority Case# 2013-00410		146,250
27			
28	Local Bank Term Loan, State Commission Authority Case# 2014-00210	75,000,000	509,274
29			502,493
30			
31	Private Placement Senior Unsecured Notes - 3.13%, Series F	65,000,000	210,764
32	State Commission Authority: Case No. 2016-00345		
33	TOTAL	870,000,000	5,386,555

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	Private Placement Senior Unsecured Notes - 3.35%, Series G	40,000,000	129,701
3	State Commission Authority: Case No. 2016-00345		
4			
5	Private Placement Senior Unsecured Notes - 3.45%, Series H	165,000,000	535,017
6	State Commission Authority: Case No. 2016-00345		
7			
8	Private Placement Senior Unsecured Notes - 4.12%, Series I	55,000,000	178,339
9	State Commission Authority: Case No. 2016-00345		
10			
11	SUBTOTAL ACCOUNT 224 - OTHER LONG-TERM DEBT	870,000,000	5,386,555
12			
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29			
30			
31			
32			
33	TOTAL	870,000,000	5,386,555

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750	11
						12
06/18/2009	06/18/2021	06/18/2009	06/18/2021	40,000,000	2,900,000	13
						14
06/18/2009	06/18/2029	06/18/2009	06/18/2029	30,000,000	2,409,000	15
						16
06/18/2009	06/18/2039	06/18/2009	06/18/2039	60,000,000	4,878,000	17
						18
9/30/2014	9/30/2026	9/30/2014	9/30/2026	120,000,000	5,016,000	19
						20
						21
12/30/2014	12/30/2026	12/30/2014	12/30/2026	80,000,000	3,464,000	22
						23
						24
6/26/2014	4/1/2036	6/26/2014	6/26/2017	65,000,000	1,298,344	25
		6/19/2017	6/19/2020			26
						27
11/5/2014	11/5/2018	11/5/2014	11/5/2018	75,000,000	2,820,198	28
10/26/2018	10/26/22	10/26/18	10/26/22			29
						30
09/12/2017	09/12/2024	09/12/2017	09/12/2024	65,000,000	2,034,500	31
						32
				870,000,000	38,337,292	33

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
09/12/2017	09/12/2027	09/12/2017	09/12/2027	40,000,000	1,340,000	2
						3
						4
09/12/2017	09/12/2029	09/12/2017	09/12/2029	165,000,000	5,692,500	5
						6
						7
09/12/2017	09/12/2047	09/12/2017	09/12/2047	55,000,000	2,266,000	8
						9
						10
				870,000,000	38,337,292	11
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						31
						32
				870,000,000	38,337,292	33

Schedule Page: 256 Line No.: 25 Column: a

Issuance: West Virginia Economic Development Authority, Mitchell Project Series 2014A
Principal Amount: $65,000,000
Date of Issuance: 06/26/2014
Date of Maturity: 04/01/2036
Puttable Date: Bonds were subject to mandatory tender for purchase on 06/26/2017. Issuance expense of 675,501 was fully amortized as of 06/19/2017.

These bonds were re-marketed 06/19/2017:
Issuance: West Virginia Economic Development Authority, Mitchell Project Series 2014A
Principal Amount: $65,000,000
Date of Issuance: 06/19/2017
Date of Maturity: 04/01/2036
Puttable Date: Bonds are subject to mandatory tender for purchase on 6/19/2020. Issuance expense of 146,250 to be amortized through 06/19/2020.

Schedule Page: 256 Line No.: 28 Column: a

The $75 million multiple draw term loan was issued on November 5, 2014. The interest rate is variable and the maturity date is November 5, 2018. Note was reissued October 26, 2018 with a new maturity date of 10/26/2022.

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	53,299,746
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-8,543,052
28	Show Computation of Tax:	
29		
30		
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44		

Schedule Page: 261   Line No.: 28   Column: b

FOOTNOTE DATA

Schedule Page: 261 Line No.: 28 Column: b	in $ 000's
Net Income for the Year per Page 117	53,300
Federal Income Taxes	(518)
State Income Taxes	539
Pre-Tax Book Income	53,321
Excess Tax vs Book Depreciation	21,225
AFUDC and Other Capitalization Differences	(797)
Book Unit of Property Adjustment	(46,239)
Removal Cost	(14,931)
Pollution Control Equipment	7,610
Property Tax	NIL
Provision for Revenue Refunds	(199)
Deferred Fuel	2,379
Self Insurance / Worker's Comp	(400)
Accrued Book Pension Expense	806
Deferred Storm Damage	2,067
Misc Book Accruals, Reserves & Deferrals	(30,151)
Non Deduct expenses	353
Total Tax Accruals	(99)
Capitalized Software	(3,467)
Reg-Asset unrecovered plant	37
Mark-to-Market	NIL
Emission Allowances	256
Others	

Taxable Income before State Taxes		(8,229)
State & Local Current Tax		314
Federal Taxable Income		(8,543)
FIT on Current Year Taxable Income		(1,794)
Adjustment due to System Consolidation (a)		(1,794)
NOL Reclass		291
Tax Credit CFWD		(20)
ALT Min Tax		4
ETR Adjustment		(6)
R&D Credit - Current		61
Estimated Tax Currently Payable (b)		330
Current Tax	(a) - (b)	(2,124)
Adjustments of Prior Year's Accruals		1,145
Tax Expense for R/C of Net Operating Loss (Prior Yr)		

Estimated Current Federal Income Taxes	(979)

Foot Notes:
(a) Represents the allocation of the estimated current year net operating tax loss of American Electric Power Company, Inc.
(b) The Company joins in the filing of a consolidated Federal income tax return with its affiliated companies in the AEP system. The allocation of the AEP System's consolidated Federal income tax to the System companies allocates the benefit of current tax losses to the System companies giving rise to them in determining their current tax expense. The tax loss of the System parent company, American Electric Power Company, Inc., is allocated to its subsidiaries with taxable income. With the exception of the loss of the parent company, the method of allocation approximates a separate return result for each company in the consolidating group.
INSTRUCTION 2.
* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal income tax. The computation of actual 2019 System. Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by October 2020. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated federal income tax return is filed

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL TAXES:					
2	INCOME TAX	-1,533,629		-989,633	-1,045,470	
3	FIN 48					
4						
5	FICA - 2018	578,539		4,268,504	4,191,020	
6	Unemployment - 2018	12,502		24,488	23,828	
7						
8	Federal Excise Tax - 2017			586	586	
9	Federal Excise Tax - 2018			2,666	2,666	
10						
11	STATE INC. TAX - FIN 48	-49,346		49,346		
12						
13	STATE OF ILLINOIS:					
14	Income					
15	2012					
16	2016					
17	2017	-66,879				
18	2018	-4,158				
19	2019			-6,080		
20	STATE OF KENTUCKY:					
21	Income					
22	2015					
23	2017	-1,172,523				
24	2019			1,026,305		
25	MULTI 2019			49,346		
26	Local Income Tax			-49,346		
27	Kentucky Franchise Taxes					
28	2017	-225,823				
29	2018	221,200		55,796	51,173	
30	2019			579,996		
31	KY Franchise 2019					
32	NC Franchise 2019					
33	OK Franchise 2019					
34	TN Franchise 2019					
35	License Fee 2018					
36	KY St License Fee 2019			15	15	
37	Unemployment - KY 2018	3,684		10,561	10,167	
38	Municipal Lice Fee - KY 2018					
39	Registration Fees					
40	2017					
41	TOTAL	27,669,270	1,254,293	33,196,237	29,935,750	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2	PUBLIC SER COMM'S-2017			587,589		
3	PUBLIC SER COMM'S-2018		587,589	598,459	1,196,917	
4	UTILITY GR LIC - EDP -	-2,805		-49	-2,854	
5	UTILITY GR LIC - EDP -	1,535		2,356	3,891	
6	UTILITY GR LIC - EDP -			20,777	19,046	
7	USE TAX - 2017					
8	USE TAX - 2018	112,986	33,528	26,250	105,708	
9	USE TAX - 2019			1,272,503	1,201,885	
10						
11	SALES TAX - 2017			404,000		
12	SALES TAX - 2018		316,588			
13	SALES TAX - 2018		316,588		-316,588	
14	REAL & PERS PROP-2013				269,801	
15	REAL & PERS PROP-2014					
16	REAL & PERS PROP-2015			104,327	603,980	
17	REAL & PERS PROP-2016	499,653		724,353	8,180,583	
18	REAL & PERS PROP-2017	7,456,230		-2,148,450	4,044,836	
19	REAL & PERS PROP-2018	16,164,700		16,056,700		
20						
21	PERS PROP LEASED-2016			2	143,218	
22	PERS PROP LEASED-2017	143,216			288,243	
23	PERS PROP LEASED-2018	288,243		387,700	103,411	
24						
25	REAL PROP LEASES-2016				11,081	
26	REAL PROP LEASES-2017	11,081			19	
27	REAL PROP LEASES-2018	19		13,319	13,319	
28						
29	STATE OF WEST VIRGINIA:					
30	Income					
31	2013					
32	2014					
33	2015					
34	2017	324,201				
35	2018	-271,995			90,000	
36	2019			666,483	1,132,000	
37	Franchise					
38	2013					
39	2014					
40						
41	TOTAL	27,669,270	1,254,293	33,196,237	29,935,750	

Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	WV USE - 2017			4,748	11,665	
2	WV USE - 2018	6,917		153,254	119,590	
3						
4	State Bus & Occp Tax-2017			25,229	570,186	
5	State Bus & Occp Tax-2018	544,957		6,300,701	5,757,196	
6						
7	REAL & PERS PROP-2016			2,230	1,533,409	
8	REAL & PERS PROP-2017	1,531,179		-27,049	1,491,208	
9	REAL & PERS PROP-2018	3,009,464		2,936,706		
10	PERS PROP LEASED-2017			-505	1,095	
11	PERS PROP LEASED-2018	1,600		1,600		
12						
13	License Fee - 2017					
14	Muni License Fee - KY 2019			125	250	
15	Municipal Lice Fee - WV				20	
16	Registration Fees					
17	2017					
18						
19	WV State Unemployment -	15,362		44,585	43,450	
20	WV St License Fee-WV				26	
21						
22	OH CAT TAX - 2017			-696	-96	
23	OH CAT TAX - 2018	600		19,273	19,273	
24						
25	STATE OF MICHIGAN:					
26	Income					
27	2015					
28	2017	-2,683				
29	2018	-115			-2,800	
30	2019			-272		
31	OTHER:					
32	REAL/PERS PROP-LA-2017					
33	PA Gross Receipts - Audit	71,358		-71,358		
34	PA Gross Receipts - Audit			68,797	68,797	
35						
36						
37						
38						
39						
40						
41	TOTAL	27,669,270	1,254,293	33,196,237	29,935,750	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-1,477,792		-303,842			-685,791	2
						3
						4
656,023		2,033,358			2,235,146	5
13,162		12,144			12,344	6
						7
		586				8
		2,666				9
						10
					49,346	11
						12
						13
						14
						15
-1						16
-66,879						17
-4,158						18
-6,080		-7,829			1,749	19
						20
						21
						22
-1,172,523						23
1,026,305		987,197			39,108	24
49,346		98,692			-49,346	25
-49,346		-49,346				26
						27
-225,823						28
225,823		55,796				29
579,996					579,996	30
		580,171			-580,171	31
		200			-200	32
		100			-100	33
		100			-100	34
						35
					15	36
4,078		8,675			1,886	37
						38
						39
						40
30,903,196	911,145	29,736,225			3,460,012	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		587,589				2
	598,458	598,459				3
					-49	4
		2,356				5
1,731		20,777				6
						7
		6,097			20,153	8
113,504	42,886	53,930			1,218,573	9
						10
404,000		404,000				11
						12
						13
	269,801					14
						15
		104,327				16
		724,353				17
9,971,414		13,063,500			-15,211,950	18
16,056,700					16,056,700	19
						20
		2				21
						22
284,289		387,700				23
						24
						25
						26
		13,319				27
						28
						29
						30
						31
						32
						33
324,201						34
-361,995						35
-465,517		655,130			11,353	36
						37
						38
						39
						40
30,903,196	911,145	29,736,225			3,460,012	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
					4,748	1
33,664					153,254	2
						3
		21,860			3,369	4
543,505		6,300,701				5
						6
		1,697,018			-1,694,788	7
1,491,207		1,644,426			-1,671,475	8
2,936,706					2,936,706	9
		-505				10
1,600		1,600				11
						12
						13
-125		140			-15	14
-20						15
						16
						17
						18
16,497		15,077			29,508	19
-26						20
						21
		-696				22
		19,273				23
						24
						25
						26
						27
-2,683						28
2,685						29
-272		-315			43	30
						31
						32
		-71,358				33
		68,797				34
						35
						36
						37
						38
						39
						40
30,903,196	911,145	29,736,225			3,460,012	41

Schedule Page: 262.1 Line No.: 11 Column: a

Consist of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Schedule Page: 262.1 Line No.: 12 Column: a

Consist of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Schedule Page: 262.1 Line No.: 13 Column: a

Consist of a prepayment for sales tax only; a collect & remit tax. Beginning in 2009, included for purpose of reporting all prepaid tax activity.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	86			411.4	60	
6							
7							
8	TOTAL	86				60	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
26	Various		5
			6
			7
26			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
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			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	TV Pole Attachments	132,803	454	855,495	862,468	139,776
2						
3	Customer Advance Receipts	2,356,536	142/143	2,356,536	2,799,427	2,799,427
4						
5	Deferred Gain:	114,482	124	12,276		102,206
6	Fiber Optic Agrmts-In Kind Svc					
7	Amortize through June 2026					
8						
9	Deferred Revenue	35,394	451	13,555		21,839
10	Fiber Optic Lines-Sold-Defd Rev					
11	Amortize through January 2025					
12						
13	IPP - System Upgrade Credits	322,778			17,748	340,526
14						
15	Miscellaneous	55,385	Footnote	53,128	597,428	599,685
16						
17	Federal Mitigation Deferral (NSR)	324,494				324,494
18						
19	Noble Energy Deferred Lease	143,855	421	143,855		
20						
21	Contribution Aid of Construction	299,558	107/108	299,558	61,672	61,672
22						
23	Allowances	6,484	186/411	113,734	107,304	54
24						
25	Deferred Revenue	160,051	143	159,282	128,368	129,137
26						
27	Transource WV Recovery	6,877	565	15,630	36,931	28,178
28						
29	Asbestos Accrual	2,793,146	234/925	492,711		2,300,435
30						
31	Deferred Rev-Bonus Lease NC		421	17,076	113,837	96,761
32						
33	NERC Penalties				264,458	264,458
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	6,751,843		4,532,836	4,989,641	7,208,648

Schedule Page: 269 Line No.: 15 Column: c

232/561/566

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities	52,871,071	22,727,581	24,231,420
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	52,871,071	22,727,581	24,231,420
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16	OTHER	-21,130,044		
17	TOTAL (Acct 281) (Total of 8, 15 and 16)	31,741,027	22,727,581	24,231,420
18	Classification of TOTAL			
19	Federal Income Tax	31,741,027	22,727,581	24,231,420
20	State Income Tax			
21	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						51,367,232	4
							5
							6
							7
						51,367,232	8
							9
							10
							11
							12
							13
							14
							15
		254	21,127,381	254	22,633,273	-19,624,152	16
			21,127,381		22,633,273	31,743,080	17
							18
			21,127,381		22,633,273	31,743,080	19
							20
							21

NOTES (Continued)

Schedule Page: 272 Line No.: 16 Column: b

	Balance at Beginning of Year	Balance at End of Year
SFAS 109	(21,130,044)	(19,624,152)
Total	$(21,130,044)	$(19,624,152)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	373,553,798	185,780,150	190,537,841
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	373,553,798	185,780,150	190,537,841
6	Others	-114,688,131		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	258,865,667	185,780,150	190,537,841
10	Classification of TOTAL			
11	Federal Income Tax	258,865,667	185,780,150	190,537,841
12	State Income Tax			
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
				190.1	4,271,719	373,067,826	2
							3
							4
					4,271,719	373,067,826	5
		1823/254	168,165,476	1823/254	175,596,666	-107,256,941	6
							7
							8
			168,165,476		179,868,385	265,810,885	9
							10
			168,165,476		179,868,385	265,810,885	11
							12
							13

NOTES (Continued)

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	499,621	1,129,230	1,628,852
4	Mark-to-Market	63,005,241	12,572,334	6,820,092
5	Capitalized Software - Book	4,519,418	905,049	154,483
6	Emission Allowances	1,915,074		53,845
7	Reg Asset - SFAS 112	589,968	138,538	62,972
8	Other	44,128,024	55,193,871	54,873,634
9	TOTAL Electric (Total of lines 3 thru 8)	114,657,346	69,939,022	63,593,878
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	83,891,487		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	198,548,833	69,939,022	63,593,878
20	Classification of TOTAL			
21	Federal Income Tax	89,756,405	69,863,570	63,065,714
22	State Income Tax	108,792,428	75,452	528,164
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						-1	3
						68,757,483	4
						5,269,984	5
						1,861,229	6
						665,534	7
						44,448,261	8
						121,002,490	9
							10
							11
							12
							13
							14
							15
							16
							17
2,643		1823/254	60,924,329	1823/254	86,142,435	109,112,236	18
2,643			60,924,329		86,142,435	230,114,726	19
							20
2,643			48,389,261		67,193,061	115,360,704	21
			12,535,068		18,949,374	114,754,022	22
							23

NOTES (Continued)

Schedule Page: 276 Line No.: 18 Column: a

Line 18 Other - Detail	Balance at Beginning of Year	Balance at End of Year
Non-Utility	93,077	95,720
SFAS 109	83,798,410	109,016,516
SFAS 133	0	0
Total	$83,891,487	$109,112,236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Home Energy Assistance Program	400,772	Footnote	653,057	975,419	723,134
2						
3	SFAS 109 Deferred FIT	269,355,982	190	322,737,358	309,621,027	256,239,651
4						
5	Kentucky Reliability				152,106	152,106
6						
7	Over Recovered Fuel Cost				222,646	222,646
8						
9	PJM Trans Enhancement Reg Liability	7,614,599	565	4,465,125		3,149,474
10						
11	Capacity Charge Tariff	100,298	440, 442, 444	312,592	212,294	
12						
13	KY- DSM Over Recovery	1,779,249	182	1,664,999		114,250
14						
15	KY Over Recovered PPA Rider	3,864,304	566	4,012,777	1,338,801	1,190,328
16						
17	Netting of Trading Activities related to		182	3,948,420	2,523,298	-1,425,122
18	Unrealized Gains/Losses on Forward Commitments					
19	between Regulated Assets/Liabilities					
20						
21	Unrealized Gain on Forward Commitme	4,084,520	175, 244	4,096,584	1,439,257	1,427,193
22						
23	OSS Margin Sharing		440, 442, 444	344,014	659,881	315,867
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	287,199,724		342,234,926	317,144,729	262,109,527

Schedule Page: 278 Line No.: 1 Column: c

142, 235, 237, 450, 451, 456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	246,422,493	261,173,890
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	151,078,914	157,624,367
5	Large (or Ind.) (See Instr. 4)	151,267,598	159,883,072
6	(444) Public Street and Highway Lighting	1,983,788	1,976,599
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	550,752,793	580,657,928
11	(447) Sales for Resale	37,853,439	42,090,215
12	TOTAL Sales of Electricity	588,606,232	622,748,143
13	(Less) (449.1) Provision for Rate Refunds	94,800	8,033,106
14	TOTAL Revenues Net of Prov. for Refunds	588,511,432	614,715,037
15	Other Operating Revenues		
16	(450) Forfeited Discounts	4,456,905	4,619,385
17	(451) Miscellaneous Service Revenues	639,207	708,038
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	8,255,513	7,042,942
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-107,127	803,259
22	(456.1) Revenues from Transmission of Electricity of Others	24,631,165	24,248,119
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	37,875,663	37,421,743
27	TOTAL Electric Operating Revenues	626,387,095	652,136,780

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
2,051,369	2,158,539	133,978	134,959	2
				3
1,250,640	1,280,235	29,967	30,158	4
2,319,294	2,398,544	1,187	1,149	5
10,467	10,310	329	337	6
				7
				8
				9
5,631,770	5,847,628	165,461	166,603	10
958,632	983,701		24	11
6,590,402	6,831,329	165,461	166,627	12
				13
6,590,402	6,831,329	165,461	166,627	14

Line 12, column (b) includes $ 3,592,356 of unbilled revenues.
Line 12, column (d) includes 35,365 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: b

Detail of Unmetered Sales - 2019

	Revenue	MWH	Average No. of Customers
Residential	5,867,578.00	25,506.00	37,854.00
Commercial	2,752,356.00	14,800.00	6,799.00
Industrial	136,153.00	790.00	222.00
Public Street Lighting	31,364.00	109.00	36.00
Total	8,787,451.00	41,205.00	44,911.00

Schedule Page: 300 Line No.: 10 Column: c

Detail of Unmetered Sales - 2018

	Revenue	MWH	Average No. of Customers
Residential	5,888,725	25,672	38,159
Commercial	2,766,613	14,886	6,852
Industrial	137,028	801	224
Public Street Lighting	31,399	109	36
Total	8,823,765	41,468	45,271

Schedule Page: 300 Line No.: 17 Column: b

Customer Service Revenue including connects, reconnects, disconnects, temporary services and other charges billed to customers.

Schedule Page: 300 Line No.: 21 Column: b

Description	**2019 YTD**	**2018 YTD**
Oth Elect Rev - Demand Side Management Program	(423,872.00)	585,779.00
All Other (Under $250,000)	316,745.00	217,480.00
	(107,127.00)	**803,259.00**

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 Residential Sales					
2	Residential Service	1,995,869	237,971,433	133,476	14,953	0.1192
3	Residential Service - Employee	7,786	908,483	413	18,852	0.1167
4	Res Service Load Mgmt TOD	1,696	187,540	82	20,683	0.1106
5	Residential Service TOD	105	11,713	5	21,000	0.1116
6	Flood Walls	20	2,723	2	10,000	0.1362
7	Kentucky Rider		-648,048			
8	All Outdoor Lighting	25,506	5,867,579			0.2300
9	Subtotal Billed	2,030,982	244,301,423	133,978	15,159	0.1203
10	Unbilled Revenue	20,387	2,121,070			0.1040
11	Total Residential	2,051,369	246,422,493	133,978	15,311	0.1201
12						
13	442 Commercial Sales					
14	Flood Walls	549,607	77,021,003	27,659	19,871	0.1401
15	Small General Service	6,662	803,519	463	14,389	0.1206
16	Medium General Service TOD					
17	Large General Service	383,341	42,153,366	523	732,966	0.1100
18	Gen Service TOD-PA	8,109	1,232,837	1,132	7,163	0.1520
19	Industrial General Service	170,041	13,198,303	24	7,085,042	0.0776
20	All Outdoor Lighting	14,800	2,752,356			0.1860
21	Public Schools	107,278	13,112,097	157	683,299	0.1222
22	Kentucky Rider		-322,000			
23	Mark West HC	1,850	202,105	9	205,556	0.1092
24	Estimated Revenue	83	10,457			0.1260
25	Subtotal Billed	1,241,771	150,164,043	29,967	41,438	0.1209
26	Unbilled Revenue	8,869	914,871			0.1032
27	Total Commercial	1,250,640	151,078,914	29,967	41,734	0.1208
28						
29	442 Industrial Sales					
30	Industrial General Service	340,897	33,327,866	40	8,522,425	0.0978
31	Gen Service TOD-PA	1,655,559	90,846,117	62	26,702,565	0.0549
32	Small General Service	20,569	2,901,426	961	21,404	0.1411
33	Medium General Service					
34	Medium General Service TOD					
35	Large General Service	104,092	12,461,969	120	867,433	0.1197
36	Church Service	185,059	11,065,179	4	46,264,750	0.0598
37	Kentucky Rider		-393,513			
38	All Outdoor Lighting	790	136,153			0.1723
39	Estimated Revenue	6,351	384,896			0.0606
40	Subtotal Billed	2,313,317	150,730,093	1,187	1,948,877	0.0652
41	TOTAL Billed	5,596,405	547,160,437	165,461	33,823	0.0978
42	Total Unbilled Rev.(See Instr. 6)	35,365	3,592,356	0	0	0.1016
43	TOTAL	5,631,770	550,752,793	165,461	34,037	0.0978

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Unbilled Revenue	5,977	537,505			0.0899
2	Total Industrial	2,319,294	151,267,598	1,187	1,953,912	0.0652
3						
4	444 Public Street Lighting					
5	Flood Walls	1,789	299,240	266	6,726	0.1673
6	Medium General Service					
7	Gen Service TOD-PA		1,812	9		
8	Street Lighting	8,437	1,628,938	54	156,241	0.1931
9	Kentucky Rider		3,524			
10	All Outdoor Lighting	109	31,364			0.2877
11	Subtotal Billed	10,335	1,964,878	329	31,413	0.1901
12	Unbilled Revenue	132	18,910			0.1433
13	Total Public Street Lighting	10,467	1,983,788	329	31,815	0.1895
14						
15	Instruction 5. (See Footnote)					
16						
17						
18						
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36						
37						
38						
39						
40						
41	TOTAL Billed	5,596,405	547,160,437	165,461	33,823	0.0978
42	Total Unbilled Rev.(See Instr. 6)	35,365	3,592,356	0	0	0.1016
43	TOTAL	5,631,770	550,752,793	165,461	34,037	0.0978

Schedule Page: 304.1 Line No.: 15 Column: a

FUEL CLAUSE

440 RESIDENTIAL SALES	
Residential Service	$ 1,785,815
Residential Load Mgmt - TOD	1,711
Residential Service TOD	100
Residential Service - EMPLOYEE	7,847
Flood Walls	16
All Outdoor Lighting	18,628
Unbilled Revenue	(452,431)
TOTAL RESIDENTIAL	1,361,686
442 COMMERCIAL SALES	
Public Schools	74,011
Mark West HC	1,373
Industrial General Service	96,608
Large General Service	242,061
Flood Walls	388,020
Medium General Service TOD	6,809
Small General Service	1,563
All Outdoor Lighting	10,682
Estimated Revenue	(156)
Unbilled Revenue	(229,890)
TOTAL COMMERCIAL	591,082
442 INDUSTRIAL SERVICE	
Industrial General Company	236,225
Large General Service	75,835
Flood Walls	13,275
GEN SERVICE TOD-PA	961,741
All Outdoor Lighting	578
Estimated Revenue	(12,923)
Church Service	119,590
Unbilled Revenue	(166,359)
TOTAL INDUSTRIAL	1,227,963
444 PUBLIC STREET LIGHTING	
GEN SERVICE TOD-PA	-
Flood Walls	1,217
Street Lighting	6,028
All Outdoor Lighting	78
Unbilled Revenue	(359)
TOTAL PUBLIC STREET LIGHTING	6,964
TOTAL FUEL CLAUSE	$ 3,187,695

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	CITY OF OLIVE HILL	RQ	KPCO 52			
2	CITY OF VANCEBURG	RQ	KPCO 51			
3	PJM TRANSMISSION FOR RQ	RQ	VARIOUS			
4	AMEREX POWER, LTD	OS	NOTE 1			
5	BGC FINANCIAL LP	OS	NOTE 1			
6	CITIGROUP ENERGY INC.	OS	NOTE 1			
7	COMMONWEALTH EDISON COMPANY	OS	NOTE 1			
8	DP&L POWER SERVICES	OS	NOTE 1			
9	DUKE ENERGY OHIO, INC	OS	NOTE 1			
10	DUQUESNE LIGHT COMPANY	OS	NOTE 1			
11	EOH HOLDINGS, LLC	OS	NOTE 1			
12	EVOLUTION MARKETS FUTURES, LLC	OS	NOTE 1			
13	FIRSTENERGY TRADING SERVICES	OS	NOTE 1			
14	ICAP ENERGY LLC	OS	NOTE 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	ICE TRADE VAULT LLC	OS	NOTE 1			
2	IVG ENERGY, LTD	OS	NOTE 1			
3	MIZUHO SECURITIES USA INC	OS	NOTE 1			
4	MORGAN STANLEY CAPT.	OS	NOTE 1			
5	OHIO POWER COMPANY (AUCTION)	OS	NOTE 1			
6	PJM INTERCONNECTION	OS	NOTE 1			
7	PPL ELECTRIC UTILITIES CORP	OS	NOTE 1			
8	PVM FUTURES, INC.	OS	NOTE 1			
9	RBC CAPITAL MARKET, LLC	OS	NOTE 1			
10	SPSR2 - MAREX SPECTRON	OS	NOTE 1			
11	TAX REFORM ACTIVITY	RQ	NOTE 1			
12	TFS ENERGY FUTURES, LLC	OS	NOTE 1			
13	TRIDENT BROKERAGE SERVICES, LLC	OS	NOTE 1			
14	TULLETT PREBON AMERICAS CORP.	OS	NOTE 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	TVA BULK POWER TRADING	OS	NOTE 1			
2	WELLS FARGO SECURITIES, LLC	OS	NOTE 1			
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
22,867	770,921	1,249,901		2,020,822	1
57,843	1,842,600	2,891,886		4,734,486	2
			-1,633,654	-1,633,654	3
		-8,690		-8,690	4
		-21		-21	5
		-66,875		-66,875	6
1,717		61,578		61,578	7
3,497		170,231		170,231	8
22,201		1,113,621		1,113,621	9
48,450		2,516,623		2,516,623	10
		-8		-8	11
		-6,899		-6,899	12
78,742		3,861,534		3,861,534	13
		-5,435		-5,435	14
80,710	2,613,521	4,141,787	-1,342,860	5,412,448	
877,922	2,708,249	29,732,742	0	32,440,991	
958,632	**5,321,770**	**33,874,529**	**-1,342,860**	**37,853,439**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-8,369		-8,369	1
		-5,828		-5,828	2
		-469,905		-469,905	3
		-106,896		-106,896	4
43,166		2,069,395		2,069,395	5
602,127	2,708,249	16,511,630		19,219,879	6
78,778		3,580,318		3,580,318	7
		-378		-378	8
		667,891		667,891	9
		-246		-246	10
			290,794	290,794	11
		-2,179		-2,179	12
		-2,163		-2,163	13
		-10,340		-10,340	14
80,710	2,613,521	4,141,787	-1,342,860	5,412,448	
877,922	2,708,249	29,732,742	0	32,440,991	
958,632	**5,321,770**	**33,874,529**	**-1,342,860**	**37,853,439**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-756		-7,895		-7,895	1
		-117,952		-117,952	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
80,710	2,613,521	4,141,787	-1,342,860	5,412,448	
877,922	2,708,249	29,732,742	0	32,440,991	
958,632	**5,321,770**	**33,874,529**	**-1,342,860**	**37,853,439**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	4,546,288	3,964,584
5	(501) Fuel	96,775,110	97,128,026
6	(502) Steam Expenses	5,575,379	6,039,074
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	5,604	1,325
10	(506) Miscellaneous Steam Power Expenses	9,066,767	7,903,741
11	(507) Rents	1	
12	(509) Allowances	210,380	256,407
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	116,179,529	115,293,157
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,070,813	2,241,568
16	(511) Maintenance of Structures	1,425,776	1,747,703
17	(512) Maintenance of Boiler Plant	12,039,926	15,091,797
18	(513) Maintenance of Electric Plant	4,506,489	5,496,321
19	(514) Maintenance of Miscellaneous Steam Plant	1,569,575	1,636,607
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	21,612,579	26,213,996
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	137,792,108	141,507,153
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	136,664,091	163,721,698
77	(556) System Control and Load Dispatching	571,100	599,935
78	(557) Other Expenses	698,059	721,964
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	137,933,250	165,043,597
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	275,725,358	306,550,750
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,129,207	2,631,242
84			
85	(561.1) Load Dispatch-Reliability		19
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	396,938	356,979
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	1,151,718	1,518,251
89	(561.5) Reliability, Planning and Standards Development	103,815	75,731
90	(561.6) Transmission Service Studies		16
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	317,484	344,695
93	(562) Station Expenses	223,580	179,061
94	(563) Overhead Lines Expenses	18,313	24,597
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	41,885,396	21,539,138
97	(566) Miscellaneous Transmission Expenses	-1,763,300	5,069,567
98	(567) Rents	305	3,273
99	TOTAL Operation (Enter Total of lines 83 thru 98)	45,463,456	31,742,569
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	71,496	25,172
102	(569) Maintenance of Structures	8,872	7,609
103	(569.1) Maintenance of Computer Hardware	6,377	6,414
104	(569.2) Maintenance of Computer Software	348,041	293,137
105	(569.3) Maintenance of Communication Equipment	7,929	6,302
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	481,292	1,125,054
108	(571) Maintenance of Overhead Lines	5,960,124	5,183,564
109	(572) Maintenance of Underground Lines	122	456
110	(573) Maintenance of Miscellaneous Transmission Plant	103,965	67,587
111	TOTAL Maintenance (Total of lines 101 thru 110)	6,988,218	6,715,295
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	52,451,674	38,457,864

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,085,315	1,156,405
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,085,315	1,156,405
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,085,315	1,156,405
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,013,963	1,054,364
135	(581) Load Dispatching	8,523	1,174
136	(582) Station Expenses	216,929	184,604
137	(583) Overhead Line Expenses	1,108,253	737,448
138	(584) Underground Line Expenses	123,717	101,611
139	(585) Street Lighting and Signal System Expenses	83,942	143,662
140	(586) Meter Expenses	1,235,139	1,166,911
141	(587) Customer Installations Expenses	140,127	122,301
142	(588) Miscellaneous Expenses	4,891,502	4,354,822
143	(589) Rents	1,351,992	1,570,816
144	TOTAL Operation (Enter Total of lines 134 thru 143)	10,174,087	9,437,713
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,909	2,770
147	(591) Maintenance of Structures	65,045	7,509
148	(592) Maintenance of Station Equipment	590,534	426,705
149	(593) Maintenance of Overhead Lines	32,409,184	33,511,571
150	(594) Maintenance of Underground Lines	64,244	86,721
151	(595) Maintenance of Line Transformers	71,848	23,290
152	(596) Maintenance of Street Lighting and Signal Systems	61,865	60,047
153	(597) Maintenance of Meters	45,055	43,492
154	(598) Maintenance of Miscellaneous Distribution Plant	57,031	89,500
155	TOTAL Maintenance (Total of lines 146 thru 154)	33,368,715	34,251,605
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	43,542,802	43,689,318
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	109,895	120,192
160	(902) Meter Reading Expenses	469,942	482,553
161	(903) Customer Records and Collection Expenses	5,429,725	4,983,337
162	(904) Uncollectible Accounts	297,918	74,893
163	(905) Miscellaneous Customer Accounts Expenses	28,897	21,177
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	6,336,377	5,682,152

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	63,903	106,833
168	(908) Customer Assistance Expenses	410,312	2,574,164
169	(909) Informational and Instructional Expenses	68,396	84,694
170	(910) Miscellaneous Customer Service and Informational Expenses	122,992	90,012
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	665,603	2,855,703
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	660	4
175	(912) Demonstrating and Selling Expenses	46,263	61,239
176	(913) Advertising Expenses	1,736	2,848
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	48,659	64,091
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	10,503,956	9,522,165
182	(921) Office Supplies and Expenses	802,618	1,218,750
183	(Less) (922) Administrative Expenses Transferred-Credit	1,120,399	1,439,574
184	(923) Outside Services Employed	2,180,180	2,832,120
185	(924) Property Insurance	834,323	614,421
186	(925) Injuries and Damages	1,585,690	4,039,813
187	(926) Employee Pensions and Benefits	1,535,399	1,527,314
188	(927) Franchise Requirements	124,523	124,655
189	(928) Regulatory Commission Expenses	955,966	-580,628
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	225,386	152,908
192	(930.2) Miscellaneous General Expenses	420,266	357,853
193	(931) Rents	193,429	283,279
194	TOTAL Operation (Enter Total of lines 181 thru 193)	18,241,337	18,653,076
195	Maintenance		
196	(935) Maintenance of General Plant	2,652,705	3,100,636
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	20,894,042	21,753,712
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	400,749,830	420,209,995

Schedule Page: 320 Line No.: 5 Column: b

The portion of account 501 that is excluded from the fuel costs in KPCo's generation formula rate is identified by a query of the general ledger.

Schedule Page: 320 Line No.: 93 Column: b

Generation Step-Up Units' (GSUs) O&M expenses included in KPCo's generation formula rate are the ratio of GSU balances to all investment for plant accounts 352 & 353 multiplied by the balance in O&M accounts 562,569 & 570.

Schedule Page: 320 Line No.: 185 Column: b

The insurance expenses for generation included in KPCo's generation formula rate are identified by a query of the general ledger.

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier’s service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AEP GENERATING COMPANY	RQ	AEG 2			
2	PJM INTERCONNECTION	OS				
3	ROCKPORT PURCHASE POWER	OS				
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,222,042			57,697,972	34,386,321		92,084,293	1
2,144,299				59,579,798		59,579,798	2
			-15,000,000			-15,000,000	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
3,366,341			42,697,972	93,966,119		136,664,091	

Schedule Page: 326 Line No.: 1 Column: a

Affiliated Company

Schedule Page: 326 Line No.: 3 Column: a

Per KPSC Order Case No. 2017-00179, KPCO defers a portion of the non-fuel, non-environmental lease expenses incurred for Rockport Unit 2.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Trans Enhancement Rev - Affil	Various	Various	FNO
5	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO
6	PJM Network Integ Rev - Affil	Various	Various	FNO
7	PJM Point to Point Trans Serv	Various	Various	LFP
8	PJM Trans Owner Admin Revenue	Various	Various	OLF
9	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
10	PJM Power Factor Credits Rev Whlsle	Various	Various	OS
11	RTO Formation Costs Recovery	Various	Various	OS
12	PJM Trans Owner Serv - Affil	Various	Various	OLF
13	East Kentucky Power Cooperative	Various	Various	OLF
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
PJM OATT	Various	Various				1
PJM OATT	Various	Various				2
PJM OATT	Various	Various				3
PJM OATT	Various	Various				4
PJM OATT	Various	Various				5
PJM OATT	Various	Various				6
PJM OATT	Various	Various				7
PJM OATT	Various	Various				8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
See Footnote	Various	Various				13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**0**	**0**	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
2,392,829			2,392,829	1
6,604,834			6,604,834	2
1,349,189			1,349,189	3
223,354			223,354	4
55,277			55,277	5
13,100,265			13,100,265	6
574,683			574,683	7
	94,377		94,377	8
	17,219		17,219	9
		9,892	9,892	10
11,752			11,752	11
	141,659		141,659	12
		55,835	55,835	13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
24,312,183	**253,255**	**65,727**	**24,631,165**	

Schedule Page: 328 Line No.: 1 Column: e

Effective October 1, 2004, the administration of the transmission tariff was turned over to PJM. PJM does not provide any detail except for the total revenue by the major classes listed. OATT (Open Access Transmission Tariff) 3rd revised Volume No. 6

Schedule Page: 328 Line No.: 10 Column: m

Per Proforma ILDSA (Interconnection and Local Delivery Service Agreement) AEP Tariff 3rd Revised Volume No. 6

Schedule Page: 328 Line No.: 13 Column: e

Compensation should be at a rate of one and one-half (1.5) miles per kilowatt-hour for energy delivered persuant to Appendix IV of PJM Service Agreement No. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Schedule Page: 328 Line No.: 13 Column: m

Compensation should be at a rate of one and one-half (1.5) miles per kilowatt-hour for energy delivered persuant to Appendix IV of PJM Service Agreement No. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Concurrent Energy	LFP					112,276	112,276
2	East KY Power Coop							
3	PJM - Enhancements	OS					3,092,269	3,092,269
4	PJM - NITS	OS					38,488,136	38,488,136
5	PJM - Trans Owner	OS					192,715	192,715
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL						41,885,396	41,885,396

Schedule Page: 332 Line No.: 1 Column: g

Concurrent Energy Charges from East Kentucky Power.

Schedule Page: 332 Line No.: 3 Column: g

Transmission Enhancement Charges and Credits (PJM OATT Schedule 12)

Schedule Page: 332 Line No.: 4 Column: g

Network Integration Transmission Service Charges - NITS (PJM OATT Schedule H)

Schedule Page: 332 Line No.: 5 Column: g

Transmission Owner Service (PJM OATT Tariff Sixth Revised Volume No. 1)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	111,598
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	179
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	147,396
7	AEP Service Corporation Billings	45,408
8	Intercompany Allocations	24,160
9	Corporate Money Pool Allocations	14,597
10	Corporate and Fiscal	23,888
11	Prepaid Insurance	
12	Miscellaneous	53,040
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	420,266

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			5,839,732		5,839,732
2	Steam Production Plant	35,883,651	223,101			36,106,752
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	16,603,653				16,603,653
8	Distribution Plant	30,374,261				30,374,261
9	Regional Transmission and Market Operation					
10	General Plant	2,316,321				2,316,321
11	Common Plant-Electric					
12	TOTAL	85,177,886	223,101	5,839,732		91,240,719

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of capitalized software development costs over a 5 year life, and the amortization of costs associated with the Oracle strategic partnership over a 10 year life.

Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM -- COAL/LIGNITE						
13	311 - Big Sandy	15,015					
14	311 - Mitchell	56,949					
15	312 - Big Sandy	77,613					
16	312 - Mitchell	879,678					
17	312 - Mitchell SCR	8,255					
18	314 - Big Sandy	62,446					
19	314 - Mitchell	55,528					
20	315 - Big Sandy	5,119					
21	315 - Mitchell	25,885					
22	316 - Big Sandy	4,054					
23	316 - Mitchell	9,036					
24	TOTAL COAL/LIGNITE	1,199,578					
25							
26	TRANSMISSION						
27	350.1	31,647					
28	352	8,556					
29	352 - Big Sandy	10					
30	352 - Mitchell	72					
31	353	207,045					
32	353 - Big Sandy	603					
33	353 - Mitchell	11,511					
34	353.16	1,199					
35	354	100,343					
36	355	132,940					
37	356	145,685					
38	356.16	1,616					
39	357	326					
40	358	106					
41	358.16	274					
42	TOTAL TRANSMISSION	641,933					
43							
44	DISTRIBUTION						
45	360.1	5,682					
46	361	5,974					
47	362	118,783					
48	362.16	1,139					
49	364	221,560					
50	365	258,115					

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	366	7,516					
13	367	11,728					
14	368	141,038					
15	369	65,360					
16	370	25,283					
17	371	18,733					
18	373	4,306					
19	TOTAL DISTRIBUTION	885,217					
20							
21	GENERAL PLANT						
22	389.1	36					
23	390	24,284					
24	391	2,293					
25	392	15					
26	393	282					
27	394	5,623					
28	395	261					
29	396	6					
30	397	14,733					
31	397.16	1,268					
32	398	1,805					
33	TOTAL GENERAL	50,606					
34							
35	DEPRECIABLE SUM	2,777,334					
36							
37							
38							
39							
40							
41							
42							
43							
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Schedule Page: 336.1 Line No.: 35 Column: b

The depreciable plant base is the November 30, 2019 total company depreciable plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	2016 - Kentucky Power Rate Case		472,465	472,465	938,844
2	KPSC - Case No. 2016-00180				
3					
4	2019 Kentucky IRP Plan		377,066	377,066	
5					
6	2019 Kentucky Environmental Compliance Plan		48,128	48,128	
7					
8	Minor Items < $25,000		58,307	58,307	
9					
10					
11					
12					
13					
14					
15					
16					
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44					
45					
46	TOTAL		955,966	955,966	938,844

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	14,132		928	458,333	480,511	1
							2
							3
	928	377,066					4
							5
	928	48,128					6
							7
	928	58,307					8
							9
							10
							11
							12
							13
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		497,633			458,333	480,511	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection
(2) Transmission
a. Overhead
b. Underground
(3) Distribution
(4) Regional Transmission and Market Operation
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $50,000.)
(7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A(1)b: Generation: Fossil-Fuel Steam	Generation Asset Management
2		3 items under $50,000
3	A(1)e: Generation: Unconventional	1 item under $50,000
4	A(2): Transmission	1 item under $50,000
5	A(3): Distribution	2 items under $50,000
6	A(5): Environment (other than equipment)	2 items under $50,000
7	A(6): Other	2 items under $50,000
8	A(6)a: Alternate Energy	1 item under $50,000
9	A(6)f: Other (Metering)	1 item under $50,000
10	A(6)g: Other (program management)	1 item under $50,000
11	B: Electric R&D External	7 items under $50,000
12	B(1): R&D support to the Research Council	EPRI Annual Portfolio
13	or the Electric Power Research	Transmission EPRI Portfolio
14	Institute	21 items under $50,000
15	B(4): Research Support to Others	3 items under $50,000
16		
17		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
57,680		506	57,680		1
9,256		506	9,256		2
288		506	288		3
3,779		566	3,779		4
2,682		588	2,682		5
20,420		506	20,420		6
13,027		Footnote	13,027		7
6,213		506	6,213		8
1,692		588	1,692		9
1,139		566, 588	1,139		10
	22,606	Footnote	22,606		11
	410,375	506	410,375		12
	61,244	566	61,244		13
	77,403	Footnote	77,403		14
	10,387	506, 566	10,387		15
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506, 566, 588

Schedule Page: 352 Line No.: 11 Column: e

506, 566 & 588

Schedule Page: 352 Line No.: 14 Column: e

506, 566, 588

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	9,324,500		
4	Transmission	173		
5	Regional Market			
6	Distribution	3,595,743		
7	Customer Accounts	1,618,464		
8	Customer Service and Informational	250,367		
9	Sales			
10	Administrative and General	1,563,672		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	16,352,919		
12	Maintenance			
13	Production	6,339,953		
14	Transmission	1,270		
15	Regional Market			
16	Distribution	4,123,297		
17	Administrative and General	713,860		
18	TOTAL Maintenance (Total of lines 13 thru 17)	11,178,380		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	15,664,453		
21	Transmission (Enter Total of lines 4 and 14)	1,443		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	7,719,040		
24	Customer Accounts (Transcribe from line 7)	1,618,464		
25	Customer Service and Informational (Transcribe from line 8)	250,367		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	2,277,532		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	27,531,299	1,747,132	29,278,431
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	27,531,299	1,747,132	29,278,431
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	11,618,147	737,285	12,355,432
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	11,618,147	737,285	12,355,432
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,556,647	162,244	2,718,891
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,556,647	162,244	2,718,891
77	Other Accounts (Specify, provide details in footnote):			
78	152 - Fuel Stock Undistributed	3,334,566		3,334,566
79	163 - Stores Expense Undistributed	1,416,057	-1,416,057	
80	183 - Prelim Survey	-1,296	1,296	
81	184 - Clearing Accounts	1,231,900	-1,231,900	
82	185 - ODD Temporary Facilities	40,910		40,910
83	186 - Misc Deferred Debits	666,531		666,531
84	188 - Research & Development	-438		-438
85	401 - Operation Expense - Nonassociated	2,807		2,807
86	426 - Political Activities	14,044		14,044
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	6,705,081	-2,646,661	4,058,420
96	TOTAL SALARIES AND WAGES	48,411,174		48,411,174

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				59,502,870
3	Net Sales (Account 447)				(25,882,026)
4	Transmission Rights				(8,898,666)
5	Ancillary Services				2,008,722
6	Other Items (list separately)				
7	Congestion				8,911,405
8	Operating Revenues				229,022
9	Transmission Purchase Expense				1,579,592
10	Transmission Losses				6,900,431
11	Meter Corrections				20,028
12	Inadvertent				(8,898)
13	Capacity Credits				(2,422,966)
14	Miscellaneous				
15					
16					
17					
18					
19					
20					
21					
22					
23					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL				41,939,514

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year: Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year: Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

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The final grandfathered contracts (under the AEP OATT) expired 12/31/2010. Currently, services are provided under the SPP and PJM OATTs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Schedule Page: 400 Line No.: 1 Column: b

Kentucky Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	5,631,770
3	Steam	3,582,409	23	Requirements Sales for Resale (See instruction 4, page 311.)	80,710
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	877,922
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other		27	Total Energy Losses	358,348
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	6,948,750
9	Net Generation (Enter Total of lines 3 through 8)	3,582,409			
10	Purchases	3,366,341			
11	Power Exchanges:				
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received				
17	Delivered				
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	6,948,750			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	710,606	94,425	1,296	31	800
30	February	569,518	84,958	1,009	1	1000
31	March	603,778	82,546	1,124	6	800
32	April	505,428	79,538	944	1	800
33	May	505,568	57,582	908	28	1700
34	June	523,075	55,360	960	27	1700
35	July	732,240	215,515	985	19	1700
36	August	613,470	106,812	993	19	1700
37	September	601,799	123,348	976	11	1700
38	October	475,879	40,158	946	1	1700
39	November	541,664	33,012	1,110	13	800
40	December	565,725	25,549	1,087	19	800
41	TOTAL	6,948,750	998,803			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) ☐ An Original (2) ☒ A Resubmission	04/28/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Big Sandy* (b)			Plant Name: *Mitchell-KEPCo Share* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	STEAM			STEAM		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	CONVENTIONAL			OUTDOOR BOILER		
3	Year Originally Constructed	1963			1971		
4	Year Last Unit was Installed	2016			1971		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	280.50			817.00		
6	Net Peak Demand on Plant - MW (60 minutes)	301			755		
7	Plant Hours Connected to Load	5430			6850		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	280			780		
10	When Limited by Condenser Water	280			780		
11	Average Number of Employees	33			101		
12	Net Generation, Exclusive of Plant Use - KWh	1061768000			2520641000		
13	Cost of Plant: Land and Land Rights	1734844			3103945		
14	Structures and Improvements	15089607			56949572		
15	Equipment Costs	149535925			978391841		
16	Asset Retirement Costs	4241543			8961749		
17	Total Cost	170601919			1047407107		
18	Cost per KW of Installed Capacity (line 17/5) Including	608.2065			1282.0160		
19	Production Expenses: Oper, Supv, & Engr	688937			3857188		
20	Fuel	34165702			65211204		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	18596			5556782		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	5794			-190		
26	Misc Steam (or Nuclear) Power Expenses	4403950			4662817		
27	Rents	0			0		
28	Allowances	46498			163882		
29	Maintenance Supervision and Engineering	337349			1733464		
30	Maintenance of Structures	935620			490156		
31	Maintenance of Boiler (or reactor) Plant	1146617			10893310		
32	Maintenance of Electric Plant	789518			3719971		
33	Maintenance of Misc Steam (or Nuclear) Plant	760373			808957		
34	Total Production Expenses	43298954			97097541		
35	Expenses per Net KWh	0.0408			0.0385		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCFs			Tons	Barrels	
38	Quantity (Units) of Fuel Burned	8203548	0	0	1006273	30189	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1224000	0	0	12406	134355	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.283	0.000	0.000	55.850	90.655	0.000
41	Average Cost of Fuel per Unit Burned	3.703	0.000	0.000	60.243	92.521	0.000
42	Average Cost of Fuel Burned per Million BTU	3.025	0.000	0.000	2.428	16.396	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.029	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	9981.000	0.000	0.000	9974.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Mitchell- Total* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
STEAM			1
OUTDOOR BOILER			2
1971			3
1971			4
1633.00	0.00	0.00	5
1509	0	0	6
6850	0	0	7
0	0	0	8
1560	0	0	9
1560	0	0	10
202	0	0	11
5041281000	0	0	12
6207890	0	0	13
113721651	0	0	14
1954536576	0	0	15
15981437	0	0	16
2090447554	0	0	17
1280.1271	0	0	18
6902227	0	0	19
114814691	0	0	20
0	0	0	21
11279527	0	0	22
0	0	0	23
0	0	0	24
-345	0	0	25
9968027	0	0	26
1	0	0	27
163431	0	0	28
3242600	0	0	29
979991	0	0	30
21985931	0	0	31
7434345	0	0	32
1617974	0	0	33
178388400	0	0	34
0.0354	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Coal	Oil								36
Tons	Barrels								37
2012546	60378	0	0	0	0	0	0	0	38
12406	134355	0	0	0	0	0	0	0	39
55.850	90.655	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
60.168	92.521	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
2.425	16.396	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.024	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
9974.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: c

Plant Name: Mitchell - This plant is owned jointly by Respondent and Wheeling Power Company, also a subsidiary of American Electric Power,Inc.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
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			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
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Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
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						9
						10
						11
						12
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Name of Respondent Kentucky Power Company	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	3	0.13		1
2	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	3	24.20		1
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	3	4.79		1
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	12.65		1
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	3.04		1
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	3	58.26		1
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	3	154.74		1
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	3	8.36		1
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	1	45.62		1
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	3	0.72		1
11	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	1	1.09		1
12	0136 WOOTEN EXTENSION		161.00	161.00	3			1
13	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	12.08		1
14	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	14.77		1
15	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	3	16.30		2
16	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	3	0.33		1
17	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	3	1.10	1.10	1
18	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	5.91		1
19	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	3	23.25		1
20	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	3	2.30		1
21	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	1	16.09	16.92	1
22	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	3	0.48		2
23	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	1.48		1
24	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	3.31		1
25	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	3	30.88		1
26	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	2	22.86		1
27	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	1	0.01		1
28	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	3	0.71	14.41	1
29	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	1	0.38		1
30	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	1	8.09		1
31	0115 CHADWICK	COALTON	138.00	138.00	1	0.98		1
32	0133 CHADWICK		138.00	138.00				
33	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	1	5.08	1.58	1
34	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	1	25.83		1
35	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	3	0.63		
36					TOTAL	1,286.23	40.17	66

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	0120 HATFIELD	SPRIGG	138.00	138.00	1	5.88		1
2	0121 HATFIELD	INEZ	138.00	138.00	1	14.67		1
3	0122 INEZ	LOVELY	138.00	138.00	1	6.86		1
4	0126 INEZ	MARTIKI	138.00	138.00	1	0.33		1
5	0127 BIG SANDY	INEZ	138.00	138.00	3	25.08		1
6	0106 DORTON	FLEMING	138.00	138.00	1	6.81		1
7	0106 DORTON	FLEMING	138.00	138.00	3	0.83		
8	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	1	32.60		1
9	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	1	0.01		1
10	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00				
11	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	3	0.22		2
12	0130 JOHNS CREEK	SPRIGG	138.00	138.00	3	13.00		
13	0131 BAKER	BIG SANDY EXT.	138.00	138.00	3	1.00		1
14	0131 BAKER	BIG SANDY EXT.	138.00	138.00	1	0.05		2
15	0128 INEZ	JOHNS CREEK	138.00	138.00	3	17.00		
16	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	3	22.11		
17	0132 GRANGSTON LOOP		138.00	138.00	3	0.84		2
18	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	3	8.30		1
19	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	3	1.40		2
20	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	3	1.40		2
21	0139 MORGAN FORK	BETSY LANE	138.00	138.00	3	0.10		1
22	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	3	0.10		1
23	0140 BONNYMAN	SOFT SHELL	138.00	138.00	3	0.88		2
24	0140 BONNYMAN	SOFT SHELL	138.00	138.00	1	19.15		1
25	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	5.89		1
26	0119 BETSY LAYNE	ALLEN	46.00	138.00	3	0.22		2
27	0119 BETSY LAYNE	ALLEN	46.00	138.00	1	0.33		2
28	0142 STANVILLE		138.00	138.00	1	0.42		1
29								
30	LINES < 132KV		69.00	69.00		594.30	6.16	
31								
32	Line cost and expense are	not available by individual						
33	transmission line	Total shown in Column j - p						
34								
35								
36					TOTAL	1,286.23	40.17	66

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 MCMA								1
954 MCMA								2
								3
4-954 KCM ACSR								4
								5
								6
1351.5 KCM ACSR								7
954 KCM ACSR								8
500 KCM CU								9
759 KCM ACSR								10
795 KCM ACSR								11
795 KCM ACSR								12
556.5 KCM ACSR								13
795 KCM ACSR								14
795 KCM ACSR								15
1033.5 KCM ACSR								16
397.5 MA								17
397.5 MCMCU								18
								19
636 MCMA								20
								21
397 MCMA								22
954KCM ACSR								23
795KCM ACSR								24
636KCM ACSR								25
636KCM ACSR								26
636KCM ACSR								27
795 MCMA								28
								29
795 MCMA								30
795 MCMA								31
								32
556.5 MCM								33
795 MCMA								34
1590 KCM								35
	34,734,694	380,988,155	415,722,849	18,313	5,960,246		5,978,559	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1033 MCM								1
1033.5 VAR								2
1033.5 VAR								3
1033.5 VAR								4
795 MCMA								5
795 MCMA								6
795 MCMA								7
397 MCMA								8
1033.5 VAR								9
								10
795 ACSR								11
1033 MCM								12
1351 KCM								13
2 - 1351KCM ACSR								14
2-556.5 MCM								15
1033.5KCM ACSR								16
556.5 KCM ACSR								17
795 ACSR								18
1590 ACSR								19
1590 ACSR								20
795 ACSR								21
795 ACSR								22
1590 KCM ACSS								23
1590 KCM ACSS								24
795KCM ACSR								25
1033.5KCM ACSR								26
1033.5KCM ACSR								27
1033.5KCM ACSR								28
								29
								30
								31
	34,734,694	380,988,155	415,722,849	18,313	5,960,246		5,978,559	32
								33
								34
								35
	34,734,694	380,988,155	415,722,849	18,313	5,960,246		5,978,559	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	NO LINES ADDED						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
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Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ALLEN (KP) - KY	D	46.00		
2	ALLEN (KP) - KY	D	46.00	12.00	
3	ASHLAND - KY	D	69.00		
4	ASHLAND - KY	D	69.00	12.00	
5	BAKER 345KV - KY	T	345.00	138.00	34.50
6	BAKER 765KV - KY	T	69.00	4.00	
7	BAKER 765KV - KY	T	765.00	345.00	34.50
8	BAKER 765KV - KY	T	69.00	12.00	
9	BAKER 765KV - KY	T	69.00	12.00	
10	BARRENSHE - KY	D	69.00	12.00	
11	BEAVER CREEK - KY	T	138.00		
12	BEAVER CREEK - KY	T	138.00		
13	BEAVER CREEK - KY	T	138.00	69.00	46.00
14	BEAVER CREEK - KY	T	138.00	34.50	
15	BECKHAM - KY	D	138.00		
16	BECKHAM - KY	D	138.00	34.50	
17	BEEFHIDE - KY	D	138.00	34.50	
18	BELFRY - KY	D	46.00	12.00	
19	BELHAVEN - KY	D	138.00	13.09	
20	BELLEFONTE 138KV - KY	T	138.00	13.09	
21	BELLEFONTE 138KV - KY	T	138.00	69.00	34.50
22	BELLEFONTE 138KV - KY	T	138.00	35.00	
23	BELLEFONTE 69KV - KY	T	69.00		
24	BIG SANDY 138KV - KY	T	138.00	13.09	
25	BIG SANDY 138KV - KY	T	138.00	34.50	
26	BIG SANDY 138KV - KY	T	138.00	69.50	13.20
27	BLUE GRASS - KY	D	69.00	12.00	
28	BONNYMAN - KY	T	69.00	34.50	
29	BONNYMAN - KY	T	138.00	70.50	13.00
30	BULAN - KY	D	69.00	12.00	
31	BURDINE - KY	D	46.00	12.00	
32	BURTON - KY	D	46.00	12.00	
33	BUSSEYVILLE - KY	D	138.00	34.50	
34	CEDAR CREEK - KY	T	138.00	69.00	46.00
35	CHADWICK - KY	T	138.00	69.00	34.50
36	CHAVIES - KY	D	69.00	12.00	
37	CHAVIES - KY	D	69.00		
38	COALTON - KY	D	69.00	12.00	
39	COALTON - KY	D	69.00		
40	COLEMAN - KY	D	69.00	34.50	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COLEMAN - KY	D	69.00	12.00	
2	COLLIER - KY	D	69.00	34.00	
3	COLLIER - KY	D	69.00		
4	COMBS - KY	D	69.00		
5	COMBS - KY	D	69.00	12.00	
6	DAISY - KY	D	69.00		
7	DAISY - KY	D	69.00	12.00	
8	DEWEY - KY	T	138.00	34.50	
9	DEWEY - KY	T	138.00	69.00	12.00
10	DEWEY - KY	T	69.00		
11	DORTON - KY	T	138.00	70.50	46.00
12	DRAFFIN - KY	D	46.00	12.00	
13	EAST PRESTONSBURG - KY	D	46.00	12.00	
14	ELWOOD (KP) - KY	D	46.00	34.50	6.50
15	ELWOOD (KP) - KY	D	46.00		
16	ENGLE - KY	D	69.00	34.50	
17	FALCON - KY	D	69.00	12.00	
18	FALCON - KY	D	69.00	46.00	
19	FEDS CREEK - KY	D	69.00	12.00	
20	FISHTRAP - KY	D	69.00	12.00	
21	FLEMING - KY	T	138.00	69.00	46.00
22	FLEMING - KY	T	69.00		
23	FLEMING - KY	T	69.00	12.00	
24	FORDS BRANCH - KY	D	46.00	34.50	12.00
25	FORDS BRANCH STEPDOWN - KY	D	34.50	12.00	
26	FORTY SEVENTH STREET - KY	D	69.00	13.09	
27	GARRETT (KP) - KY	T	46.00	12.00	
28	GRAHN - KY	D	69.00	12.00	
29	GRAYS BRANCH - KY	D	69.00	12.00	
30	GRAYSON - KY	D	69.00	12.00	
31	HADDIX - KY	D	69.00	34.50	
32	HADDIX - KY	D	69.00		
33	HATFIELD (KP) - KY	T	138.00	69.00	46.00
34	HAYWARD - KY	D	69.00	13.09	
35	HAZARD - KY	T	138.00	36.20	
36	HAZARD - KY	T	69.00		
37	HAZARD - KY	T	138.00	69.00	12.00
38	HAZARD - KY	T	34.50	12.00	
39	HAZARD - KY	T	138.00		
40	HAZARD - KY	T	161.00	138.00	11.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HENRY CLAY - KY	D	46.00	34.50	
2	HENRY CLAY - KY	D	46.00		
3	HIGHLAND (KP) - KY	D	69.00		
4	HIGHLAND (KP) - KY	D	69.00	13.09	
5	HITCHINS - KY	D	69.00	13.09	
6	HOODS CREEK - KY	D	69.00	12.00	
7	HOWARD COLLINS - KY	D	69.00	12.00	
8	INDEX - KY	D	69.00	12.00	
9	INEZ - KY	T	138.00	69.00	13.09
10	INEZ - KY	T	69.00		
11	INEZ - KY	T	138.00		
12	JACKSON - KY	D	69.00	12.00	
13	JACKSON - KY	D	69.00		
14	JEFF - KY	D	69.00	36.20	
15	JENKINS - KY	D	69.00	12.00	
16	JOHNS CREEK - KY	T	69.00		
17	JOHNS CREEK - KY	T	138.00	69.00	34.00
18	JOHNS CREEK - KY	T	138.00		
19	KENWOOD - KY	D	46.00		
20	KENWOOD - KY	D	46.00	12.00	
21	KEYSER - KY	D	69.00	12.00	
22	KIMPER - KY	D	69.00	12.00	
23	LESLIE - KY	T	69.00		
24	LESLIE - KY	T	69.00	34.50	
25	LESLIE - KY	T	161.00	69.00	12.00
26	LOVELY - KY	D	138.00	34.00	
27	MANSBACH - KY	D	69.00	4.00	
28	MAYKING - KY	D	69.00	12.00	
29	MAYO TRAIL - KY	D	69.00		69.00
30	MCKINNEY - KY	D	46.00	34.00	
31	MCKINNEY - KY	D	34.50	12.00	
32	MIDDLE CREEK - KY	D	46.00	12.00	
33	MORGAN FORK - KY	T	138.00		
34	NEW CAMP - KY	D	69.00	12.00	
35	OLIVE HILL - KY	D	69.00	4.00	
36	OLIVE HILL - KY	D	69.00	12.00	
37	PRESTONSBURG - KY	D	46.00	13.09	
38	PRESTONSBURG - KY	D	46.00		
39	PRINCESS - KY	D	69.00		
40	RACELAND - KY	D	69.00	2.40	

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	REEDY COAL - KY	D	69.00	34.00	
2	RUSSELL - KY	D	69.00	12.00	
3	RUSSELL FORK - KY	D	69.00	12.00	
4	SALISBURY (KP) - KY	D	46.00	13.09	
5	SECOND FORK - KY	D	69.00		
6	SECOND FORK - KY	D	69.00	12.00	
7	SHAMROCK - KY	D	69.00	34.50	
8	SIDNEY - KY	D	69.00	12.00	
9	SILOAM - KY	D	69.00	12.00	
10	SLEMP - KY	D	69.00	34.00	
11	SLEMP - KY	D	69.00	34.50	
12	SOFT SHELL - KY	D	138.00	34.50	
13	SOUTH PIKEVILLE - KY	D	69.00	13.09	
14	SOUTH SHORE - KY	D	69.00	13.09	
15	SPRING FORK - KY	D	46.00	7.20	
16	STINNETT - KY	D	161.00	34.00	7.20
17	STINNETT - KY	D	161.00	34.50	7.20
18	STINNETT - KY	D	161.00	34.50	7.20
19	TENTH STREET - KY	D	69.00	13.09	
20	THELMA - KY	T	46.00		
21	THELMA - KY	T	138.00		
22	THELMA - KY	T	138.00	69.00	12.00
23	THELMA - KY	T	138.00	69.00	46.00
24	TOM WATKINS - KY	D	69.00	12.00	
25	TOPMOST - KY	D	138.00	13.09	
26	VICCO - KY	D	138.00	34.50	
27	WEEKSBURY - KY	D	69.00	12.00	
28	WEST PAINTSVILLE - KY	D	69.00	12.00	
29	WHITESBURG - KY	D	69.00		
30	WHITESBURG - KY	D	69.00	12.00	
31	WORTHINGTON - KY	D	69.00	12.00	
32	WURTLAND - KY	D	69.00	12.00	
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
			STATCAP	1	13	1
6	1					2
			STATCAP	1	16	3
22	1					4
	1					5
3		1				6
1500	3					7
3		1				8
11		1				9
25	1					10
			REACTOR	3		11
			STATCAP	4	226	12
146	2					13
30	1					14
			STATCAP	1	43	15
30	1					16
20	1					17
11	1					18
20	1					19
22	1					20
308	2					21
45	1					22
			STATCAP	1	14	23
20	1					24
20	1					25
129	1					26
11	1					27
30	1					28
130	1					29
9	1					30
8	1					31
6	1					32
55	2					33
90	1					34
200	1					35
4	1					36
			STATCAP	1	10	37
25	1					38
			STATCAP	1	14	39
20	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4	1					1
25	1					2
			STATCAP	1	10	3
			STATCAP	1	13	4
8	1					5
			STATCAP	1	13	6
5	1					7
25	1					8
90	1					9
			STATCAP	1	27	10
144	2					11
11	1					12
20	1					13
25	1					14
			STATCAP	1	14	15
20	1					16
20	1					17
20	1					18
22	1					19
4	1					20
130	1					21
			STATCAP	1	14	22
20	1					23
30	1					24
4	1					25
20	1					26
11	1					27
3	1					28
5	1					29
20	1					30
25	1					31
			STATCAP	1	5	32
60	1					33
9	1					34
30	1					35
			STATCAP	1	24	36
180	2					37
9	1					38
			STATCAP	1	32	39
135	3					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1					1
			STATCAP	1	10	2
			STATCAP	1		3
25	1					4
25	1					5
11	1					6
31	2					7
9	1					8
50	1					9
			STATCAP	1	10	10
			STATCAP	2	106	11
15	2					12
			STATCAP	1	10	13
30	1					14
11	1					15
			STATCAP	1	10	16
90	1					17
			STATCAP	1	53	18
			STATCAP	1	7	19
20	1					20
20	1					21
9	1					22
			STATCAP	1	14	23
30	1					24
90	1					25
30	1					26
9	1					27
20	1					28
25	1					29
20	1					30
7	1					31
4	1					32
			STATCAP	1	43	33
20	1					34
5	1					35
8	1					36
10	1					37
			STATCAP	1	9	38
			STATCAP	1	22	39
8	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
22	1					2
4	1					3
20	1					4
			STATCAP	1	14	5
8	1					6
11	1					7
20	1					8
5	1					9
20	1					10
11	1					11
30	1					12
25	1					13
8	1					14
1	1					15
15	1					16
22		1				17
22	1					18
25	1					19
			STATCAP	1	7	20
			STATCAP	1	32	21
90	1					22
70	1					23
11	1					24
20	1					25
30	1					26
6	1					27
25	1					28
			STATCAP	1	13	29
36	2					30
2	1					31
20	1					32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Kentucky Power Company	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 04/28/2020	Year/Period of Report End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	AEPSC	935	1,558,663
3	Audit Services	AEPSC	920, 923	485,594
4	Barging	I&M	151	4,811,733
5	Central Machine Shop	APCo	Footnote	1,415,466
6	Construction Services	AEPSC	107,108	30,954,380
7	Customer Accounts Expenses	AEPSC	901, 902, 903, 905	3,375,322
8	Distribution Expenses - Maintenance	AEPSC	Footnote	496,757
9	Distribution Expenses - Operation	AEPSC	Footnote	1,415,186
10	Factored Customer A/R Bad Debts	AEP Credit	426.5	1,310,980
11	Factored Customer A/R Expense	AEP Credit	426.5	959,165
12	Fuel & Storeroom Services	AEPSC	152,163	3,696,689
13	Materials and Supplies	APCo	Footnote	2,453,883
14	Materials and Supplies	OPCo	Footnote	447,329
15	Other Power Supply Expense	AEPSC	556-557	1,623,114
16	Research and Other Services	AEPSC	184,186,188	2,201,729
17	Steam Power Generation - Maintenance	AEPSC	510-514	4,361,957
18	Steam Power Generation - Operation	AEPSC	Footnote	6,959,417
19	Transmission Expenses - Maintenance	AEPSC	Footnote	1,603,404
20	**Non-power Goods or Services Provided for Affiliate**			
21	Building and Property Leases	AEPSC	454	709,277
22	Construction Services	KYTCo	107	341,389
23	Fleet and Vehicle Charges	AEPSC	Footnote	4,238,236
24	Materials and Supplies	APCo	154	2,587,025
25	O&M Services for Jointly Owned Facility- Mitchell	WPCo	Footnote	62,898,170
26	Urea	APCo	154	374,065
27	Use of Jointly Owned Facility	KYTCo	454	297,457
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Steam Power Generation - Operation	WPCo	501,502	759,921

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [ ] An Original (2) [X] A Resubmission	04/28/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Environmental Services	AEPSC	920, 923	258,127
4	Customer Support	AEPSC	920, 923	265,493
5	Corporate Accounting	AEPSC	920,923	1,593,074
6	Corporate Communications	AEPSC	920,923	380,718
7	Corporate Planning & Budgeting	AEPSC	920,923	631,854
8	Human Resources	AEPSC	920,923	858,362
9	Information Technology	AEPSC	920,923	3,226,809
10	Legal GC/Administration	AEPSC	920,923	2,988,202
11	Real Estate & Workplace Svcs	AEPSC	920,923	1,087,124
12	Regulatory Services	AEPSC	920,923	594,990
13	Strategy & Innovation	AEPSC	920,923	403,997
14	Transmission Expenses - Operation	AEPSC	Footnote	4,390,194
15	Treasury & Risk	AEPSC	920,923	1,024,219
16	Urea	APCo	154	664,054
17	Civil & Political Activities and Other Svcs	AEPSC	Footnote	332,788
18	Construction Services	APCo	107,108	290,651
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
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568,569,569.1,569.2,569.3,570,571,572,573

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Cost related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

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107,108,154,186,401,402,408,421,426,456,500,501,502,505,506,510-514,557,920-926,928,930,931,935

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