APPENDIX

#1

Company Response to Staff's Post-Hearing Data Request 2, Attachment 1

Exhibit AEV 8

Calculation of Proposed Peaking Unit Equivalent Cost Adder

	Firm Gas Adder Calculation					
	$/MMBtu	Heat Rate	$/MWh Adder	Startup Costs $/MWh	Variable O&M $/MWh	Total $/MWh Adder
January	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
February	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
March	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
April	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
May	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
June	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
July	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
August	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
September	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
October	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
November	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
December	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87

Firm Reservation Rate, per Big Sandy Agreement ($.20/MMBtu)
Firm Surcharges, as stated in TCO tariff ($.0545/MMBtu)
Firm Transportation Commodity Rate ($0.0104/MMBtu)
Transportation Retainage, as stated in TCO tariff (1.893% or ~$0.058 on $3 gas)
Park and Lend Rate, as stated in the TCO tariff ($0.1939 winter and $0.1327 summer)
FERC Annual Charge Adjustment (ACA) ($0.0013/MMbtu)

Ceredo Combustion Turbines
Historical Variable O&M Costs

Year	Month	Unitname	MWH	Total Accounting Rate	Fuel Rate 151	Handling Rate 152	O&M Cost / MWH	VOM Cost
2013	January	Ceredo	1,224	65.28	13.62	0.45	6.45	7,895
2013	February	Ceredo	306	66.92	15.56	2.06	5.92	1,812
2013	March	Ceredo	728	66.42	16.83	1.84	8.94	6,508
2013	April	Ceredo	0	0	0	0	0.00	-
2013	May	Ceredo	662	74.83	15.23	3.90	7.17	4,747
2013	June	Ceredo	86	116.04	12.73	6.11	40.36	3,471
2013	July	Ceredo	2,983	59.18	15.25	0.27	1.30	3,878
2013	August	Ceredo	0	0	0	0	0.00	-
2013	September	Ceredo	645	54.67	13.79	1.36	6.71	4,328
2013	October	Ceredo	0	0	0	0	0.00	-
2013	November	Ceredo	100	184.66	24.79	8.04	9.31	931
2013	December	Ceredo	697	69.97	16.24	2.16	7.51	5,234
2014	January	Ceredo	11,707	27.35	27.24	0.12	0.72	8,429
2014	February	Ceredo	8,880	33.81	33.62	0.20	1.10	9,768
2014	March	Ceredo	6,411	28.58	28.33	0.25	0.81	5,193
2014	April	Ceredo	510	21.76	19.48	2.28	23.62	12,044
2014	May	Ceredo	876	18.61	17.38	1.24	5.07	4,441
2014	June	Ceredo	88	2,223	1,067	1,157	137.08	12,063
2014	July	Ceredo	155	2,744	2,057	687	49.90	7,734
2014	August	Ceredo	366	6,402	5,545	857	25.06	9,172
2014	September	Ceredo	70	567	567	0	246.72	17,270
2014	October	Ceredo	501	7,129	7,367	-238	26.03	13,039
2014	November	Ceredo	0	0	0	0	0.00	-
2014	December	Ceredo	507	14.96	13.78	1.18	21.54	10,918
2015	January	Ceredo	1,764	15.26	14.69	0.56	5.51	9,720
2015	February	Ceredo	3,405	16.53	16.21	0.31	1.20	4,086
2015	March	Ceredo	909	14.43	13.76	0.67	3.06	2,777
2015	April	Ceredo	0	0.00	0.00	0.00	0.00	-
2015	May	Ceredo	5,224	11.32	11.21	0.11	1.16	6,060
2015	June	Ceredo	3,134	9.36	9.17	0.19	2.00	6,268
2015	July	Ceredo	2,994	11.39	11.21	0.18	2.09	6,242
2015	August	Ceredo	1,347	11.07	10.55	0.52	3.71	4,991
2015	September	Ceredo	1,647	10.65	10.09	0.56	7.46	12,287
2015	October	Ceredo	0	0.00	0.00	0.00	0.00	-
2015	November	Ceredo	395	9.63	7.74	1.90	4.19	1,653
2015	December	Ceredo	0	0.00	0.00	0.00	0.00	-
			58,321				3.48 Avg VOM $/MWh	202,956

Ceredo 1	Date	Start Cost					
	11/4/2016	$ 2,940.67					
	11/5/2016	$ 2,932.65					
	11/6/2016	$ 2,932.65		$ 3,005.84	Avg		
	11/4/2016	$ 2,940.67			min run	MW	$/MWh start cost
	11/5/2016	$ 2,932.65	use	3000	1	100	30
	11/6/2016	$ 2,932.65					
	11/7/2016	$ 2,932.65					
	11/8/2016	$ 2,950.27					
	11/9/2016	$ 2,953.19					
	11/10/2016	$ 2,945.89					
	11/11/2016	$ 2,934.22					
	11/12/2016	$ 2,929.11					
	11/13/2016	$ 2,929.11					
	11/14/2016	$ 2,929.11					
	11/15/2016	$ 2,945.89					
	11/16/2016	$ 2,962.68					
	11/17/2016	$ 2,967.78					
	11/18/2016	$ 2,949.54					
	11/19/2016	$ 2,970.70					
	11/20/2016	$ 2,970.70					
	11/21/2016	$ 2,970.70					
	11/22/2016	$ 2,988.94					
	11/23/2016	$ 2,983.84					
	11/24/2016	$ 2,981.65					
	11/25/2016	$ 2,981.65					
	11/26/2016	$ 2,981.65					
	11/27/2016	$ 2,981.65					
	11/28/2016	$ 2,981.65					
	11/29/2016	$ 2,993.32					
	11/30/2016	$ 3,001.35					
	12/1/2016	$ 3,024.37					
	12/2/2016	$ 3,030.21					
	12/3/2016	$ 3,028.02					
	12/4/2016	$ 3,028.02					
	12/5/2016	$ 3,028.02					
	12/6/2016	$ 3,044.07					
	12/7/2016	$ 3,056.47					
	12/8/2016	$ 3,060.85					
	12/9/2016	$ 3,056.47					
	12/10/2016	$ 3,063.04					
	12/11/2016	$ 3,063.04					
	12/12/2016	$ 3,063.04					
	12/13/2016	$ 3,049.18					
	12/14/2016	$ 3,049.18					
	12/15/2016	$ 3,044.80					
	12/16/2016	$ 3,048.45					

12/17/2016	$	3,034.58
12/18/2016	$	3,034.58
12/19/2016	$	3,034.58
12/20/2016	$	3,047.72
12/21/2016	$	3,032.39
12/22/2016	$	3,044.80
12/23/2016	$	3,047.72
12/24/2016	$	3,048.45
12/25/2016	$	3,048.45
12/26/2016	$	3,048.45
12/27/2016	$	3,048.45
12/28/2016	$	3,052.82
12/29/2016	$	3,045.53
12/30/2016	$	3,049.91
12/31/2016	$	3,049.91
1/1/2017	$	3,045.38
1/2/2017	$	3,045.38
1/3/2017	$	3,045.38
1/4/2017	$	3,032.25
1/5/2017	$	3,033.71
1/6/2017	$	3,027.14
1/7/2017	$	3,030.79
1/8/2017	$	3,030.79
1/9/2017	$	3,030.79
1/10/2017	$	3,011.82
1/11/2017	$	3,019.85
1/12/2017	$	3,022.77
1/13/2017	$	3,029.33
1/14/2017	$	3,030.79
1/15/2017	$	3,030.79
1/16/2017	$	3,030.79
1/17/2017	$	3,030.79
1/18/2017	$	3,027.87
1/19/2017	$	3,022.04
1/20/2017	$	3,022.04
1/21/2017	$	3,018.39
1/22/2017	$	3,018.39
1/23/2017	$	3,018.39
1/24/2017	$	3,015.47
1/25/2017	$	3,022.77
1/26/2017	$	3,023.50
1/27/2017	$	3,034.44
1/28/2017	$	3,023.50
1/29/2017	$	3,023.50
1/30/2017	$	3,023.50
1/31/2017	$	3,019.12
2/1/2017	$	3,015.47

2/2/2017	$	3,015.47
2/3/2017	$	3,014.74
2/4/2017	$	3,007.44
2/5/2017	$	3,007.44
2/6/2017	$	3,007.44
2/7/2017	$	3,000.88
2/8/2017	$	3,008.90
2/9/2017	$	3,010.36
2/10/2017	$	3,014.01
2/11/2017	$	2,998.69
2/12/2017	$	2,998.69
2/13/2017	$	2,998.69
2/14/2017	$	3,001.61
2/15/2017	$	2,995.04
2/16/2017	$	3,001.61
2/17/2017	$	2,992.85
2/18/2017	$	2,981.91
2/19/2017	$	2,981.91
2/20/2017	$	2,981.91
2/21/2017	$	2,981.91
2/22/2017	$	2,965.13
2/23/2017	$	2,963.67
2/24/2017	$	2,972.42
2/25/2017	$	2,964.40
2/26/2017	$	2,964.40
2/27/2017	$	2,964.40
2/28/2017	$	2,965.13
3/1/2017	$	2,971.29
3/2/2017	$	2,976.40
3/3/2017	$	2,974.94
3/4/2017	$	2,972.02
3/5/2017	$	2,972.02
3/6/2017	$	2,972.02
3/7/2017	$	2,984.42
3/8/2017	$	2,979.31
3/9/2017	$	2,986.61
3/10/2017	$	2,998.29
3/11/2017	$	3,009.23
3/12/2017	$	2,998.29
3/13/2017	$	3,009.23
3/14/2017	$	3,016.53
3/15/2017	$	3,017.99
3/16/2017	$	3,014.34
3/17/2017	$	3,000.47
3/18/2017	$	2,997.56
3/19/2017	$	2,997.56
3/20/2017	$	2,997.56

3/21/2017	$	3,003.39
3/22/2017	$	3,013.61
3/23/2017	$	3,008.50
3/24/2017	$	3,000.47
3/25/2017	$	2,998.29
3/26/2017	$	2,998.29
3/27/2017	$	2,998.29
3/28/2017	$	3,008.50
3/29/2017	$	3,005.58
3/30/2017	$	3,011.42
3/31/2017	$	3,012.15
4/1/2017	$	3,011.73
4/2/2017	$	3,011.73
4/3/2017	$	3,011.73
4/4/2017	$	3,008.81
4/5/2017	$	3,015.38
4/6/2017	$	3,024.86
4/7/2017	$	3,024.86
4/8/2017	$	3,021.21
4/9/2017	$	3,021.21
4/10/2017	$	3,021.21
4/11/2017	$	3,019.75
4/12/2017	$	3,012.46
4/13/2017	$	3,013.19
4/14/2017	$	3,013.92
4/15/2017	$	3,013.92
4/16/2017	$	3,013.92
4/17/2017	$	3,013.92
4/18/2017	$	3,016.11
4/19/2017	$	3,012.46
4/20/2017	$	3,016.11
4/21/2017	$	3,012.46
4/22/2017	$	3,008.81
4/23/2017	$	3,008.81
4/24/2017	$	3,008.81
4/25/2017	$	3,004.43
4/26/2017	$	3,002.97
4/27/2017	$	3,005.16
4/28/2017	$	3,005.16
4/29/2017	$	3,013.92
4/30/2017	$	3,013.92
5/1/2017	$	3,003.35

#2

Federal Register Description of 18 C.F.R. 35.14 (Nov. 19, 1974)

the Code of Federal Regulations, are necessary and appropriate for the administration of the Federal Power Act.

(4) Good cause exists for making this order effective upon issuance.

The Commission, acting pursuant to the authority granted by the Federal Power Act, as amended, particularly section 309 (49 Stat. 858, 16 U.S.C. 825h), orders:

(A) The Commission's regulations Under the Federal Power Act prescribed by Subchapter B, Chapter I, Title 18 of the Code of Federal Regulations is amended by revising § 34.9 thereof. As so amended § 34.9 reads:

§ 34.9 Commission action.

(a) An application for approval under this part will ordinarily require a minimum of 30 days after it is filed to allow for public notice, investigation, opportunity for hearing, consideration by the Commission, and issuance of the first order referred to hereinafter. To facilitate the completion of registration statements filed with the Securities and Exchange Commission pursuant to the requirements of section 7 of the Securities Act of 1933 and sections 12 and 13 of the Securities and Exchange Act of 1934, so that public invitation for proposals for purchase or underwriting of the securities may be made, conformably to the provisions of those acts, this Commission will, where appropriate, authorize proposed issuance of securities and assumptions of obligation or liability, prior to the filing of the data referred to in §§ 34.1a(c) and 34.2(k) (3) and (4) subject to a provision that the securities shall not be issued, or the obligation or liability assumed, by the applicant, until such amendment shall have been filed and a further order shall have been entered thereon. The Commission will endeavor whereever possible to enter such further order upon receipt of telephone advice and confirmation thereof by telegram from the applicant setting forth the substance of the data specified in § 34.2(k) (3) and (4) and stating that the amendment furnishing such data has actually been mailed to the Commission. This two-order procedure will not obtain with respect to security issues exempted by § 34.1a (a) from competitive bidding requirements, except upon request, or where the first sentence of paragraph (b) of this section is applicable.

(b) If, pursuant to a public invitation, at least two independent proposals for the purchase or underwriting of the securities are received, the applicant may without further order of or filing with the Commission, issue or sell the securities in accordance with the terms and conditions contained in the application, (1) to the bidder or bidders offering to the company the lowest annual cost of money, or (2) in the case of common stock sold on a rights offering, to the bidder or bidders specifying the lowest aggregate amount of compensation to be paid by the issuer or (3) in the case of common stock sold on a straight sale and not on a rights offering, to the bidder or bidders specifying the highest total price to be paid to the company.

(c) Within 10 days after the consummation of any transaction pursuant to the provisions of paragraph (b) of this section, the applicant shall certify to the Commission that such transaction has been carried out in accordance with terms and conditions of and for the purposes represented by the applicant in his filing and of any order of the Commission with respect thereto. The applicant shall include as part of the certificate filed, the names of the purchasers or underwriters, the terms of the several proposals received, and the names of the persons submitting the proposals. Unless requested by the Commission to complete the record as to any other matter as to which jurisdiction has been specifically preserved, no further filing with respect to the issuance or sale of the securities shall be required.

(B) This order is effective upon issuance.

(C) The Secretary shall cause prompt publication of the order to be made in the FEDERAL REGISTER.

By direction of the Commission.

[SEAL] KENNETH F. PLUMB,
Secretary.

[FR Doc.74-26973 Filed 11-18-74;8:45 am]

[Docket Nos. R-479, 517]

PART 35—FILING OF RATE SCHEDULES

Fuel Cost Adjustment Clauses

NOVEMBER 13, 1974.

On June 21, 1973, notice of a proposed change in the regulations under the Federal Power Act was issued (38 FR 17253). Notice of a public conference, which was held on April 16, 1974, was issued on March 27, 1974 (39 FR 12171). On August 6, 1974, a renotice of a proposed change in the regulations was issued (39 FR 28910).

In the June 21 notice, we requested comments on alternative versions of the proposed amendment to the regulations. Comments were received from 43 investor-owned utilities, two law firms representing 9 investor-owned utilities, a group of 23 municipally-owned utilities, two state municipal groups, the Edison Electric Institute (EEI), the American Public Power Asociation (APPA), the National Coal Association, the commissions of the states of New York and Colorado, and the Environmental Protection Agency.[1] At the public conference, 21 investor-owned utilities, 23 municipally-owned utilities, APPA, the National Rural Electric Cooperative Association (NRECA), and the Maryland Public Service Commission were represented.[2] Additional written comments were received from one investor-owned utility and Representative Michael J. Harrington of Massachusetts. In response to the August 6, 1974 renotice of proposed rulemaking, which included only Alternatice 1 of the alternatives in the original notice, we received comments from 24 investor-owned utilities, 26 municipally-owned utilities, APPA, NRECA, the Maryland Council of Economic Advisors, and the Pennsylvania Public Utility Commission.

The principal objection to the proposed amendment to the regulations is the inclusion of nuclear fuel costs, in addition to fossil fuel costs, in the cost of fuel. Additionally, several utilities objected to the combining of fossil and nuclear fuel costs in the base and current cost of fuel rather than establishing separate base costs for each type of fuel. We do not believe that these objections are persuasive.

The basis for the objection to the inclusion of nuclear fuel costs is based on higher capital costs associated with the construction of nuclear plants. To include nuclear fuel costs in the fuel cost adjustment clause could result in lower total fuel costs during periods when the utilities are experiencing these higher capital costs. However, the purpose of this fuel cost adjustment clause is to keep the utilities whole with regard to changes in the fuel costs per Kwh sold. As was pointed out in the August 6 renotice of proposed rulemaking, Order No. 487[3] amended § 35.13 of the regulations to permit utilities to file estimated costs for a projected test year. We believe that the effect of any higher capital costs associated with the construction of nuclear generation should be reflected in the filing of a rate change and not in a fuel cost adjustment clause.

The reasons for including nuclear and fossil fuel costs in a single base cost rather than establishing separate base costs for each type of fuel is the same. We believe that a fuel cost adjustment clause should permit utilities to charge its customers for changes in the average fuel costs for each unit of energy sold.

Additional responses to the original notice of proposed rulemaking suggested that the cost of nuclear fuel should be that cost shown in Account 518 rather than the items shown in Account 120.1. We believe that this change is appropriate, and the change was made in the August 6, 1974 renotice and in the amendment hereinafter ordered, except that any fossil fuel costs reflected in Account 518 which are already included in the cost of fossil fuel shall be deducted from this account for the purposes of the fuel cost adjustment clause.

Certain responses suggested that the 500 account series be used for fossil fuel costs also. We believe that continued use of Account 151 for this expense is appropriate since the 500 series accounts include certain fuel handling expenses such

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[1] See Appendix A, filed as part of the original document, for a list of these parties.

[2] See Appendix B, filed as part of the original document, for a list of the parties who attended the conference.

[3] — FPC —, issued July 17, 1973.

as labor costs which do not vary in a manner similar to fuel costs and should not be included in a fuel cost adjustment clause.

The treatment of purchased power costs was commented on extensively in response to both notices and at the public conference. We have modified that amendment to the regulations to clarify the treatment of these costs and to cast the regulations in a form that would provide an incentive to the utilities to purchase energy, in other than conventional firm power transactions, when the total energy charge is less than the cost of the purchaser's own generation. This change will benefit consumers by permitting the purchaser to pass on the entire energy cost when it will replace the purchaser's higher cost energy, thus reducing the costs to the consumer. However, in these transactions, we are permitting the inclusion of only the charge for energy and not other charges which are associated with capital costs or other costs that are unrelated to the cost of fuel consumed.

In response to written comments and oral comments at the public conference on the proposed rulemaking, that part of the proposed regulation relating to company-owned or controlled sources of fuel was modified. The modification provided that when a utility purchases fuel from an owned or controlled source and the price is subject to the jurisdiction of a regulatory body, the cost of the fuel may be included in the fuel adjustment clause. However, if the price is not subject to the jurisdiction of a regulatory body, the utility must file the contract and amendments thereto with the Commission at the time the company's fuel clause or amendment to its fuel clause is filed. Subsequent modifications of the fuel contract are likewise to be filed as a change in rate schedules under section 205 of the Federal Power Act. We believe that this provision is necessary to insure the reasonableness of fuel costs from company-owned or controlled sources.

Certain comments suggested that costs associated with pollution control facilities and processes be included in the fuel adjustment clause. We do not believe that these costs are appropriate for inclusion in the fuel cost adjustment clause. We believe that the future test year concept adequately provides for any costs which will be associated with pollution control equipment and the rates can be designed to recover these costs.

Other comments suggest that utilities be permitted to recover only a portion of increased fuel costs in order to provide an incentive to bargain for lower cost fuel. It should be noted that to the extent that only a portion of changes in fuel costs are permitted to be reflected in rates, the purpose of the fuel clause (namely to pass on to customers the increases or decreases in the fuel costs actually incurred by the utility) is to that extent defeated. When fuel costs are rising, the utility is disadvantaged by not being able to collect the full amount of the increase; when fuel costs are falling the customers are disadvantaged because the full amount of the reductions are not passed along, but are partly retained by the utility. In addition, the lag in collections for fuel expenses inherent in a typical fuel cost adjustment clause provides some incentive for companies to bargain for favorable prices during periods of rising fuel costs.

Several utilities suggested that the fuel cost adjustment clause should be modified so that the utility may recover local and state gross receipts for revenue based taxes on increased revenues produced by the operation of a fuel cost adjustment clause. Although the current regulation is silent with respect to recovery of such taxes, we have in the past accepted fuel adjustment clauses with provisions for recovery of these taxes. We believe that recovery of these taxes in the fuel adjustment clause is consistent with the purpose of a fuel adjustment clause—to make utilities whole for increased costs associated with changes in fuel costs. We have therefore added an explicit provision to permit recovery of these taxes.

Additional comments urged that the proposed regulation be implemented immediately. We have added a provision that all rate filings which contain a new or changed fuel clause shall conform these clauses with the regulations. We believe that, with the addition of nuclear fuel costs to the fuel adjustment clause, and in light of rapidly rising fossil fuel costs, our purpose of protection of the consumers while keeping utilities whole for increases in fuel costs dictates that rate filings with a new or changed fuel clause conform to the new regulation. We also believe that two years to conform to the amended regulation is excessive and not in the public interest. We have, therefore, altered the previously proposed provision that rate schedules currently filed with the Commission be conformed to the regulation within two years of the adoption of this rulemaking. Instead, we have provided that rate schedules currently filed with the Commission be conformed to the amended regulation within one year of the effectiveness of this rulemaking. We recognize that special circumstances and operating characteristics may warrant a temporary delay in the implementation of this regulation. Since we have retained the provision that, for good cause shown, waiver of the requirements of this section of the regulations may be granted for an additional one year period, we believe that no utility will be prejudiced by the shortened time for conformity, while conformity will be reached in an orderly fashion within a reasonable time.

We believe that any changes we have made are minor and are entirely consistent with our intentions as stated in the notice of proposed rulemaking issued June 21, 1973, and in the renotice issued August 6, 1974.

In order to permit the utilities to conform any new rate filings to the new regulation, we shall make the new § 35.14 of the regulations effective for all rate changes or initial rates filed on or after January 1, 1975.

The Commission finds:

(1) The notice and opportunity to participate in this rulemaking with respect to matters presently before this Commission through the submission, orally and in writing of data, views, comments, and suggestions are consistent and in accordance with the procedural requirements prescribed by 5 U.S.C. 553.

(2) The amendment to § 35.14 in Chapter I, Title 18 of the Code of Federal Regulations, herein prescribed, is necessary and appropriate for the administration of the Federal Power Act.

(3) Since those parts of the amendment prescribed herein that were not included in the notices issued in this proceeding are of a minor nature and are consistent with the principal purpose of the proposed rulemaking, further compliance with the notice requirements of 5 U.S.C. 553.

(4) Since the amendment prescribed herein affect all new rate filings with a new or changed fuel clause, good cause exists to make the amendment effective for all initial rates or rate changes filed on or after January 1, 1975.

The Commission, acting pursuant to the authority of the Federal Power Act, as amended, particularly sections 205, 206 and 309 (16 U.S.C. 824, 825) orders:

(A) Section 35.14 of the regulations under the Federal Power Act (Title 18 Part I, Subchapter B of the Code of Federal Regulations) is hereby amended, effective January 1, 1975, by deleting all of the present regulations except paragraph (a) and adding the following:

§ 35.14 Fuel cost adjustment clauses.

(a) * * *

(1) The fuel clause shall be of the form that provides for periodic adjustments per kWh of sales equal to the difference between the fuel cost per kWh of sales in the base period and in the current period:

$$\text{Adjustment Factor} = \frac{Fm}{Sm} - \frac{Fb}{Sb}$$

Where: "F" is the expense of fossil and nuclear fuel in the base (b) and current (m) periods; and "S" is the kWh sales in the base and current periods, all as defined below.

(2) Fuel costs (F) shall be the cost of:

(i) Fossil and nuclear fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants.

(ii) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (a)(2)(iii) below.

(iii) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less

(iv) The cost of fossil and nuclear fuel recovered through inter-system sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(3) Sales (S) shall be all kWh's sold, excluding inter-system sales. Where for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to the sum of (i) generation, (ii) purchases, (iii) interchange-in, less (iv) energy associated with pumped storage operations, less (v) inter-system sales referred to in paragraph (a)(2)(iv) above, less (vi) total system losses.

(4) The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

(5) The adjustment factor developed according to this procedure may be further modified to allow the recovery of gross receipts and other similar revenue based tax charges occasioned by the fuel adjustment revenues.

(6) The cost of fossil fuel shall include no items other than those listed in Account 151 of the Commission's Uniform System of Accounts for Public Utilities and Licensees. The cost of nuclear fuel shall be that as shown in Account 518, except that if Account 518 also contains any expense for fossil fuel which has already been included in the cost of fossil fuel, it shall be deducted from this account. (Paragraph C of Account 518 includes the cost of other fuels used for ancillary steam facilities.)

(7) Where the cost of fuel includes fuel from company-owned or controlled [1] sources, that fact shall be noted and described as part of any filing. Where the utility purchases fuel from a company-owned or controlled source, the price of which is subject to the jurisdiction of a regulatory body, such cost shall be deemed to be reasonable and includable in the adjustment clause. If the current price, however, is in litigation and is being collected subject to refund, the utility shall so advise the Commission and shall keep a separate account of such amounts paid which are subject to refund, and shall advise the Commission of the final disposition of such matter by the regulatory body having jurisdiction. With respect to the price of fuel purchases from company-owned or controlled sources pursuant to contracts which are not subject to regulatory authority, the utility company shall file such contracts and amendments thereto with the Commission for its acceptance at the time it files its fuel clause or modification thereof. Any subsequent amendment to such contracts shall likewise be filed with the Commission as a rate schedule change and may be subject to suspension under section 205 of the Federal Power Act. Fuel charges by affiliated companies which do not appear to be reasonable may result in the suspension of the fuel adjustment clause or cause an investigation thereof to be made by the Commission on its own motion under section 206 of the Federal Power Act.

(8) All rate filings which contain a proposed new fuel clause or a change in an existing fuel clause shall conform such clauses with the regulations. Within one year of the effectiveness of this rulemaking, all public utilities with rate schedules that contain a fuel clause should conform such clauses with the regulations. Recognizing that individual public utilities may have special operating characteristics that may warrant granting temporary delays in the implementation of the regulations, the Commission may, upon showing of good cause, waive the requirements of this section of the regulations for an additional one-year period so as to permit the public utilities sufficient time to adjust to the requirements.

(9) All rate filings containing a proposed new fuel clause or change in an existing fuel clause shall include:

(i) A description of the fuel clause with detailed cost support for the base cost of fuel;

(ii) Full cost of service data unless the utility has had the rate approved by the Commission within a year, provided that such cost of service may not be required when an existing fuel cost adjustment clause is being modified to conform to the Commission's regulations.

(10) Whenever particular circumstances prevent the use of the standards provided for herein, or the use thereof would result in an undue burden, the Commission may, upon application under § 1.7(b) of the rules of practice and procedure and for good cause shown, permit deviation from these regulations.

(B) Any new rate filing tendered before the effectiveness of the new regulation may include a fuel cost adjustment clause that conforms to the new regulation.

(C) The Secretary shall cause prompt publication of this order in the FEDERAL REGISTER.

By the Commission.

[SEAL] KENNETH F. PLUMB, *Secretary.*

[FR Doc.74-26972 Filed 11-18-74;8:45 am]

[1] As defined in the Commission's Uniform System of Accounts 18 CFR Part 101, Definitions 5B.

Title 28—Judicial Administration

CHAPTER I—DEPARTMENT OF JUSTICE

[Directive 74-3]

PART 0—ORGANIZATION OF THE DEPARTMENT OF JUSTICE

Appendix to Subpart R—Redelegation of Functions

Under the authority delegated to the Administrator by §§ 0.100 and 0.104 of Subpart R, I hereby make the following change in Directive 73-1, 38 FR 18381.

Section 3(c) is amended by changing the period at the end thereof to a semicolon and adding the following:

Sec. 3 Enforcement officers.

* * * * *

(c) * * *; and to adjust, determine, compromise and settle any claim involving the Drug Enforcement Administration under 28 U.S.C. 2672 relating to tort claims where the claim is for property damages not exceeding $250.

Dated: November 12, 1974.

JOHN R. BARTELS, Jr., *Administrator, Drug Enforcement Administration.*

[FR Doc.74-27004 Filed 11-18-74;8:45 am]

Title 40—Protection of Environment

CHAPTER I—ENVIRONMENTAL PROTECTION AGENCY

SUBCHAPTER E—PESTICIDE PROGRAMS

[FRL 282-3]

PART 180—TOLERANCES AND EXEMPTIONS FROM TOLERANCES FOR PESTICIDE CHEMICALS IN OR ON RAW AGRICULTURAL COMMODITIES

Certain Inert Ingredients in Pesticide Formulations

Correction

In FR Doc. 74-23945, appearing in the issue of Monday, October 21, 1974, on page 37378, the fifth line in table (e) on page 37379 should read

"Manganous oxide ---- Solid diluent, carrier."

Title 41—Public Contracts and Property Management

CHAPTER 9—ATOMIC ENERGY COMMISSION

PART 9-5—SPECIAL AND DIRECTED SOURCES OF SUPPLY

Alcohol; Miscellaneous Amendment

This revision to AECPR 9-5.5204 is being made to reflect current title of the Bureau of Alcohol, Tobacco and Firearms.

In Subpart 9-5.52, Procurement of Special Items, §§ 9-5.5204 through 9-5.5204-10 are revised as follows:

Subpart 9-5.52—Procurement of Special Items

Sec.
9-5.5204 Alcohol.
9-5.5204-1 Scope.
9-5.5204-2 Regulations.
9-5.5204-3 Application forms and permits
9-5.5204-4 Authority to sign applications
9-5.5204-5 Filing applications.
9-5.5204-6 Forms and authorized plants.
9-5.5204-7 Placing the order.
9-5.5204-8 Notice of shipment.
9-5.5204-9 Orders placed by cost-type contractors.
9-5.5204-10 Abandoned and forfeited alcohol.

* * * * *

§ 9-5.5204 Alcohol.

§ 9-5.5204-1 Scope.

This section covers (a) Bureau of Alcohol, Tobacco and Firearms, Treasury Department, alcohol regulations applicable to AEC, (b) delegations of authority to submit applications to purchase tax-free alcohol or specially denatured alcohol, and (c) purchases of alcohol by AEC or cost-type contractors.

#3

KIUC Ex. 1

807 KAR 5:056. Fuel adjustment clause.

RELATES TO: KRS 61.870 - 61.884, 143.020, Chapter 278
STATUTORY AUTHORITY: KRS 278.030(1), (2), 278.040(3)
NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.040(3) authorizes the Public Service Commission to promulgate administrative regulations to implement the provisions of KRS Chapter 278. KRS 278.030(1) authorizes utilities to demand, collect, and receive fair, just, and reasonable rates. KRS 278.030(2) requires every utility to furnish adequate, efficient, and reasonable service. This administrative regulation establishes the requirements with respect to the implementation of automatic fuel adjustment clauses by which electric utilities may immediately recover increases in fuel costs subjected to later scrutiny by the Public Service Commission.

Section 1. Fuel Adjustment Clause. Fuel adjustment clauses that are not in conformity with the requirements established in subsections (1) through (6) of this section are not in the public interest and may result in suspension of those parts of the rate schedules based on severity of the nonconformity and any history of nonconformity.

(1) The fuel adjustment clause shall provide for periodic adjustment per Kilowatt Hour (KWH) of sales equal to the difference between the fuel costs per KWH sale in the base period and in the current period according to the following formula:

$$Adjustment\ Factor = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F(b) is the cost of fuel in the base period, F(m) is the cost of fuel in the current period, S(b) is sales in the base period, and S(m) is sales in the current period, all as established in subsections (2) through (6) of this section.

(2) F(b)/S(b) shall be determined so that on the effective date of the commission's approval of the utility's application of the formula, the resultant adjustment shall be equal to zero.

(3) Fuel costs (F) shall be the most recent actual monthly cost, based on weighted average inventory costing, of:

(a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel that would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than as established in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges irrespective of the designation assigned to the transaction, if the energy is purchased on an economic dispatch basis. Costs, such as the charges for economy energy purchases, the charges as a result of scheduled outage, and other charges for energy being purchased by the buyer to substitute for the buyer's own higher cost energy, may be included; and less

(d) The cost of fossil fuel recovered through intersystem sales, including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(4) Forced outages are all nonscheduled losses of generation or transmission that require substitute power for a continuous period in excess of six (6) hours. If forced outages are

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not the result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the utility may, upon proper showing, with the approval of the commission, include the fuel cost of substitute energy in the adjustment. In making the calculations of fuel cost (F) in subsection (3)(a) and (b) of this section, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation until approval is obtained.

(5) Sales (S) shall be all KWH's sold, excluding intersystem sales. Utility used energy shall not be excluded in the determination of sales (S). If, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to:

(a) Generation; plus
(b) Purchases; plus
(c) Interchange-in; less
(d) Energy associated with pumped storage operations; less
(e) Intersystem sales referred to in subsection (3)(d) of this section; less
(f) Total system losses.

(6) The cost of fossil fuel shall only include the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees, less any cash or other discounts.

Section 2. Filing Requirements.

(1) If a utility initially proposes a fuel adjustment clause, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the commission and all other agreements, options, amendments, modifications, and similar documents related to the procurement of fuel supply or purchased power.

(2) Any changes in the contracts or other documents filed pursuant to subsection (1) of this section, including price escalations, and any new agreements entered into after the initial submission, shall be submitted at the time they are entered into.

(3) If fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted, and the utility shall explain and justify them in writing.

(4) The monthly fuel adjustment shall be filed with the commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment.

(5) Copies of all documents required to be filed with the commission under this administrative regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 through 61.884.

Section 3. Review of Fuel Adjustment Clauses.

(1) Fuel charges that are unreasonable shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges.

(2) The commission on its own motion may investigate any aspect of fuel purchasing activities covered by this administrative regulation.

(3)

(a) At six (6) month intervals, the commission shall conduct a formal review and may conduct public hearings on a utility's past fuel adjustments.

(b) The commission shall order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments the commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.

(4)

(a) Every two (2) years following the initial effective date of each utility's fuel clause, the commission shall conduct a formal review and evaluate past operations of the clause, disallow improper expenses and, to the extent appropriate, reestablish the fuel clause charge in accordance with Section 1(2) of this administrative regulation.

(b) The commission may conduct a public hearing if the commission finds that a hearing is necessary for the protection of a substantial interest or is in the public interest.

(8 Ky.R. 822; eff. 4-7-1982; Crt eff. 3-27-2019; 45 Ky.R. 3272; 46 Ky.R. 41, 435; eff. 8-20-2019; 47 Ky.R.1485, 1965; eff. 6-3-2021.)

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN EXAMINATION BY THE PUBLIC SERVICE COMMISSION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF AMERICAN ELECTRIC POWER COMPANY FROM MAY 1, 2001 TO OCTOBER 31, 2001	)))))	CASE NO. 2000-00495-B

ORDER

Pursuant to Administrative Regulation 807 KAR 5:056, the Commission on December 20, 2001 established this case to review and evaluate the operation of the fuel adjustment clause (FAC) of American Electric Power Company (AEP) for the 6 months ended October 31, 2001.

As part of this review, AEP, pursuant to Commission Order, submitted certain information concerning its compliance with Administrative Regulation 807 KAR 5:056. A public hearing was held on February 19, 2002 at which the following persons testified: Errol Wagner, AEP s Director of Rates; Todd William Alleshouse, Energy Production Manager of AEP s Big Sandy Generating Plant; and Steven D. Baker, AEP s Manager of Case Management.

The Commission previously established AEP s base fuel cost at 11.45 mills per Kwh.[1] A review of AEP s monthly fuel clause filings shows that the actual fuel cost incurred for the 6-month period under review ranged from a low of 10.16 mills in May 2001 to a high of 13.07 mills in October 2001, with a 6-month average of 11.10 mills.

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[1] Case No. 2000-495, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of American Electric Power Company from November 1, 1998 to October 31, 2000 (March 15, 2001).

During this proceeding, the Commission examined the appropriate treatment under Administrative Regulation 807 KAR 5:056 for purchased power costs incurred to serve native load.[2] More specifically, we inquired about the types of power purchases that qualify as economy power purchases and the treatment of power purchases that are not considered economy power purchases.

Administrative Regulation 807 KAR 5:056, Section 1(3),[3] governs the recovery of purchased energy costs through an electric utility s FAC. It permits the inclusion of economy energy purchases, exclusive of capacity or demand charges, in the cost of fuel as calculated for FAC purposes when such energy is purchased on an economic dispatch basis. It also permits the recovery of actual identifiable fossil and nuclear fuel costs associated with energy purchased in non-economy transactions.

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2 See Transcript at 28-31.

3 Fuel costs (F) shall be the most recent actual monthly cost of:

> (a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel which would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus
>
> (b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than identified in paragraph (c) of this subsection, but excluding the cost of fuel related to purchases to substitute for the forced outages; plus
>
> (c) The net energy cost of energy purchases, exclusive of capacity or demand charges (irrespective of the designation assigned to such transaction) when such energy is purchased on an economic dispatch basis. Included therein may be such costs as the charges for economy energy purchases and the charges as a result of scheduled outage, all such kinds of energy being purchased by the buyer to substitute for its own higher cost energy; and less
>
> (d) The cost of fossil fuel recovered through intersystem sales including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.
>
> (e) All fuel costs shall be based on weighted average inventory costing.

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In a highly regulated electric power wholesale market in which power suppliers routinely identified on their billing statements the portions of energy purchases attributable to fuel cost and to demand or capacity charges, this regulation was relatively easy to administer. With the recent restructuring of the wholesale electric power market, however, few wholesale suppliers continue to engage in such billing practices. AEP reports that none of its wholesale power suppliers provide this information.[4] To comply with the requirements of Administrative Regulation 807 KAR 5:056, it uses historical pricing information and reports the fuel cost of its power purchases as 80 percent of total purchase price.[5]

The Commission is concerned that these new market conditions, when coupled with the increasing use of purchased power to meet native load requirements, will lead to disparate treatment of purchased energy costs. Some electric utilities are treating energy purchases that supplement, but do not displace native generation, as economy purchases and seeking recovery of the total purchase cost through their FACs. Some electric utilities, no longer receiving billing information that identifies the fuel portion of their non-economy power purchases, are treating the entire purchase as a fuel cost. Other electric utilities, also lacking detailed billing information, are attempting to estimate the cost of the fuel portion of such transactions based on historic billing information. As a result, uniform treatment of fuel costs is being eroded creating the potential for recovery of non-fuel related costs through FACs.

Based upon our review of Administrative Regulation 807 KAR 5:056 and in recognition of the recent changes in the wholesale energy market, we find that some

[4] AEP Response to the Commission s Order of December 20, 2001, Item 22(a).

[5] AEP Response to the Commission s Order of December 20, 2001, Item 22(b).

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clarification of the regulation s treatment of economy energy purchases and non-economy energy purchases is necessary. Economy energy is [e]nergy produced and supplied from a more economical source in one system, substituted for that being produced or capable of being produced by a less economical source in another system." Sierra Pacific Power Co. v. Public Service Commission of Nevada, 634 P.2d 1200, 1203 fn.1 (Nev. 1981). Economy energy sales occur when utilities purchase energy from other utilities that can generate the energy at lower cost. Citizens of State v. Public Service Com'n, 464 So.2d 1194 (Fla.1985).[6]

We view economy energy purchases that are recoverable through an electric utility s FAC as purchases that an electric utility makes to serve native load, that displace its higher cost of generation, and that have an energy cost less than the avoided variable generation cost of the utility s highest cost generating unit available to serve native load during that FAC expense month. When the purchased energy price consists of a total charge per unit of energy, with no separate demand charge, the energy cost is the total charge per unit of energy. Where an energy vendor lists the components of the total energy price, the energy cost is the energy cost exclusive of any demand or capacity charges.

Non-economy energy purchases are purchases made to serve native load that have an energy cost greater than the avoided variable cost of the utility s highest cost generating unit available to serve native load during that FAC expense month. When the purchased energy price of such purchases consists of a total charge per unit of energy, with no separate demand charge, the energy cost is the total charge per unit

[6] Such transactions are generally considered beneficial to utility ratepayers by permitting purchasing utilities to obtain lower cost power to meet their native load requirements while allowing selling utilities the opportunity to earn additional revenue by the sale of excess power.

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of energy. When an energy vendor lists the components of the total energy price, the energy cost is the energy cost exclusive of any demand or capacity charges.

We interpret Administrative Regulation 807 KAR 5:056 as permitting an electric utility to recover through its FAC only the lower of the actual energy cost of the non-economy purchased energy or the fuel cost of its highest cost generating unit available to be dispatched to serve native load during the reporting expense month. Costs for non-economy energy purchases that are not recoverable through an electric utility s FAC are considered non-FAC expenses and, if reasonably incurred, are otherwise eligible for recovery through base rates.

The Commission believes that this interpretation is consistent with the letter and the spirit of Administrative Regulation 807 KAR 5:056. It should ensure a uniform treatment of fuel costs by all electric utilities subject to our jurisdiction, provide a greater degree of certainty as to the fuel expenses eligible for recovery through a FAC, and encourage reasonable and economically efficient energy procurement practices, while continuing to protect the interests of utility ratepayers. We place AEP on notice that this interpretation shall be applied to all energy purchases made after April 30, 2002.

In reaching our interpretation, we are mindful that some power purchases occur under emergency circumstances. We recognize that in such circumstances wholesale power market prices may significantly exceed the fuel cost of an electric utility s highest cost generating unit available to serve native load. In those circumstances, the utility may apply to the Commission for immediate rate recovery of those costs. In reviewing such applications, we will carefully consider, inter alia, the nature of the emergency, the reasonableness of the energy transactions, the effect of non-recovery upon the utility, and all reasonable and lawful means of rate recovery available to the utility.

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The Commission, having considered the evidence of record and being otherwise sufficiently advised, finds no evidence of improper calculation or application of AEP s FAC charges or improper fuel procurement practices.

IT IS THEREFORE ORDERED that the charges and credits billed by AEP through its FAC for the period May 1, 2001 to October 31, 2001 are approved.

Done at Frankfort, Kentucky, this 2nd day of May, 2002.

By the Commission

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN EXAMINATION BY THE PUBLIC SERVICE COMMISSION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF AMERICAN ELECTRIC POWER COMPANY FROM MAY 1, 2001 TO OCTOBER 31, 2001	))))))	CASE NO. 2000-00495-B

O R D E R

On May 2, 2002, the Commission approved the fuel charges and credits that American Electric Power (AEP) billed through its Fuel Adjustment Clause (FAC) for from May 1, 2001 to October 31, 2001. In the same Order in which we approved those charges, we set forth our interpretation of Administrative Regulation 807 KAR 5:056 as it pertains to the recovery of non-economy purchased energy costs. More specifically, we declared that Administrative Regulation 807 KAR 5:056 permits an electric utility to recover through its FAC only the lower of the actual energy cost of the non-economy purchased energy or the fuel cost of its highest cost generating unit available to be dispatched to serve native load during the reporting expense month.[1] We further placed AEP on notice that we would apply this interpretation to all energy purchases occurring after April 30, 2002.

AEP, unlike the other electric utilities in this state that generate electricity, operates as part of a multi-state system that relies solely on low-cost base load

[1] Case No. 2000-00495-B, An Examination by the Public Service Commission of the Application of the Fuel Adjustment Clause of American Electric Power Company from May 1, 2001 to October 31, 2001(Ky.PSC May 2, 2002) at 5.

generating units rather than a mix of generating units that includes higher cost peaking units. Expressing its concern that our interpretation failed to consider AEP s unique operating characteristics and would not achieve the Commission s expressed goal of uniform treatment of fuel costs, AEP petitioned for rehearing of our Order of May 2, 2002. On June 11, 2002, we granted AEP s petition.

AEP proposes the use of a proxy mechanism for the energy portion of non-economy energy purchases. Under this proposal, AEP recovers through its FAC non-economy purchased power costs that are the lower of its actual purchased power cost and the peaking unit equivalent cost.[2] AEP s proxy mechanism is based upon the operating characteristics of a General Electric simple cycle gas turbine.[3] The cost of the gas used by this hypothetical turbine will be the sum of the daily midpoint price for Columbia Gas Transmission (delivered Citygate) as published in that day s edition of Platt s Gas Daily and the current tariff rate for Columbia s Park and Lend Rate.

When a power purchase occurs during an expense month, AEP will determine the average daily market price for that month. It will then determine the lowest daily market price for gas for the hypothetical turbine during that month and compare that price to its actual average purchased energy cost for internal uses for the same month.

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[2] AEP presented its proposal at an informal conference on June 20, 2002 and subsequently submitted a written explanation of its proposal to Commission Staff and Kentucky Industrial Utility Customers, Inc. No objections to the proposal have been filed with the Commission. For further description of the mechanism, see Letters from Errol Wagner, AEP Director of Regulatory Services, to Gerald Wuetcher, Assistant General Counsel, Public Service Commission (June 28, 2002 and Aug. 12, 2002).

[3] A General Electric simple cycle gas turbine has a heat rate of 10,400 Btu/kWh at 50° Fahrenheit (winter operation) and a heat rate of 10,800 Btu/kWh at 90° Fahrenheit (summer operation). AEP proposes to use the heat rate of 10,400 Btu/kWh for the months of September through May and the heat rate of 10,800 for the months of 10,800 Btu/kWh for the months June through August.

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If the actual average purchased energy cost for internal use for the month is 75 percent or less of the lowest daily market price for gas for the hypothetical gas turbine during the same month, AEP will consider this cost as the fuel cost for these purchases. If the actual average purchased energy cost for internal use for the month is greater than 75 percent of the lowest daily market price for gas for the hypothetical gas turbine, then AEP will compare its average purchased energy cost for internal uses with the market price for gas for the hypothetical turbine for each day of the month and exclude for FAC purposes any of the actual purchased energy costs that exceed the daily gas market price.

The Commission recognizes AEP is unique among Kentucky generators as it operates only base load coal-fired units. Our interpretation of Administrative Regulation 807 KAR 5:056, as set forth in our Order of May 2, 2002, permits AEP to recover a lesser portion of the cost of purchased power than other utilities that operate higher cost gas-fired peaking generators. This result could occur even if the supplier and source of supply are the same. This anomaly requires us to consider the use of AEP s proposed proxy mechanism. Based upon our review of the record and being otherwise sufficiently advised, we find that AEP s proposed Peaking Unit Equivalent approach to calculate the level of non-economy purchased power costs to flow through its FAC is reasonable and should be approved.

IT IS THEREFORE ORDERED that:

1. AEP shall use the Peaking Unit Equivalent approach to calculate the level of non-economy purchased power costs to flow through its FAC.

2. AEP shall use the Peaking Unit Equivalent method to calculate the level of non-economy purchased power costs to flow through its FAC on non-economy power purchases made after September 30, 2002.

Done at Frankfort, Kentucky, this 3rd day of October, 2002.

By the Commission

ATTEST:

Executive Director

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))))	CASE NO. 2017-00179

ORDER

Kentucky Power Company ("Kentucky Power"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP") is an electric utility that generates, transmits, distributes, and sells electricity to approximately 168,000 consumers in all or portions of 20 counties in eastern Kentucky.[1] Kentucky Power owns and operates a 285-megawatt ("MW") gas-fired steam-electric generating unit in Louisa, Kentucky, and owns and operates a 50 percent undivided interest in a coal-fired generating station in Moundsville, West Virginia; Kentucky Power's share consists of 780 MW. Kentucky Power obtains an additional 393 MW from Rockport (Indiana) Plant Generating Units No. 1 and No. 2 under a unit power agreement ("Rockport UPA"). Kentucky Power's transmission system is operated by PJM Interconnection, LLC ("PJM"), a regional

[1] Application at 2. Kentucky Power also furnishes electric service at wholesale to the Cities of Olive Hill and Vanceburg, Kentucky.

The Commission is not convinced that this issue requires special ratemaking treatment. The Commission has long held that any purchased power costs not recoverable through the FAC are eligible for recovery through base rates. The Commission finds Kentucky Power's proposal to include an estimated amount of FAC Purchased Power Limitation Expense in base rates, and to subsequently true up that amount through Tariff P.P.A., is unreasonable, and therefore should be denied. The Commission notes that Kentucky Power filed this case using a historic test period. The Commission will allow recovery of the test year amount of purchased power reasonably incurred, but excluded from the FAC. To the extent that Kentucky Power incurs any expense due to purchased power that is appropriately incurred after the test year, but excluded from the FAC, it can file a base rate case seeking recovery of those expenses. For the foregoing reasons, adjustments W26 and W27, which total $4,032,786, are unreasonable and should be removed from the revenue requirement.

3. Peaking Unit Equivalent Calculation

Kentucky Power proposed to change the methodology for calculating the peaking unit equivalent ("PUE") used in determining the FAC Purchased Power Limitation. In its Application, Kentucky Power proposes to include the cost of firm gas service as an expense in the calculation of its PUE. Kentucky Power stated that since the hypothetical combustion turbine ("CT") could be dispatched any day of the year, it requires firm gas service. The Commission disagrees. While firm gas service would certainly allow the CT to be dispatched any day of the year, the Commission is unaware of any jurisdictional utility utilizing firm gas service for a CT. Because CTs typically operate at low capacity factors and are primarily utilized during the summer peaking months, when pipeline capacity would typically not be constrained, the Commission finds the inclusion of firm gas service in the calculation of the PUE to be unreasonable, and therefore, this change in the PUE calculation should be denied. Kentucky Power's proposal to include startup costs and variable O&M expense is reasonable and should be approved.

4. Gains and Losses from Incidental Gas Sales.

Kentucky Power proposed to recover gains and losses from incidental sales of natural gas through Tariff P.P.A. Kentucky Power nominates Big Sandy Unit 1 in the PJM day-ahead electric power market based in part on the price of natural gas purchased for delivery the next day. If the Big Sandy Unit 1 Day Ahead nomination price is higher than the PJM electric power market clearing price, Big Sandy Unit 1 is not selected to run in the Real Time Market. In such a case, the natural gas purchased must either be stored by Columbia Gas or be sold. Kentucky Power stated that in August, September, and November of 2016, there were days that it was required to sell natural gas that had been purchased for delivery because Big Sandy Unit 1 was not selected by PJM to run.[140]

In Case No. 2014-00078, Duke Energy Kentucky ("Duke Energy") proposed similar treatment of gains and losses it experienced in January and February of 2014 from incidental sales of natural gas.[141] Duke Energy amended its request to apply to similar losses or gains occurring in the future. The Commission approved the treatment of the January and February 2014 gains and losses. However, the Commission found

[140] Application, Direct Testimony of John A. Rogness at 26-27

[141] Case No. 2014-00078, *An Investigation of Duke Energy Kentucky, Inc.'s Accounting Sale of Natural Gas Not Used in Its Combustion Turbines* (Ky. PSC Nov. 25, 2014).

Q. HAS THE COMPANY PROPOSED THIS TYPE OF RECOVERY IN PREVIOUS PROCEEDINGS FOR THE FAC PURCHASE POWER LIMITATION EXPENSE?

A. Yes, in Case No. 2014-00396, the Company proposed to collect all FAC Purchase Power Limitation expense through Tariff PPA. In its final order in that proceeding the Commission denied this recovery and stated the following:

> *"Kentucky Power has not shown that the amounts of these excluded purchased power costs are volatile to the point of requiring this method of recovery. In addition, the Commission notes that there would be numerous administrative issues involved in establishing periodic proceedings to review and approve or deny these costs. The Commission believes these costs are more appropriately recoverable through base rates and will not approve this portion of the Settlement."*

The Company's proposal in this case conforms to the Commission's guidance on this issue in past cases. The Company's proposal to include an adjusted level of purchase power limitation expense in its base rate cost of service and track the differences between that level and the volatile, actual expense is reasonable and equitable to both customers and the Company. Moreover, this method does not add any significant administrative burden as it is similar to other tracking mechanisms utilized the by the Company. If this expense item is not tracked through the purchase power adjustment, the Company stands to profit from or lose on an item that should be a dollar for dollar pass-through to customers as a cost of serving them, due to the extreme volatility and materiality of the FAC Purchase Power Limitation expense.

Q. IS THE COMPANY PROPOSING ANY CHANGE TO THE CALCULATION OF THE FAC PURCHASED POWER LIMITATION?

A. Yes. The Company is proposing to change the methodology for calculating the cost of the peaking unit equivalent used in the determining the FAC Purchased Power

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Limitation. The Company's proposed change results in a peaking unit equivalent cost that more accurately reflects the cost of a hypothetical combustion turbine.

Q. PLEASE DESCRIBE HOW THE COST OF THE PEAKING UNIT EQUIVALENT IS CALCULATED.

A. Currently, the cost of the peaking unit equivalent is calculated solely by multiplying the lowest hourly daily gas price at the Columbia Gas Appalachian pricing point (in $/MMBtu) by a 10,400 heat rate (10,800 for June – August), divided by 1,000). For example, a gas price of $3/MMBtu results in a peaking unit equivalent cost of $31.2/MWh [(3*10,400)/1000 = 31.2]. If the peaking unit equivalent is the highest cost unit in that hour[10], the FAC Purchased Power Limitation limits recovery of purchased power costs through the FAC to $31.2/MWh. To the extent the expense arising from this operation of the FAC Purchased Power Limitation, which is controlled by factors outside the Company's control, is not included in base rates, the Company is forced to absorb the expense.

Q. WHAT CHANGES TO THE PEAKING UNIT EQUIVALENT CALCULATION IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company proposes to include the following operating costs in calculation of the cost of the peaking unit equivalent:

- Unit startup costs
- The cost of firm natural gas service
- Variable O&M expense

[10] The hourly peaking unit equivalent cost calculation compares the hypothetical peaking unit to the Company's other generating units and uses the highest cost unit for the FAC Purchased Power Limitation calculation. The hypothetical peaking unit is often the highest cost unit.

Q. WHY SHOULD THESE COSTS BE INCLUDED IN THE PEAKING UNIT EQUIVALENT COST CALCULATION?

A. All of these costs the Company is proposing to include are costs that would be incurred to operate an actual natural gas combustion turbine generating unit (CT). The peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT because the Company does not own a real CT for the purposes of calculating the FAC Purchased Power Limitation.

CT startup costs include start up fuel consumed, station power requirements and start up maintenance and labor; and are incurred when bringing a CT online but prior to the unit generating power. These are real costs that the hypothetical CT would incur in order to generate electricity and should be included in the peaking unit equivalent cost calculation.

In order to be available to generate electricity, a CT needs to have access to natural gas which is contracted for on either a non-firm or firm basis. Firm gas service means that the unit has reserved a portion of the capacity in the pipeline making gas always available for use in generating electricity. Since the hypothetical CT used in the peaking unit equivalent cost calculation can be "dispatched" any day of the year, it requires firm gas service. Because this is a cost that an actual CT would incur to provide the service presumed for the hypothetical CT, it should be included in the peaking unit equivalent cost calculation.

Finally, Variable O&M expense associated with operating the hypothetical CT should also be included in the peaking unit equivalent cost calculation because these expenses are necessary to generate electricity at a CT.

Q. PLEASE QUANTIFY THE IMPACT ON THE PEAKING UNIT EQUIVALENT COST CALCULATION FROM THESE PROPOSED CHANGES.

A. Based on the Company's experience and information available regarding costs associated with combustion turbines, the startup costs, variable O&M, and firm gas components combine to add between $38 - $39/MWh to the peaking unit equivalent cost calculation depending on the month of the year. The details behind this calculation can be found in Exhibit AEV 8.

(c) <u>Gains and Losses from Incidental Gas Sales</u>

Q. WHY IS THE COMPANY ALSO PROPOSING TO TRACK GAINS AND LOSSES FROM INCIDENTAL GAS SALES THROUGH TARIFF PPA?

A. Like PJM LSE OATT charges and credits and FAC Purchased Power Limitation expenses, gains and losses from the incidental sales of natural gas that the Company had purchased for use at Big Sandy Unit 1, but could not use or store, are highly volatile and largely outside of the Company's control. Additional information about the gains and losses from incidental gas sales is included in the testimony of Company Witness Rogness.

Q. IS THE COMPANY PROPOSING ADDITIONAL CHANGES TO TARIFF PPA IN THIS PROCEEDING?

A. Yes. In addition to tracking and recovering the difference between the costs described above, and the amount of those costs included in base rates, the Company is proposing to change the structure of the Power Purchase Adjustment itself from a monthly adjusting surcharge to an annually updated surcharge. The Company also proposes to change the rate structure from a percentage of revenue charge to a structure that includes a per-kWh

Calculation of Proposed Peaking Unit Equivalent Cost Calculation Adjustment

	Firm Gas Adjustment Calculation					
	$/MMBtu	Heat Rate	$/MWh	Startup Costs $/MWh	Variable O&M $/MWh	Total $/MWh Adjustment
January	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
February	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
March	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
April	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
May	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
June	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
July	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
August	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
September	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
October	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
November	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
December	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87

Proposed new Peaking Unit Equivalent cost calculation = (Daily Gas Price * Heat Rate/1000) + Total $/MWh Adjustment

Firm Reservation Rate, per Big Sandy Agreement ($.20/MMBtu)
Firm Surcharges, as stated in TCO tariff ($.0545/MMBtu)
Firm Transportation Commodity Rate ($0.0104/MMBtu)
Transportation Retainage, as stated in TCO tariff (1.893% or ~$0.058 on $3 gas)
Park and Lend Rate, as stated in the TCO tariff ($0.1939 winter and $0.1327 summer)
FERC Annual Charge Adjustment (ACA) ($0.0013/MMbtu)

DATA REQUEST

1_6 Refer to Kentucky Power's use of the PUE proxy methodology. Refer also to the Excel file attached to the response to Staff 1-16 named KPCO_R_KPSC_1_16_Attachment 2. Refer further to worksheet tab 06-21 Hourly Purch Alloc and the calculation of the Peaking Unit Equivalent $/MWh in column L. The calculations in column L add a cost of $33.48 per MWh to the calculated cost of gas to determine the Peaking Unit Equivalent $/MWh.

a. Please confirm that the $33.38 per MWh is added to the cost calculated for each hour in the determination of the Peaking Unit Equivalent $/MWh for each summer month during 2021. If not confirmed, please explain.

b. Please confirm that the $33.38 per MWh is added to the cost calculated for each hour in the determination of the Peaking Unit Equivalent $/MWh for each non-summer month during 2021. If not confirmed, please explain.

c. Please explain why the $33.38 per MWh cost is added in each individual hour in column L.

d. Please describe what the $33.38 per MWh addition represents and explain all reasons why it is added to the determination of the Peaking Unit Equivalent $/MWh.

e. Please describe how the $33.38 per MWh additional amount was determined. In addition, please provide copies of all source documentation and the calculations of this addition in electronic format with all formulas intact.

f. Please indicate whether the $33.38 per MWh addition remains constant in all months and in all years or whether it changes periodically. In addition, describe why it stays the same or why it changes.

RESPONSE

a. Confirmed.

b. Confirmed.

c. The $33.48 cost added to every hour in column L is comprised of a $30.00 adder for fixed start-up costs plus $3.48 adder for variable O&M pursuant to the Commission's January 18, 2018 and February 27, 2018 order in Case No. 2017-00179 approving the inclusion of variable O&M and fixed start-up costs in the PUE.

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d. Please see the Company's response to part c of this question.

e. Please see Exhibit AEV-8 filed in Case No. 2017-00179 by Company witness Vaughan for the requested information.

f. The Company has not updated this adder since it was first added to the calculation consistent with the Commission's February 27, 2018 order in Case No. 2017-00179.

Witness: Jason M. Stegall

Kentucky Power Company
KPSC Case No. 2022-00036
Commission Staff's Third Set of Data Requests
Dated June 7, 2022

DATA REQUEST

KPSC 3_2 For each month in the current six-month review period, provide the amounts of purchased power fuel during scheduled/extended outages and forced outages in both kwh and dollars and the amounts of purchased power cost recovered through the Fuel Adjustment Clause and through the Purchase Power Agreement and any amounts not recovered through either.

RESPONSE

The Company requires additional time to complete and confirm its substantive response. Kentucky Power proposes to file its supplemental response to this data request, subject to its motion for an extension filed today, on or before June 22, 2022.

June 22, 2022, Supplemental Response

Please see KPCO_R_KPSC_3_2_Attachment1 for the requested information to the extent available. Kentucky Power Company does not track purchased power data in the detail requested for scheduled or extended outages. The demand charge referenced on tab "kWh" line No. 9 is not associated with volumetric usage (i.e., kWh), therefore we cannot identify the kWh portion associated with the Purchase Power Agreement. Purchased Power is not solely determined on the basis of kWh.

Witness: Scott E. Bishop

	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021	Total
Total Purchased Power Expense	$4,993,884	$7,334,436	$6,305,000	$10,133,280	$6,332,408	$13,892,770	$48,991,778
Less: Purchased Power Recovered throug the FAC	$5,492,357	$7,079,661	$6,311,744	$8,309,733	$5,621,041	$13,581,332	$46,395,868
Less: Purchased Power Recovered through PPA Rider	$17,789	$162,620	$0	$893,124	$978,689	$346,838	$2,399,061
Net Unrecovered Purchased Power	($516,262)	$92,154	($6,744)	$930,423	($267,322)	($35,400)	$196,849

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Line No.	PPA Costs by Account per the Company's Income Statements							
1		KYP_CORP_CONSOL	May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021
2	5550001	Purch Pwr-NonTrading-Nonassoc	2,892,363.76	2,092,846.68	660,242.53	3,143,982.20	4,143,520.51	13,034,048.13
3	5550027	Purch Pwr-Non-Fuel Portion-Aff	5,520,707.92	5,877,422.14	5,812,907.60	6,547,681.05	5,644,930.43	6,441,026.38
4	5550039	PJM Inadvertent Mtr Res-OSS	(86.42)	492.10	1,215.71	1,811.92	212.47	(103.46)
5	5550040	PJM Inadvertent Mtr Res-LSE	648.59	1,018.69	4,353.78	7,908.87	1,886.87	(1,028.36)
6	5550046	Purch Power-Fuel Portion-Affil	2,240,778.00	4,224,699.00	4,452,338.00	4,163,148.00	491,687.00	(150,251.00)
7	5550074	PJM Reactive-Charge	174,322.82	185,316.62	175,404.57	176,098.29	172,744.88	175,738.19
8	5550075	PJM Reactive-Credit	(119,572.89)	(119,573.10)	(119,572.89)	(119,572.89)	(115,715.91)	(115,587.12)
9	5550076	PJM Black Start-Charge	70,955.28	70,035.23	70,815.10	69,684.28	72,112.07	72,129.57
10	5550078	PJM Regulation-Charge	5,938.07	6,406.78	9,687.41	34,353.92	40,946.69	93,291.88
11	5550079	PJM Regulation-Credit	(4,103.95)	(3,270.18)	(7,331.07)	(15,474.50)	(19,570.04)	(15,057.02)
12	5550080	PJM Hourly Net Purch.-FERC	585,863.67	1,296,530.95	1,571,096.83	2,590,338.45	2,096,559.01	1,190,623.59
13	5550083	PJM Spinning Reserve-Charge	26,758.90	29,741.08	23,341.48	44,931.96	42,303.18	70,914.22
14	5550084	PJM Spinning Reserve-Credit	(10,596.52)	(3,729.49)	(3,450.66)	(4,942.00)	(2,714.75)	(3,370.37)
15	5550090	PJM 30m Suppl Rserv Charge LSE	1,982.74	4,332.68	9,804.51	12,775.63	10,682.04	3,286.90
16	5550094	Purchased Power - Fuel	-	-	-	-	-	-
17	5550099	PJM Purchases-non-ECR-Auction	-	-	-	-	-	-
18	5550123	PJM OpRes-LSE-Charge	36,391.24	31,250.14	63,137.28	106,732.01	41,756.73	52,434.11
19	5550124	PJM Implicit Congestion-LSE	368,523.16	428,512.04	1,309,849.54	1,387,214.31	301,809.85	789,198.89
20	5550132	PJM FTR Revenue-LSE	(461,685.24)	(308,690.27)	(1,298,813.09)	(900,707.31)	(269,515.86)	(486,956.95)
21	5550137	PJM OpRes-LSE-Credit	(2,485.14)	(2,578.10)	(129.32)	(1,179.02)	(1,846.00)	(3,296.87)
22	5550153	PurchPower-Rockport Def-NonAff	(1,249,999.99)	(1,249,999.99)	(1,249,999.99)	(1,249,999.99)	(1,249,999.99)	(1,249,999.99)
23	5550326	PJM Transm Loss Charges - LSE	543,134.04	802,765.34	839,433.95	910,880.96	753,195.58	631,570.62
24	5550327	PJM Transm Loss Credits-LSE	(103,570.25)	(150,350.16)	(204,716.37)	(225,598.51)	(177,645.36)	(194,597.56)
25	5550328	PJM FC Penalty Credit	(1,675.72)	(1,320.50)	(1,707.14)	893.05	(0.86)	(217.09)
26		Total Purchased Power Cost	10,514,592.07	13,211,857.68	12,117,907.76	16,680,960.68	11,977,338.54	20,333,796.69
27								
28	Less:	Rockport UPA Demand Cost (5550027)	5,520,707.92	5,877,422.14	5,812,907.60	6,547,681.05	5,644,930.43	6,441,026.38
29								
30		Purchased Power Subject to Rider Recovery	4,993,884.15	7,334,435.54	6,305,000.16	10,133,279.63	6,332,408.11	13,892,770.31
31								
32	Costs Recovered Through the PPA							
33			May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021
34		Curent Month Retail Revenue Ratio Source: the Company's accounting files	98.70%	98.78%	98.79%	98.99%	98.91%	98.68%
35		Total FO Replacement Cost Excluded from FAC Source: The "TOTAL FO REPLACEMENT COST EXCLUDED FROM FAC" cost as calculated in the monthly Peaking Unit Equivalent ("PUE") Files	18,024.15	164,627.04	-	902,224.26	989,426.98	351,470.66
36		Cost Recovered Through the PPA (Ln 31 * Ln 32)	17,788.94	162,620.25	-	893,123.93	978,689.38	346,838.00
37								
38	FAC Data - Monthly Final Fuel Cost Schedule As Filed							
39			May 2021	Jun 2021	Jul 2021	Aug 2021	Sep 2021	Oct 2021
40		Net Energy Cost Economy Purchases	-	-	-	-	-	-
41		Identifiable Fuel Cost - Other Purchases	5,537,921.00	7,214,132.00	6,313,099.00	9,534,544.00	6,643,250.00	13,962,570.00
42		Identifiable Fuel Cost Substitute	198,905.00	299,096.00	-	1,579,375.00	1,664,340.00	717,836.00
43		Purchase Adjustment for PUE	27,541.00	-	1,355.00	322,570.00	32,806.00	29,766.00
44		Fuel Cost Assinged During Forced Outages	180,882.00	164,625.00	-	677,134.00	674,937.00	366,364.00
45		Subtotal	5,492,357.00	7,079,661.00	6,311,744.00	8,309,733.00	5,621,041.00	13,581,332.00

TARIFF P.P.A.
(Purchase Power Adjustment)

APPLICABLE.

To Tariffs R.S., R.S.D., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, G.S., S.G.S.-T.O.D., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S. – I.R.P., C.S. Coal, M.W., O.L. and S.L.

RATE.

The annual purchase power adjustment factor will be computed using the following formula:

1. Annual Purchase Power Net Costs (PPANC)

   PPANC = N+CSIRP+OATT+RKP+RP-BPP

   Where:
   BPP = The annual amount of purchase power costs included in base rates, $98,165,699.

   a. N = The annual cost of power purchased by the Company through new Purchase Power Agreements and purchased power expense from avoided cost payments to net metering customers under tariff N.M.S.II. All new purchase power agreements shall be approved by the Commission to the extent required by KRS 278.300.
   b. CSIRP = The net annual cost of any credits provided to customers under Tariff C.S.-I.R.P., Tariff D.R.S., Tariff V.C.S. and special contracts for interruptible service above or below the $454,997 included in BPP. T
   c. OATT = 100% The net annual PJM load-serving entity Open Access Transmission Tariff Charges above or below the $96,896,495 included in BPP, less the transmission return difference pursuant to the Commission approved Settlement agreement in Case No. 2017-00179.
   d. RKP = Rockport related items includable in Tariff PPA pursuant to the Commission approved Settlement agreement in Case No. 2017-00179:
      1. Increase in Rockport collection resulting from reduction in base rate deferral;
      2. Rockport deferral amount to be recovered;
      3. Rockport fixed cost savings; and
      4. Rockport offset estimate and true-up.
      5. Final (over)/under recovery associated with tariff CC following its expiration
   e. RP = The cost of fuel related to substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages above or below the $814,208 included in BPP.

(Cont'd on Sheet No. 35-2)

DATE OF ISSUE: December 28, 2021
DATE EFFECTIVE: Service Rendered On And After January 28, 2022
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority Of an Order of the Public Service Commission
In Case No. XXXX-XXXXX Dated XXXX XX, XXXX

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
1/28/2022
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES.

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.	$0.00594	--
S.G.S.-T.O.D.	$0.00483	--
M.G.S.-T.O.D.	$0.00483	--
G.S.	$0.00483	--
L.G.S., L.G.S.-T.O.D.	$0.00012	$1.40
L.G.S.-L.M.-T.O.D.	$0.00443	--
I.G.S. and C.S.-I.R.P.	$0.00012	$1.66
M.W.	$0.00330	--
O.L.	$0.00075	--
S.L.	$0.00075	--

I

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the LGS, LGS-T.O.D, IGS, and CS-I.R.P. tariff classes.

The Purchase Power Adjustment factors shall be modified annually using the following formula:

The Purchase Power Adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total}) + PPA(D) \times (CP_{Class} / CP_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demand billing:

$$\text{kWh Factor} = \frac{PPA(E) \times (BE_{Class} / BE_{Total})}{BE_{Class}}$$

$$\text{kW Factor} = \frac{PPA(D) \times (CP_{Class/} / CP_{Total})}{BD_{Class}}$$

(Cont'd on Sheet No. 35-3)

DATE OF ISSUE: August 19, 2021
DATE EFFECTIVE: Service Rendered On And After September 28, 2021
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority Of an Order of the Public Service Commission
In Case No. XXXX-XXXXX Dated XXXX XX, XXXX

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
9/28/2021
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

TARIFF P.P.A. (Cont'd)
(Purchase Power Adjustment)

RATES. (Cont'd)

Where:

1. "PPA(D)" is the actual annual retail PPA demand-related costs, plus any prior review period (over)/under recovery.
2. "PPA(E) is the actual annual retail PPA energy-related costs, plus any prior review period (over)/under recovery.
3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CP_{Class}" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class	BE_{Class}	CP/kWh Ratio	CP_{Class}	
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and R.S.-T.O.D. 2, R.S.D.		0.02428%		I
S.G.S.-T.O.D.		0.01962%		R
M.G.S.-T.O.D.		0.01962%		
G.S.		0.01962%		
L.G.S., L.G.S.-T.O.D		0.01798%		I
L.G.S.-L.M.-T.O.D.		0.01798%		
I.G.S. and C.S.-I.R.P.		0.01232%		
M.W.		0.01326%		R
O.L.		0.00263%		I
S.L.		0.00262%		I

6. "BE_{Total}" is the sum of the BE_{Class} for all tariff classes.
7. "CP_{Total}" is the sum of the CP_{Class} for all tariff classes.
8. The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.41% and the KPSC Maintenance Fee of 0.1956% and other similar revenue based taxes or assessments occasioned by the Purchase Power Adjustment Rider revenues. I R
9. The annual PPA factors shall be filed with the Commission by August 15 of each year, with rates to begin with the October billing period, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

DATE OF ISSUE: April 9, 2021
DATE EFFECTIVE: Service Rendered On And After January 14, 2021
ISSUED BY: /s/ Brian K. West
TITLE: Vice President, Regulatory & Finance
By Authority of Orders of the Public Service Commission
In Case No. 2020-00174 dated January 13, 2021; January 15, 2021; February 22, 2021, and March 17, 2021

KENTUCKY
PUBLIC SERVICE COMMISSION
Linda C. Bridwell
Executive Director
Linda C. Bridwell
EFFECTIVE
1/14/2021
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Kentucky Power Company
KPSC Case No. 2022-00036
KIUC First Set of Data Requests
Dated May 9, 2022

DATA REQUEST

1_3 With respect to the FAC limitation on the recovery of purchase power costs due to forced outages:

a. Please confirm that the limitation on the recovery of purchase power costs due to forced outages has not been applied by Kentucky Power with respect to Rockport.

b. Please explain why the forced outage limitation does not apply to Rockport.

c. If there is a Commission decision addressing the recovery of purchase power costs due to forced outages at Rockport please provide a citation.

RESPONSE

a. Not applicable. The limitation is not applicable because Kentucky Power receives its share of Rockport generation through a Unit Power Agreement.

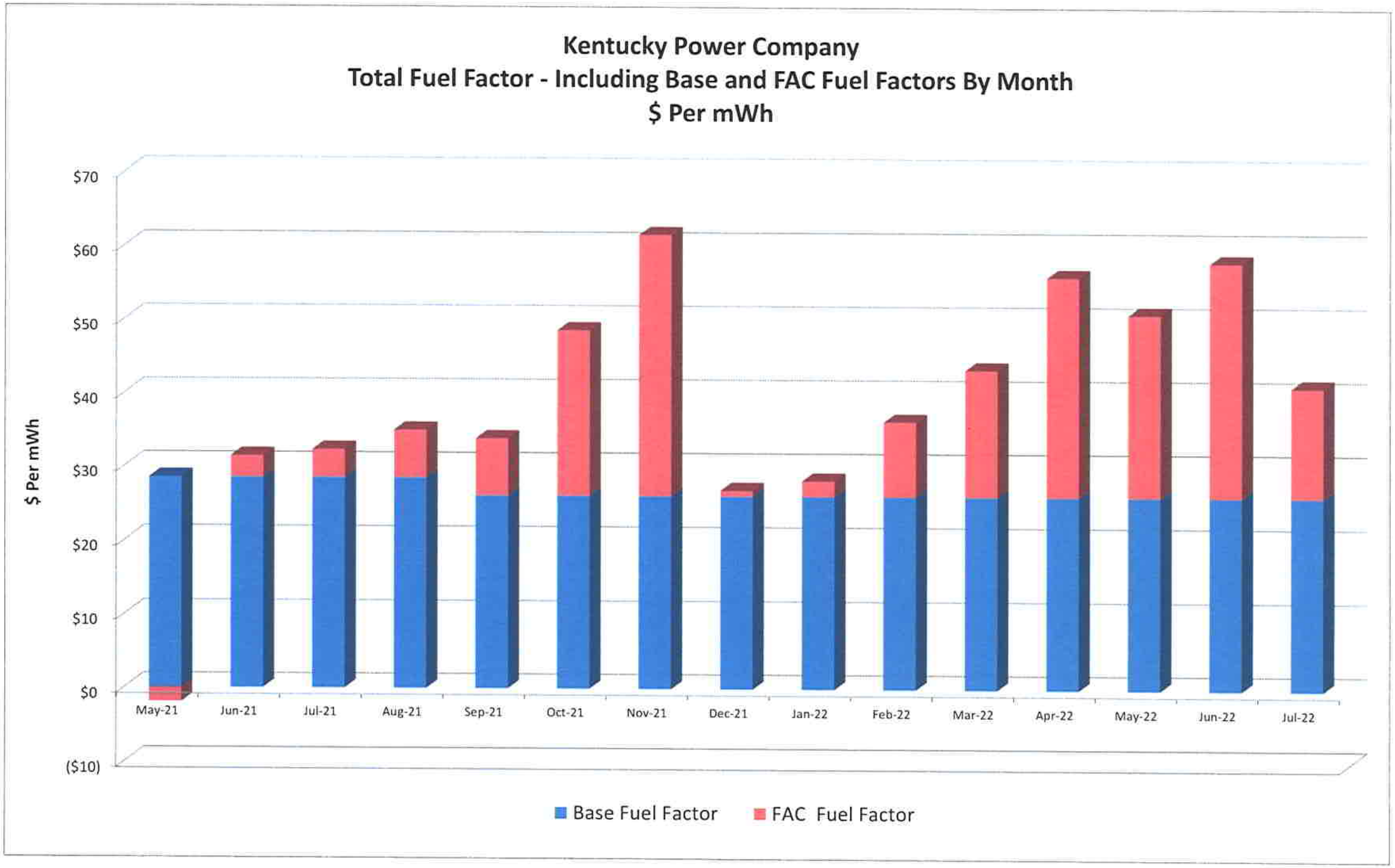
b. The Company does not have an ownership or leased interest in the Rockport Plant. Kentucky Power receives its share of Rockport generation through a Unit Power Agreement.

c. The Company is not aware of a Commission order addressing recovery of purchase power costs due to forced outages *specifically* at Rockport.

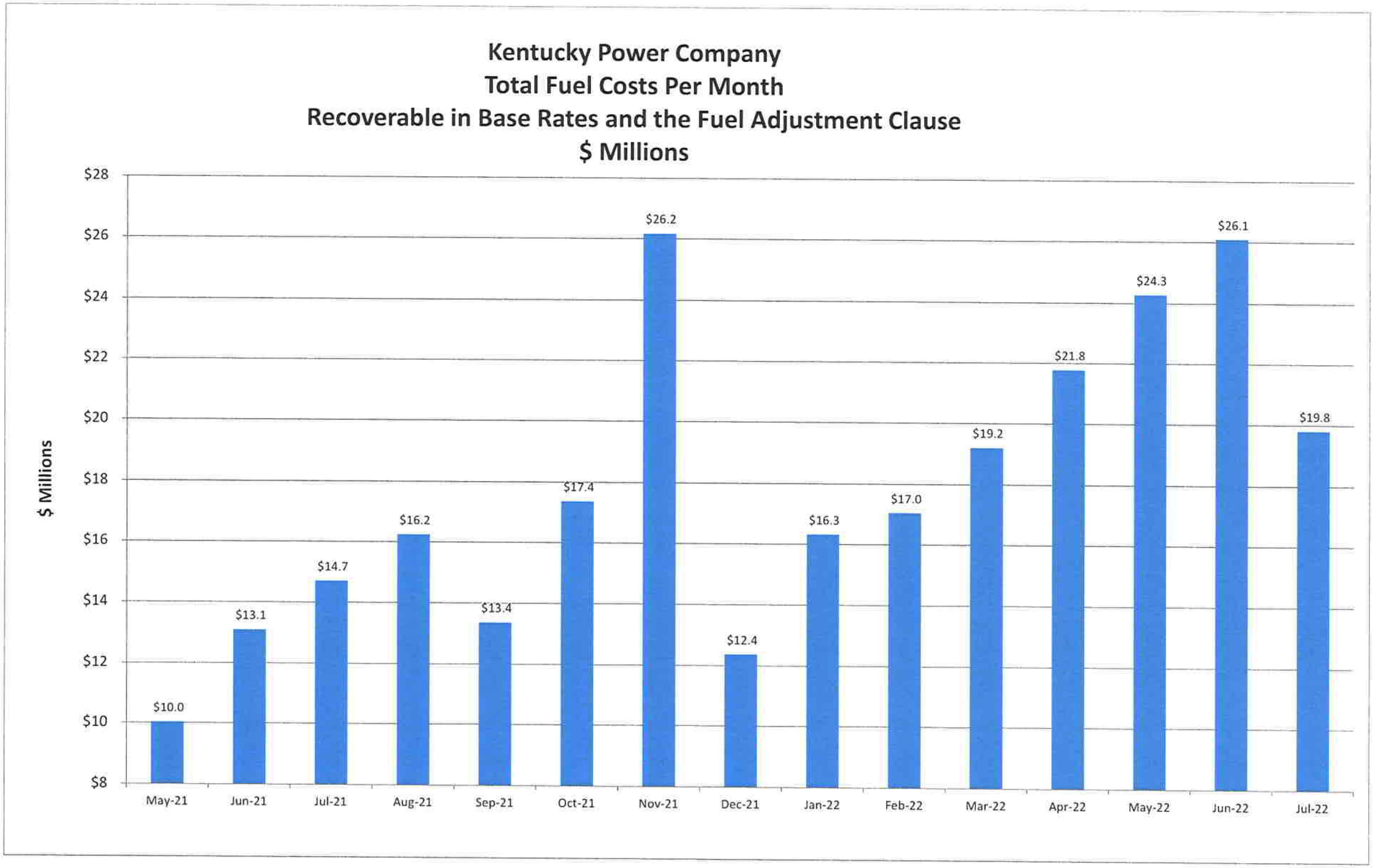
Witness: Scott E. Bishop

#4

Fuel Cost Charts & Data



Kentucky Power Company
Total Fuel Factor - Including Base and FAC Fuel Factors By Month
$ Per mWh
$ Per mWh
$70
$60
$50
$40
$30
$20
$10
$0
($10)
May-21
Jun-21
Jul-21
Aug-21
Sep-21
Oct-21
Nov-21
Dec-21
Jan-22
Feb-22
Mar-22
Apr-22
May-22
Jun-22
Jul-22
Base Fuel Factor
FAC Fuel Factor


Kentucky Power Company
Total Fuel Costs Per Month
Recoverable in Base Rates and the Fuel Adjustment Clause
$ Millions
$ Millions
$28
$26
$24
$22
$20
$18
$16
$14
$12
$10
$8
$10.0
$13.1
$14.7
$16.2
$13.4
$17.4
$26.2
$12.4
$16.3
$17.0
$19.2
$21.8
$24.3
$26.1
$19.8
May-21
Jun-21
Jul-21
Aug-21
Sep-21
Oct-21
Nov-21
Dec-21
Jan-22
Feb-22
Mar-22
Apr-22
May-22
Jun-22
Jul-22

Page 5 of 5 in FAC Filings

Estimated Fuel Cost Month	Per kWh Base Fuel Factor	FAC Fuel Factor	Total Fuel Factor	Actual Costs Recovered Through FAC	PJM Related Costs	Actual Costs Recovered Through FAC W/O PJM	Forced Outage Purchases Assigned	Less: Forced Outage Fuel Assigned	Forced Outage Removed From FAC Total	Retail Allocation	Forced Outage Removed From FAC Jurisdictional
Jan-21	0.02851	0.00057	0.02908	15,124,428	474,071	14,650,357	-	-	-	98.81%	-
Feb-21	0.02851	0.00598	0.03449	16,531,741	884,355	15,647,386	1,990,955	1,525,716	465,239	98.81%	459,695
Mar-21	0.02851	0.00147	0.02998	12,875,086	(160,938)	13,036,024	3,232,948	3,043,570	189,378	98.81%	187,121
Apr-21	0.02851	0.00222	0.03073	11,062,619	339,639	10,722,980	4,175,182	3,745,546	429,636	98.81%	424,516
May-21	0.02851	-0.00194	0.02657	10,323,161	393,967	9,929,194	198,905	180,882	18,023	98.70% x	17,789
Jun-21	0.02851	0.00296	0.03147	12,922,780	821,224	12,101,556	299,096	164,625	134,471	98.78% x	132,830
Jul-21	0.02851	0.00385	0.03236	14,690,458	787,199	13,903,259	-	-	-	98.79% x	-
Aug-21	0.02851	0.00654	0.03505	15,152,462	1,327,927	13,824,535	1,579,375	677,134	902,241	98.99% x	893,128
Sep-21	0.02612	0.00780	0.03392	13,582,685	584,818	12,997,867	1,664,340	674,937	989,403	98.91% x	978,619
Oct-21	0.02612	0.02252	0.04864	17,191,990	980,446	16,211,544	717,836	366,364	351,472	98.68% x	346,833
Nov-21	0.02612	0.03556	0.06168	25,159,458	1,054,057	24,105,401	1,264,345	528,027	736,318	98.81%	727,544
Dec-21	0.02612	0.00080	0.02692	15,760,531	464,595	15,295,936	1,230,412	625,037	605,375	98.81%	598,161
Jan-22	0.02612	0.00213	0.02825	19,529,185	(525,969)	20,055,154	-	-	-	98.81%	-
Feb-22	0.02612	0.01024	0.03636	19,267,537	(116,223)	19,383,760	1,694,183	266,131	1,428,052	98.81%	1,411,034
Mar-22	0.02612	0.01729	0.04341	22,440,362	622,595	21,817,767	2,326,305	2,326,305	-	98.81%	-
Apr-22	0.02612	0.02990	0.05602	19,061,024	1,178,458	17,882,566	718,115	357,019	361,096	98.81%	356,793
May-22	0.02612	0.02485	0.05097	22,099,904	219,971	21,879,933	-	-	-	98.81%	-
Jun-22	0.02612	0.03193	0.05805			-			-	98.81%	-
Jul-22	0.02612	0.01502	0.04114								

Billing Months Are Two Months Later

X - Includes PJM Fuel Related Costs

Avg of Available Data
98.81% x

Estimated Cost Month	Per mWh Base Fuel Factor	FAC Fuel Factor	Total Fuel Factor
May-21	28.51	-1.94	26.57
Jun-21	28.51	2.96	31.47
Jul-21	28.51	3.85	32.36
Aug-21	28.51	6.54	35.05
Sep-21	26.12	7.80	33.92
Oct-21	26.12	22.52	48.64
Nov-21	26.12	35.56	61.68
Dec-21	26.12	0.80	26.92
Jan-22	26.12	2.13	28.25
Feb-22	26.12	10.24	36.36
Mar-22	26.12	17.29	43.41
Apr-22	26.12	29.90	56.02
May-22	26.12	24.85	50.97
Jun-22	26.12	31.93	58.05
Jul-22	26.12	15.02	41.14

Cost Month	Estimated Total Fuel	
May-21	$	10.0
Jun-21	$	13.1
Jul-21	$	14.7
Aug-21	$	16.2
Sep-21	$	13.4
Oct-21	$	17.4
Nov-21	$	26.2
Dec-21	$	12.4
Jan-22	$	16.3
Feb-22	$	17.0
Mar-22	$	19.2
Apr-22	$	21.8
May-22	$	24.3
Jun-22	$	26.1
Jul-22	$	19.8

Kentucky Power Company
Actual Forced Outage Amounts Removed from FAC
And Totally Recovered through PPA
$

Cost Month	Forced Outage Purchases Assigned In FAC	Less: Forced Outage Fuel Assigned In FAC	Forced Outage Removed From FAC Total	Forced Outage Removed From FAC Jurisdictional
Jan-21	-	-	-	-
Feb-21	1,990,955	1,525,716	465,239	459,695
Mar-21	3,232,948	3,043,570	189,378	187,121
Apr-21	4,175,182	3,745,546	429,636	424,516
May-21	198,905	180,882	18,023	17,789
Jun-21	299,096	164,625	134,471	132,830
Jul-21	-	-	-	-
Aug-21	1,579,375	677,134	902,241	893,128
Sep-21	1,664,340	674,937	989,403	978,619
Oct-21	717,836	366,364	351,472	346,833
Nov-21	1,264,345	528,027	736,318	727,544
Dec-21	1,230,412	625,037	605,375	598,161
Jan-22	-	-	-	-
Feb-22	1,694,183	266,131	1,428,052	1,411,034
Mar-22	2,326,305	2,326,305	-	-
Apr-22	718,115	357,019	361,096	356,793
May-22	-	-	-	-
Totals	21,091,997	14,481,293	6,610,704	6,534,063

Average Jurisdictional Factor 98.8%

#5

KIUC Ex. 2

STEP 1 & 3 | STEP 2

DAY AND HOUR ENDING	(1) FORCED OUTAGE (FO) VOLUME FROM LASOR			(2) TOTAL FO			(3) PURCHASES ASSIGNED TO INTERNAL LOAD (MWh)	(3a) MARGINAL LOSSES	(4) MINIMUM OF (2) OR (3)	(5) INCLUDE ONLY IF FO > 6 HOURS REQUIRES PURCHASES (Step 1)	(5a) DISPATCHED GENERATION	(6) NET AVAILABLE GENERATION RESOURCES	(7) INTERNAL LOAD
	Mitchell 1 KP (385)	Mitchell 2 KP (395)	Big Sandy 1 (295)	Total	Counter	Include	INPUT FROM KP Hourly Purch Alloc Tab	INPUT FROM PT	MIN (2), (3)	(4) >0 for > 6 hours	INPUT FROM POWER TRACKER	INPUT FROM POWER TRACKER	INPUT FROM POWER TRACKER
BIG SANDY U1 HAD NO FORCED OUTAGES THIS MONTH													
MITCHELL UNIT 2 HAD TWO FORCED OUTAGES THIS MONTH													
MITCHELL UNIT NO THREE FORCED OUTAGES THIS MONTH													
08/02/2021 00				-	-	-	36	8	-	-	682	920	560
08/02/2021 01				-	-	-	44	7	-	-	582	920	532
08/02/2021 02				-	-	-	6	6	-	-	519	920	514
08/02/2021 03				-	-	-	34	6	-	-	467	917	494
08/02/2021 04				-	-	-	16	6	-	-	472	920	488
08/02/2021 05				-	-	-	13	6	-	-	467	918	482
08/02/2021 06				-	-	-	33	6	-	-	472	920	494
08/02/2021 07				-	-	-	142	7	-	-	467	910	509
08/02/2021 08				-	-	-	77	7	-	-	473	920	533
08/02/2021 09				-	-	-	197	7	-	-	469	749	554
08/02/2021 10				-	-	-	115	8	-	-	493	920	587
08/02/2021 11				-	-	-	6	9	-	-	583	920	631
08/02/2021 12				-	-	-	(43)	10	(43)	-	695	920	666
08/02/2021 13				-	-	-	(66)	11	(66)	-	736	921	702
08/02/2021 14				-	-	-	(44)	12	(44)	-	781	922	731
08/02/2021 15				-	-	-	(2)	12	(2)	-	799	922	750
08/02/2021 16				-	-	-	3	12	-	-	800	923	767
08/02/2021 17				-	-	-	(18)	12	(18)	-	805	925	764
08/02/2021 18				-	-	-	81	12	-	-	816	925	764
08/02/2021 19				-	-	-	(60)	12	(60)	-	808	925	744
08/02/2021 20				-	-	-	(4)	11	(4)	-	808	924	713
08/02/2021 21				-	-	-	(24)	11	(24)	-	795	922	683
08/02/2021 22				-	-	-	28	10	-	-	787	922	667
08/02/2021 23				-	-	-	35	9	-	-	748	920	617
		Total		122,237.50			60,527.49	8,259.66			512,306.31	671,825.70	501,746.94

DAY AND HOUR ENDING	(8) PURCHASES DUE TO DEFICIENCY (Step 2)	(9) PURCHASES DUE TO F.O. DEFICIENCY (MIN STEP 1 OR 2)	(10) Net Position = Gen + losses + purchases - Load	(11) MAX FO VOLUME REQUIRING REPLACEMENT POWER			(12) AVERAGE PRICE OF PURCHASED POWER	(13) TOTAL COST OF REPLACEMENT POWER DUE TO FO	(14) FO UNIT FUEL COST FROM MONTHLY NET ENERGY REQUIREMENT REPORT			(14a) Highest of PUE or Generation Cost $/MWh	(15) TOTAL ALLOWABLE FO REPLACEMENT COST	(16) TOTAL FO REPLACEMENT COST EXCLUDED FROM FAC
	MAX [(7)-(6),0]	MIN (5),(8)	(3) + (3a) + (5a) - (7)	Mitchell 1	Mitchell 2	BS 1	INPUT FROM PowerTracker	Σ(11,) x (12)	Mitchell 1	Mitchell 2	BS1	Input from PUE Analysis	Σ ((11,) X (14,))	(13) - (15)
				129,478	226,638	37,857			$ 24.780	$ 20.838	$ 54.892			
08/02/2021 00	-	-	-	-	-	-	$ 24.233	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 01	-	-	-	-	-	-	$ 22.073	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 02	-	-	-	-	-	-	$ 20.669	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 03	-	-	-	-	-	-	$ 21.661	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 04	-	-	-	-	-	-	$ 20.838	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 05	-	-	-	-	-	-	$ 21.777	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 06	-	-	-	-	-	-	$ 22.175	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 07	-	-	-	-	-	-	$ 20.534	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 08	-	-	-	-	-	-	$ 25.663	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 09	-	-	-	-	-	-	$ 23.585	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 10	-	-	-	-	-	-	$ 30.514	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 11	-	-	-	-	-	-	$ 177.896	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 12	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 13	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 14	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 15	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 16	-	-	-	-	-	-	$ 237.363	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 17	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 18	-	-	-	-	-	-	$ 66.500	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 19	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 20	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 21	-	-	-	-	-	-	$ -	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 22	-	-	-	-	-	-	$ 53.680	$ -	$ -	$ -	$ -		$ -	$ -
08/02/2021 23	-	-	-	-	-	-	$ (16.198)	$ -	$ -	$ -	$ -		$ -	$ -
				27,425.416	-	-	$ 57.588	$ 1,579,369.68				$ 24.690	$ 677,145.42	902,224.26
														32.90
				27,425,416 kWh										

KUC - 2

Kentucky Power Purchase Allocation

August-21

Based on a 24-hour day, you will have to add an hour/subtract an hour for Daylight savings changes

Hours in Month 744

Total Rows 749

Generation and Fuel Cost data from NER

Day/Hour Ending	Total KP Purchases		KP Purchases allocated to OSS		KP Purchases allocated to Internal Load		Purchases Assigned to Internal Load Due to Forced Outage MW	Purchases Assigned to Internal Load Not Due to Forced Outage MW	$/ MWh of Purchases allocated to Internal Load	Daily Gas Price	Peaking Unit Equivalent $/MWh	Big Sandy 1 Generation Cost $/MWh	Mitchell Unit 1 KP Generation Cost $/MWh	Mitchell Unit 2 KP Generation Cost $/MWh	Rockport 1 KP Generation Cost $/MWh	Rockport 2 KP Generation Cost $/MWh	Highest of PUE or Generation Cost $/MWh	Difference in $/MWh	Total Difference in PUE & Purchase Price $
												MW Generated	MW Generated	MW Generated	MW Generated	MW Generated			
												37,857	129,478	226,638	39,365	78,968			
	KP Mwh	KP Dollars	KP Mwh	KP Dollars	KP Mwh	KP Dollars					Update for Jun-Aug	$2,078,026.61	$3,208,406.27	$4,722,780.58	$1,299,384.57	$2,500,838.48			
08/02/2021 00	43.03	1,051.90	6.78	173.42	36.25	878.48	-	36.25	24.233	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 01	43.57	961.63	-	-	43.57	961.63	-	43.57	22.073	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 02	6.41	132.51	-	-	6.41	132.51	-	6.41	20.669	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 03	34.40	745.10	-	-	34.40	745.10	-	34.40	21.661	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 04	26.55	561.91	10.54	228.29	16.01	333.62	-	16.01	20.838	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 05	21.93	472.15	8.77	185.53	13.16	286.62	-	13.16	21.777	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 06	43.58	959.52	10.51	226.35	33.06	733.18	-	33.06	22.175	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 07	162.38	3,364.57	20.43	449.94	141.94	2,914.64	-	141.94	20.534	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 08	200.64	4,538.43	123.55	2,560.01	77.09	1,978.42	-	77.09	25.663	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 09	336.34	7,798.40	139.13	3,147.16	197.21	4,651.24	-	197.21	23.585	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 10	367.96	9,372.23	253.22	5,871.15	114.74	3,501.09	-	114.74	30.514	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 11	286.95	8,183.90	281.21	7,162.78	5.74	1,021.12	-	5.74	177.896	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	106.7239164	612.60
08/02/2021 12	205.06	8,124.89	247.80	7,067.19	(42.74)	1,057.70	-	(42.74)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 13	139.00	5,868.01	205.06	8,124.89	(66.05)	(2,256.88)	-	(66.05)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 14	94.98	3,520.23	139.00	5,868.01	(44.03)	(2,347.78)	-	(44.03)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 15	93.38	3,073.83	94.98	3,520.23	(1.59)	(446.40)	-	(1.59)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 16	96.41	3,792.33	93.38	3,073.83	3.03	718.50	-	3.03	237.363	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	166.191292	503.06
08/02/2021 17	78.76	3,821.19	96.41	3,792.33	(17.65)	28.86	-	(17.65)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 18	160.16	9,233.85	78.76	3,821.19	81.39	5,412.66	-	81.39	66.500	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 19	100.27	4,132.45	160.16	9,233.85	(59.89)	(5,101.41)	-	(59.89)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 20	96.20	4,824.28	100.27	4,132.45	(4.07)	691.84	-	(4.07)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 21	72.64	2,432.09	96.20	4,824.28	(23.56)	(2,392.20)	-	(23.56)	0.000	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 22	100.78	3,942.59	72.64	2,432.09	28.14	1,510.50	-	28.14	53.680	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
08/02/2021 23	135.69	3,377.16	100.78	3,942.59	34.91	(565.43)	-	34.91	-16.198	$3.49	71.172	54.892	24.780	20.838	33.008	31.669	71.172	0	0.00
	113,923.04	**5,734,320.52**	-	-	**60,527.49**	**3,145,704.04**	**27,135.61**	**33,391.88**	**37,716.30**		**57,609.79**	**40,839.33**	**18,436.01**	**15,503.78**	**24,558.14**	**23,561.77**	**57609.792**	**24,113.15**	**322,569.63**

Purchase Cost comparison to PUE

Avg Purch Cost - Internal	Min Daily Gas Price	75% of Min	
$51.97	3.490	$28.27	Update for Jun-Aug
		Difference	
		$23.70	PUE calc is applicable

#6

CT Operations Data from KU/LG&E and EKPC

Including Sharefile Link To Underlying Data

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 JOINT INTEGRATED RESOURCE PLAN OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY	))))	CASE NO. 2021-00393

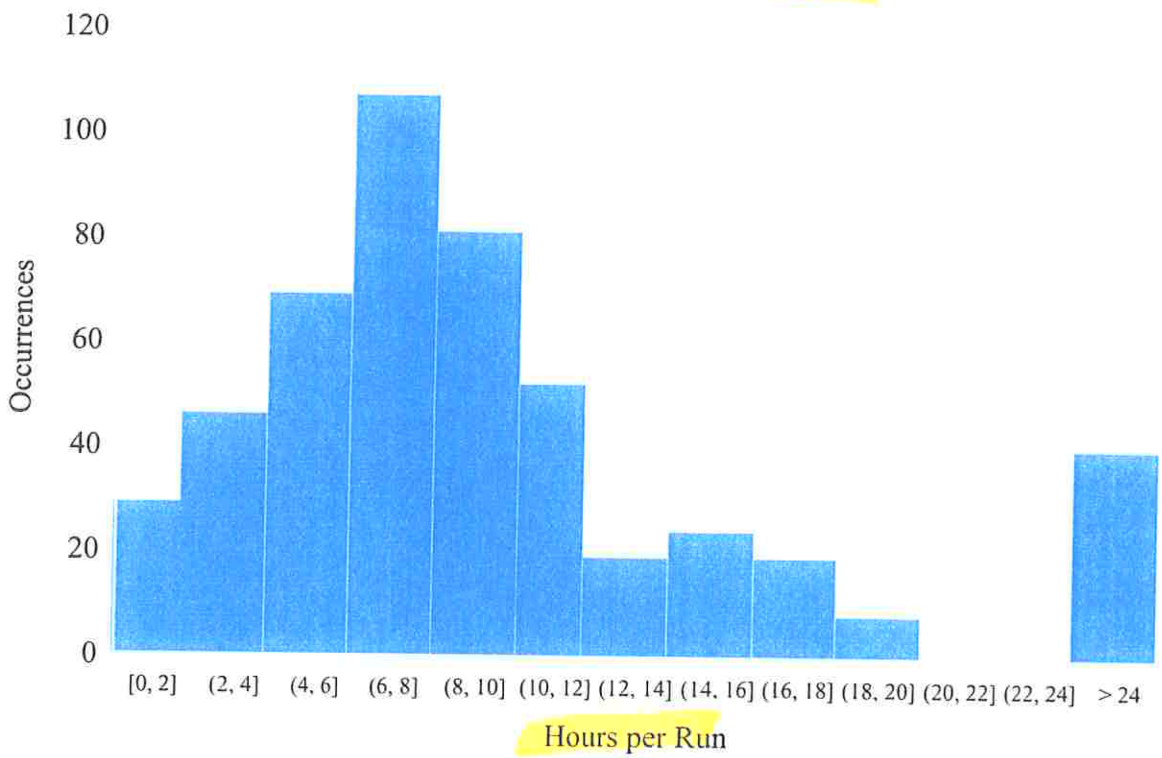
RESPONSIVE COMMENTS OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY

Filed: May 20, 2022

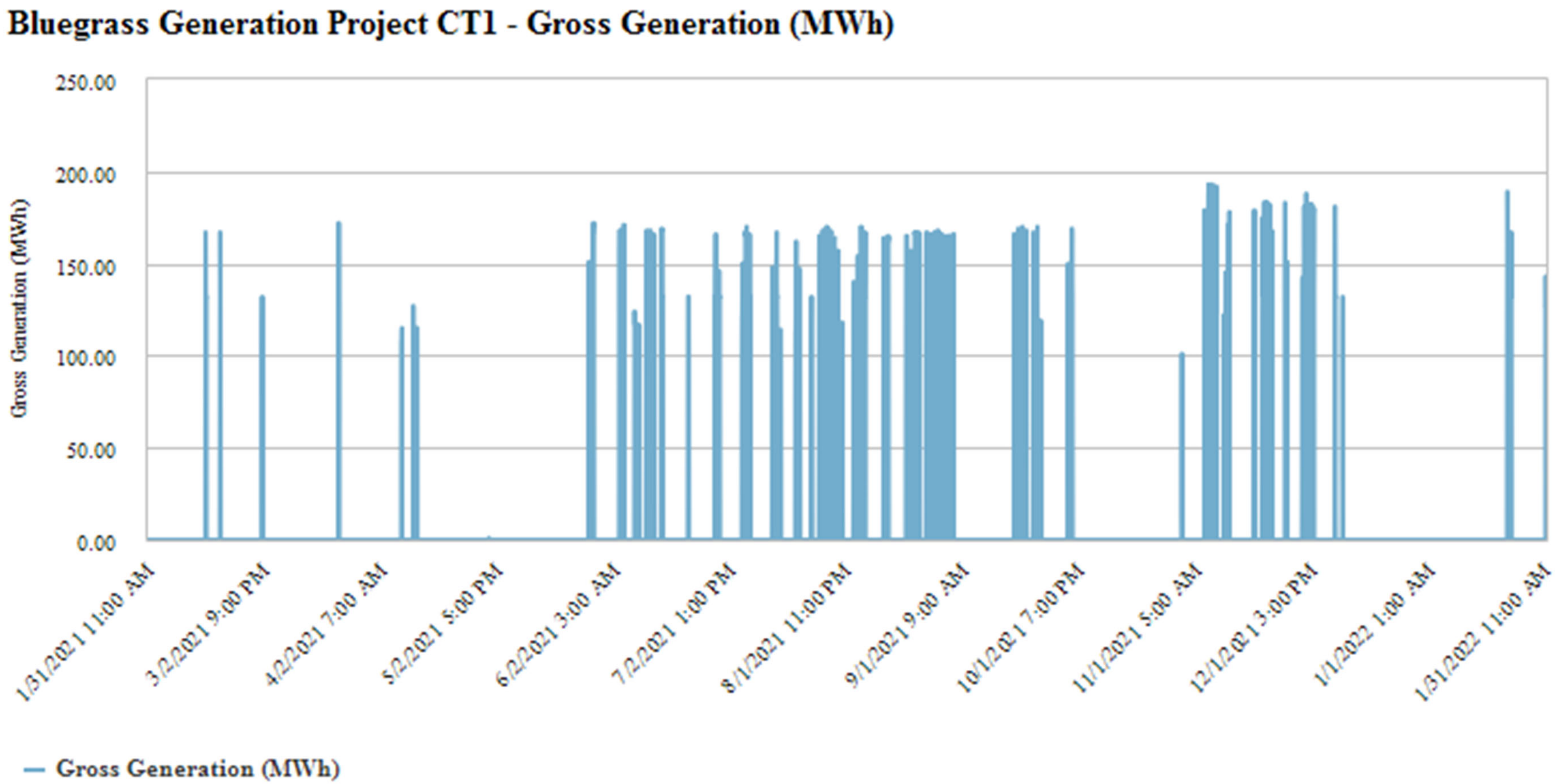
2

Understanding these constraints on battery performance helps explain why simply pairing solar with relatively small amounts of battery storage cannot produce the same production profile as conventional, fossil-fueled resources. To illustrate further, Figure 1 below shows the distribution of run times for the Trimble County SCCTs in 2019 (excluding test runs). When the Companies dispatched the Trimble County SCCTs economically to serve load in 2019, 85% of runs were greater than four hours and 71% of the runs were greater than eight hours. To achieve that kind of performance and operational flexibility with battery storage would require significant amounts batteries, as well as the resources to charge them so they could be available when needed. Obviously, pairing a battery only with intermittent resources such as solar would reduce charging flexibility and capability, meaning that a greater quantity of batteries or intermittent resources (or both) would be required to be as dispatchable as SCCTs.

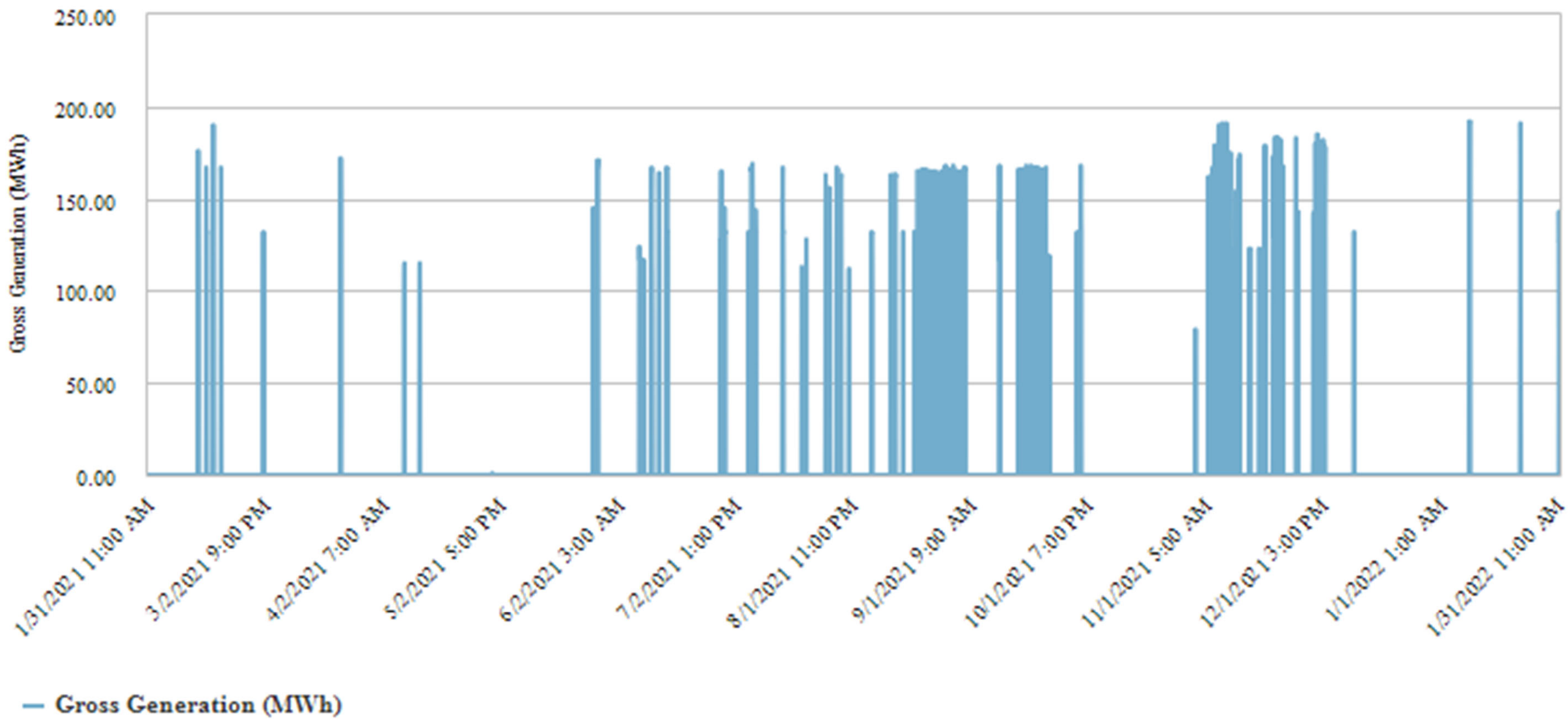
Figure 1: Distribution of Run Times for Trimble County SCCTs in 2019



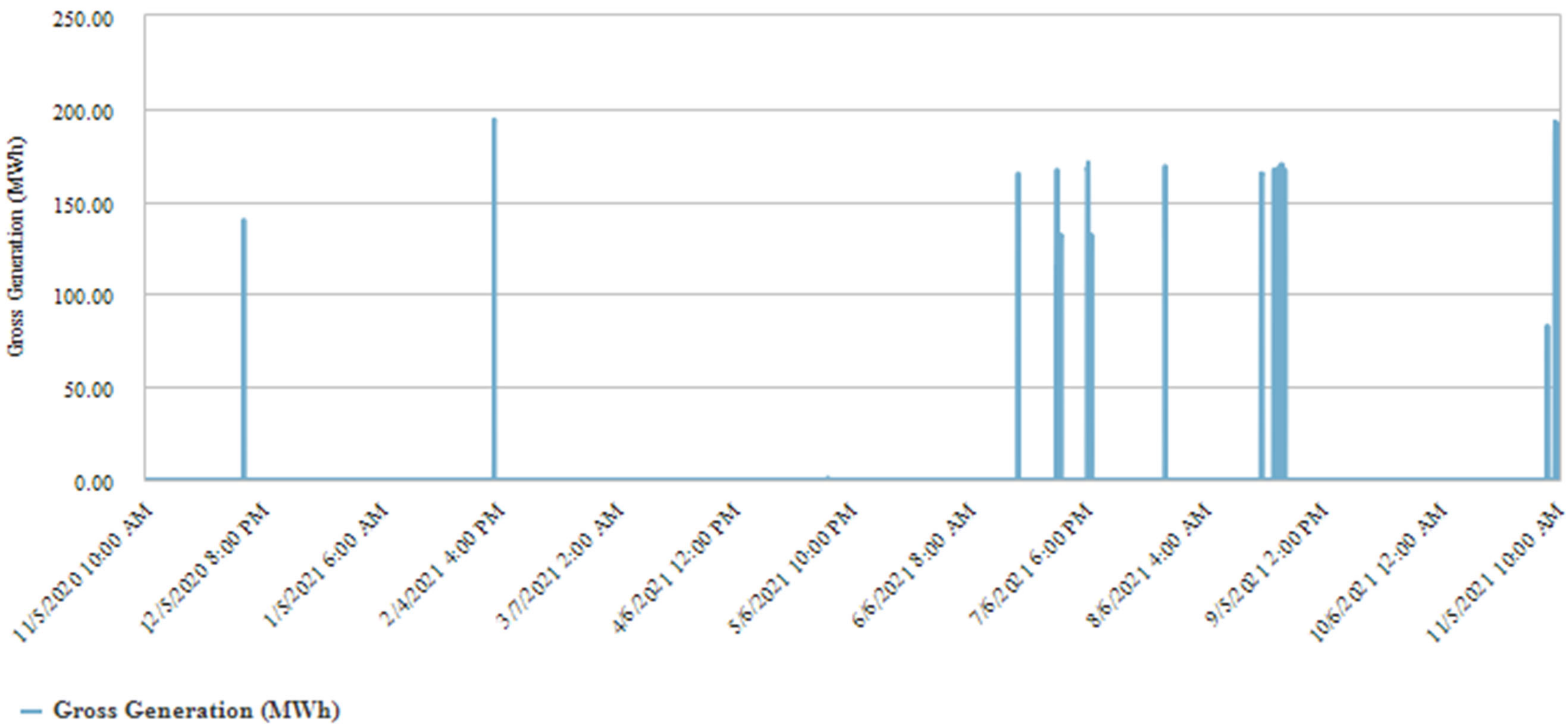
3


Bluegrass Generation Project CT1 - Gross Generation (MWh)
Gross Generation (MWh)
250.00
200.00
150.00
100.00
50.00
0.00
1/31/2021 11:00 AM
3/2/2021 9:00 PM
4/2/2021 7:00 AM
5/2/2021 5:00 PM
6/2/2021 3:00 AM
7/2/2021 1:00 PM
8/1/2021 11:00 PM
9/1/2021 9:00 AM
10/1/2021 7:00 PM
11/1/2021 5:00 AM
12/1/2021 3:00 PM
1/1/2022 1:00 AM
1/31/2022 11:00 AM
Gross Generation (MWh)

Bluegrass Generation Project CT2 - Gross Generation (MWh)



Bluegrass Generation Project CT3 - Gross Generation (MWh)



East Kentucky Power Cooperative
Annual Number of Times When Generation Occurred
And Weighted Average Duration in Hours
Bluegrass CTs Units 1, 2, and 3
Calendar Year 2021

	Number of Times Generation Occurred	Weighted Average Duration of Generation in Number Of Hours
Bluegrass CT 1	90	7.46
Bluegrass CT 2	92	6.95
Bluegrass CT 3	17	6.76
Total	199	7.16

#6 Sharefile Link
To Underlying Data

https://bkllawfirm.sharefile.com/d-s7a3ad77445c644e491aaf5b89b0f4aea

#7

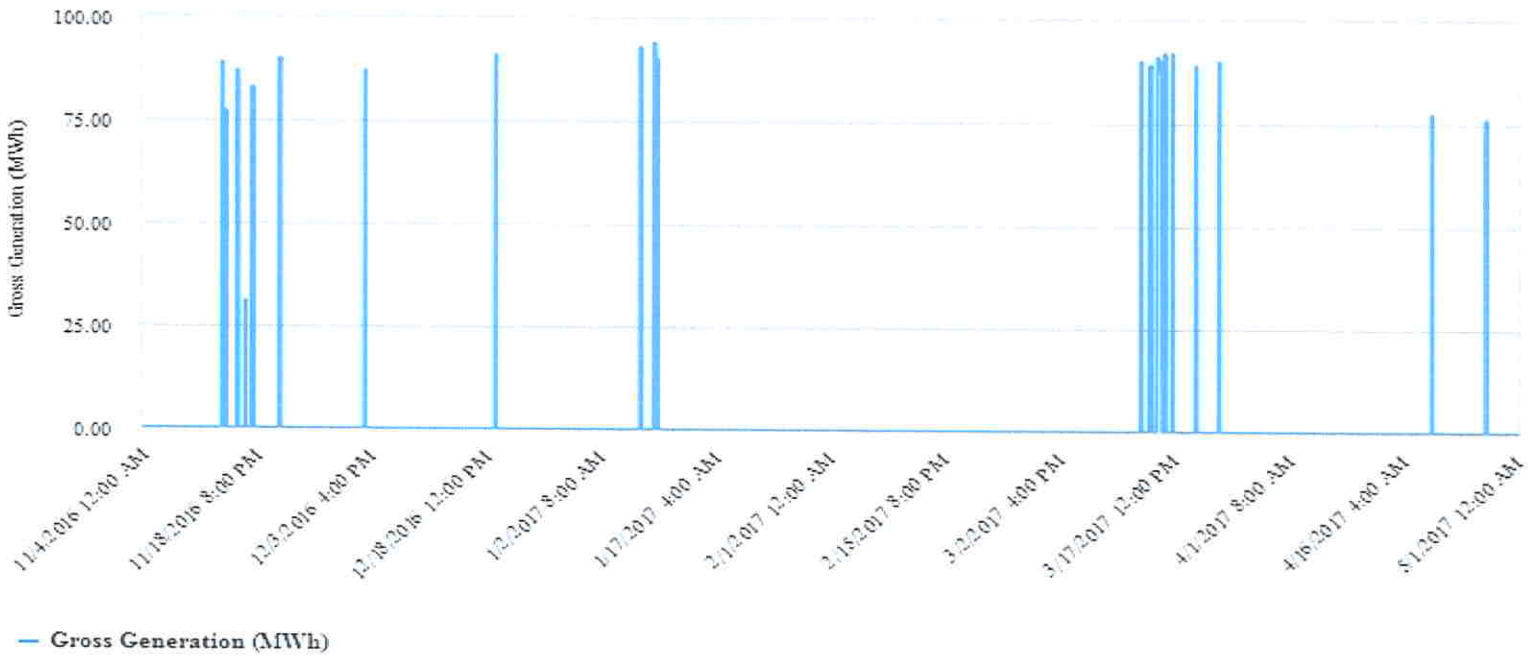
Ceredo Unit 1 2016/2017 Operations Chart Including Sharefile Link To Underlying Data

S&P Capital IQ PRO

Ceredo | Unit Hourly Operations (Chart)

Periods From: 11/04/2016 To: 05/01/2017

Ceredo CT 01 - Gross Generation (MWh)



This data is from EPA's Continuous Emissions Monitoring System (CEMS).
Hourly data is reported as hour beginning.

#7 Sharefile Link
To Underlying Data

https://bkllawfirm.sharefile.com/d-s647b5d22286f4108a96f4eb867e7306d

#8

KIUC Ex. 3

Kentucky Power Company
Average and Maximum Market Purchases (Non-Rockport) Assigned to Native Load Not Due to Forced Outages
MW

Month	Market Purchases (Non-Rockport) Assigned to Native Load Not Due to Forced Outages MW (1)	Hours In Month	Average Market Purchases (Non-Rockport) Assigned to Native Load Not Due to Forced Outages MW	Maximum Hourly Market Purchases (Non-Rockport) Assigned to Native Load Not Due to Forced Outages MW (2)	Hour in Which Maximum Market Purchases (Non-Rockport) Occurred MW (3)	Internal Load In Same Hour MW (4)	Non-Rockport $/MWh Purchase Power Cost In Same Hour (5)	Peaking Unit Equivalent $/MWh In Same Hour (6)
May-21	109,853.93	744	147.65	320.27	05/21 hour 13	669	$24.628	$63.848
June-21	63,321.88	720	87.95	395.57	06/23 hour 17	692	$26.042	$67.026
July-21	24,761.15	744	33.28	234.92	07/27 hour 08	580	$25.359	$75.168
August-21	33,391.88	744	44.88	265.50	08/08 hour 18	844	$68.411	$78.300
September-21	64,776.86	720	89.97	376.65	09/19 hour 11	598	$38.746	$87.144
October-21	213,045.65	744	286.35	658.19	10/27 hour 09	670	$66.552	$93.176

(1) Company's Response to Staff 1-16 Attachments 1-6, Monthly Hourly Purch Alloc Worksheet Tabs, Sum of Cell Column I.
(2) Company's Response to Staff 1-16 Attachments 1-6, Monthly Hourly Purch Alloc Worksheet Tabs, Highest Hourly MW in Cell Column I.
(3) Company's Response to Staff 1-16 Attachments 1-6, Monthly Hourly Purch Alloc Worksheet Tabs, Corresponding Hour in Column A to Highest Hourly MW.
(4) Company's Response to Staff 1-16 Attachments 1-6, Monthly Dated Tabs (First Tab in Each File), Corresponding Native Load MW Hour in Column N to Highest Hourly MW.
(5) Company's Response to Staff 1-16 Attachments 1-6, Monthly Hourly Purch Alloc Worksheet Tabs, $/ MWh of Purchases allocated to Internal Load.
(6) Company's Response to Staff 1-16 Attachments 1-6, Monthly Hourly Purch Alloc Worksheet Tabs, Peaking Unit Equivalent $/MWh.

KIUC-3

#9

KIUC Ex. 5

Kentucky Power Company
Fuel Adjustment Case No. 2022-00036
Generating Unit Outages
May 1, 2021-October 31, 2021

Unit Name	Event Type *	Event Start	Event End	Event Description
Big Sandy 1	PO	4/10/21 1:50 AM	5/8/21 7:00 AM	Planned Outage to replace #1315667
Big Sandy 1	MO	5/28/21 12:00 PM	6/2/21 2:34 PM	to repair steam leak under HP Turbine and to inspect East Air Heater Bull Gear
Big Sandy 1	MO	6/22/21 6:00 AM	6/28/21 12:00 AM	Boiler and governor valve inspection
Big Sandy 1	FO	6/28/21 12:00 AM	7/1/21 12:00 AM	Water wall tube leak repair
Big Sandy 1	MO	7/1/21 12:00 AM	7/4/21 9:13 PM	to repair and replace Waterwall tubes on rear wall. X-rays show indications that will require replacement. Scaffold is already in place for current repairs. Replace gasket on Reheat isolation device.
Big Sandy 1	MO	7/31/21 12:00 AM	8/7/21 7:00 AM	Boiler i/r
Big Sandy 1	MO	8/14/21 12:40 AM	8/21/21 6:51 AM	Boiler i/r, clean the Main and Auxiliary Condensers and service the East and West Air Compressors.
Big Sandy 1	MO	8/29/21 12:00 AM	9/4/21 7:00 AM	to repair steam leak on lower left Reheat Line
Big Sandy 1	MO	9/23/21 1:45 AM	10/8/21 10:00 PM	Boiler i/r, repair steam leak between RV-309 and the Lower Right RH steam line, repair #5 North HP Heater leak.
Big Sandy 1	PO	10/8/21 10:00 PM	12/21/21 7:47 AM	GBIR, GBIR, Turbine Exhaust High Energy Piping (HEP) inspections, Boiler corrosion fatigue inspections, Main and Aux Condenser eddy current testing, and Cooling Tower repairs.
Mitchell 1	FO	4/9/21 8:29 PM	6/5/21 3:00 PM	Main transformer outage
Mitchell 1	FO	6/5/21 3:00 PM	6/6/21 7:32 PM	Leak on East H2 seal oil cooler
Mitchell 1	MO	7/16/21 2:14 AM	7/23/21 11:01 PM	Repair 11 ID Fan Pitch Blade Operator, install 11A Circulating Water Pump, Boiler i/r.
Mitchell 1	FO	8/3/21 9:40 PM	8/8/21 9:28 PM	Tube Leak
Mitchell 1	FO	8/23/21 6:18 PM	9/1/21 7:58 PM	Tube Leak
Mitchell 1	FO	9/16/21 2:35 AM	9/21/21 12:00 AM	Tube Leak
Mitchell 1	FO	9/21/21 10:46 AM	9/23/21 8:44 AM	Steam leak.
Mitchell 1	FO	9/27/21 4:55 PM	10/2/21 9:30 AM	Loss of Air Heater
Mitchell 1	FO	10/5/21 10:37 PM	10/6/21 6:50 PM	Under Excitation trip
Mitchell 1	MO	10/8/21 12:00 AM	10/8/21 1:46 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	MO	10/8/21 1:46 AM	10/8/21 8:17 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	MO	10/8/21 8:17 AM	10/8/21 8:27 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	MO	10/8/21 8:27 AM	10/8/21 8:28 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	MO	10/8/21 8:28 AM	10/8/21 8:33 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	MO	10/8/21 8:33 AM	10/8/21 8:35 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	MO	10/8/21 8:35 AM	10/16/21 12:00 AM	Boiler i/r; FGD repairs; ID Fan Pilot Valve inspections.
Mitchell 1	PO	10/16/21 12:00 AM	12/12/21 1:31 PM	Boiler i/r, BOP repairs, SCR Catalyst #4 layer replacement, Boiler Feed Pump Element replacement.
Mitchell 1	MO	12/19/21 7:00 AM	12/23/21 8:32 AM	to dewater cooling tower and install 11B Circulating Water Pump
Mitchell 2	MO	6/24/21 12:00 AM	6/26/21 12:00 AM	Boiler Hydro, I/R
Mitchell 2	MO	6/26/21 12:00 AM	7/4/21 4:15 AM	to repair Precipitator Inlet Duct and internal inspection, drain FGD Absorber to repair an Agitator Seal and level probe B"
Mitchell 2	MO	9/4/21 1:54 AM	9/13/21 2:29 AM	Repair 22 ID fan pitch blade issuePatch leaks in precipitator duct. Boiler upper fill valve repairBoiler Hydro inspect and repair.
Mitchell 2	MO	10/22/21 12:00 AM	11/6/21 9:54 AM	Boiler i/r, UMO-803 i/r, Dry Fly Ash repairs, FGD repairs, FMO-101 i/r, #1 Control Valve EHC line i/r.

Event Type *

FO Forced Outage
MO Maintenance Outage
PO Planned Outage
Note: i/r = inspection and repair

KIUC-5

Kentucky Power Company
Fuel Adjustment Case No. 2022-00036
Generating Unit Outages
May 1, 2021-October 31, 2021

Unit Name	Event Type *	Event Start	Event End	Event Description
Rockport 1	MO	7/18/21 2:50 AM	7/19/21 11:34 AM	Repair Boiler Ash Hopper door
Rockport 1	MO	7/30/21 3:14 AM	8/5/21 11:21 PM	Boiler i/r
Rockport 1	FO	8/19/21 5:30 AM	8/20/21 2:13 PM	11C Auxiliary Transformer Overall Differential Trip
Rockport 1	MO	8/21/21 12:00 AM	8/25/21 11:20 AM	Repair Ash Hopper Door #223, Boiler i/r, Boiler Duct Ash removal, Clean Circ. Water Pump Screens
Rockport 1	MO	8/30/21 5:52 AM	9/11/21 12:00 AM	Boiler i/r and duct ash removal; 13.8 Kv Transformer 11C i/r; Pulverizer repairs
Rockport 1	PO	9/11/21 12:00 AM	12/15/21 2:00 PM	General Boiler i/r
Rockport 2	MO	4/15/21 11:00 PM	6/1/21 4:00 PM	DSI Injection System piping upgrade, BOP i/r.
Rockport 2	MO	6/15/21 1:51 PM	6/23/21 7:21 PM	Boiler i/r, Ash Removal, Hydro & RSH/SSH Air Test and to install SCR Heaters.
Rockport 2	MO	9/7/21 4:41 AM	10/9/21 12:00 AM	Boiler I/R, boiler duct ash removal, deslag boiler, generator stator tank hydrogen leak repair, #10 pulverizer tempering air and fuel output damper repair, #4 clinker grinder repair, economizer ash hopper repairs.
Rockport 2	PO	10/9/21 12:00 AM	11/30/21 2:50 PM	General Boiler i/r

Event Type *

FO	Forced Outage
MO	Maintenance Outage
PO	Planned Outage
Note:	i/r = inspection and repair

2

PLANT	EVENT START	EVENT END	HOURS OFFLINE FOR FORCED, PLANNED, AND MAINTENANCE OUTAGES						
				MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER
Big Sandy 1									
	04/10/2021 1:50 A.M.	5/8/2021 7:00:00 A.M.		175					
	5/28/2021 12:00:00 P.M.	06/02/2021 2:34 P.M.		84	38.5				
	06/22/2021 6:00 A.M.	06/28/2021 12:00 A.M.			138				
	07/01/2021 12:00 A.M.	07/04/2021 9:13 P.M.				93.25			
	07/31/2021 12:00 A.M.	8/7/2021 7:00 A.M.				24	151		
	8/14/2021 12:40 A.M.	08/21/2021 6:51 A.M.					174.25		
	08/29/2021 12:00 A.M.	09/04/2021 7:00 A.M.					72	79	
	09/23/2021 1:45 A.M.	10/08/2021 10:00 P.M.						190	190
	10/08/2021 10:00 P.M.	12/21/2021 7:47 A.M.							554
			TOTAL	**259**	**176.5**	**117.25**	**397.25**	**269**	**744**
Mitchell 1									
	04/09/2021 8:29 P.M.	06/05/2021 3:00 P.M.		744	111				
	06/05/2021 3:00 P.M.	06/06/2021 7:32 P.M.			28.5				
	07/16/2021 2:14 A.M.	07/23/2021 11:01 P.M.				188.75			
	8/3/2021 9:40 P.M.	08/08/2021 9:28 P.M.					120		
	08/23/2021 6:18 P.M.	09/01/2021 7:58 P.M.					197.75	20	
	09/16/2021 2:35 A.M.	09/21/2021 12:00 A.M.						117.25	
	09/21/2021 10:46 A.M.	09/23/2021 8:44 A.M.						46	
	09/27/2021 4:55 P.M.	10/02/2021 9:30 A.M.						79	33.5
	10/05/2021 10:37 P.M.	10/06/2021 6:50 P.M.							20.25
	10/08/2021 12:00 A.M.	10/08/2021 1:46 A.M.							1.75
	10/08/2021 1:46 A.M.	10/08/2021 8:17 A.M.							6.5
	10/08/2021 8:17 A.M.	10/08/2021 8:27 A.M.							0.1
	10/08/2021 8:27 A.M.	10/08/2021 8:28 A.M.							0.01
	10/08/2021 8:28 A.M.	10/08/2021 8:33 A.M.							0.05
	10/08/2021 8:33 A.M.	10/08/2021 8:35 A.M.							0.02
	10/08/2021 8:35 A.M.	10/16/2021 12:00 A.M.							183.25
	10/16/2021 12:00 A.M.	12/12/2021 1:31 P.M.							384
			TOTAL	**744**	**139.5**	**188.75**	**317.75**	**262.25**	**629.43**
Mitchell 2									
	06/24/2021 12:00 A.M.	06/26/2021 12:00 A.M.			48				
	06/26/2021 12:00 A.M.	7/4/2021 4:15 A.M.			120	76.25			
	09/04/2021 1:54 A.M.	09/13/2021 2:29 A.M.						216.5	
	10/22/2021 12:00 A.M.	11/06/20221 9:54 A.M.							240
			TOTAL		**168**	**76.25**		**216.5**	**240**
Rockport 1									
	07/18/2021 2:50 A.M.	07/19/2021 11:34 A.M.				32.75			
	07/30/2021 3:14 A.M.	08/05/2021 11:21 P.M.				44.75	119.25		
	08/19/2021 5:30 A.M.	08/20/2021 2:13 P.M.					32.75		
	08/21/2021 12:00 A.M.	08/25/2021 11:20 A.M.					107.25		
	08/30/2021 5:52 A.M.	09/11/2021 12:00 A.M.					42	240	
	09/11/2021 12:00 A.M.	12/15/2021 2:00 P.M.						480	744
			TOTAL			**77.5**	**301.25**	**720**	**744**
Rockport 2									
	04/15/2021 11:00 P.M.	06/01/2021 4:00 P.M.		744	16				
	06/15/2021 1:51 P.M.	06/23/2021 7:21 P.M.			197.5				
	09/07/2021 4:41 A.M.	10/09/2021 12:00 A.M.						571.25	192
	10/09/2021 12:00 A.M.	11/30/2021 2:50 P.M.							552
			TOTAL	**744**	**213.5**			**571.25**	**744**

Source: Response to Staff 1-15 and KIUC 2-5

Kentucky Power Company
Availability and Generation by Unit Factoring In All Known Outages
October 2021

	Capability MW	October 2021
Hours in Month		744
Average Cost of Purchases Assigned to Native Load ($/MWh)		$57.37
Purchases Assigned to Native Load (MWh)		225,252
Generation Costs ($/MWh)		
Big Sandy 1		-
Mitchell 1		$30.01
Mitchell 2		$20.74
Rockport 1		-
Rockport 2		-
Hours Offline For Outages		
Big Sandy 1		744
Mitchell 1		629.43
Mitchell 2		240
Rockport 1		744
Rockport 2		744
Hours Available for Generation		
Big Sandy 1		0
Mitchell 1		114.57
Mitchell 2		504
Rockport 1		0
Rockport 2		0
Maximum Generation for Available Hours (MWh)		
Big Sandy 1	295	-
Mitchell 1	385	44,109
Mitchell 2	395	199,080
Rockport 1	198	-
Rockport 2	195	-
Actual Generation (MWh)		
Big Sandy 1		-
Mitchell 1		27,613
Mitchell 2		133,877
Rockport 1		-
Rockport 2		-
Net Output Factor (Generation During Available Hours)		
Big Sandy 1		-
Mitchell 1		63%
Mitchell 2		67%
Rockport 1		-
Rockport 2		-

Source Data: Attachments included in Response to Staff 1-15, Staff 1-16 and KIUC 2-5.

4

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/01/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/01/2021 23:00	38.00	38.87
10/01/2021 22:00	43.25	44.38
10/01/2021 21:00	46.85	48.08
10/01/2021 20:00	53.66	55.02
10/01/2021 19:00	61.45	64.73
10/01/2021 18:00	63.83	68.81
10/01/2021 17:00	71.79	77.22
10/01/2021 16:00	67.09	72.45
10/01/2021 15:00	63.43	68.06
10/01/2021 14:00	60.91	63.94
10/01/2021 13:00	56.91	59.15
10/01/2021 12:00	57.67	59.31
10/01/2021 11:00	51.30	52.76
10/01/2021 10:00	48.17	49.54
10/01/2021 09:00	48.46	49.79
10/01/2021 08:00	48.05	49.38
10/01/2021 07:00	49.78	51.05
10/01/2021 06:00	45.67	46.79
10/01/2021 05:00	35.41	36.22
10/01/2021 04:00	33.65	34.33
10/01/2021 03:00	33.22	33.87
10/01/2021 02:00	33.39	34.06
10/01/2021 01:00	34.24	34.98
10/01/2021 00:00	36.47	37.25

Hourly data is displayed in prevailing time, which includes an annual daylight savings adjustment, as follows: ISO-NE, NYISO, PJM, MISO, Ontario use Eastern Time; ERCOT and SPP use Central Time; Alberta uses Mountain Time. To view more than one day or to adjust displayed time zone, click into Advanced Charting or export data to the Excel Add-In and adjust the time zone setting. Daily, monthly, and annual peak prices assume the following definitions: Peak hours include IESO, NYISO, ISO-NE, PJM hour beginning (HB) 7 – 22, M - F, ET (prevailing); MISO HB 6 – 21, M - F, year round EST; ERCOT, SPP HB 6 – 21, M - F, CT (prevailing); CAISO HB 6 – 21, M - Sat, PT (prevailing); AESO HB 7 – 22, M - Sun, MT (prevailing). All other hours are considered off-peak. The NERC holiday calendar is followed. See Help documentation for further details.

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/02/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/02/2021 23:00	40.29	41.14
10/02/2021 22:00	45.38	46.44
10/02/2021 21:00	51.10	52.25
10/02/2021 20:00	58.80	60.16
10/02/2021 19:00	65.48	67.10
10/02/2021 18:00	68.18	69.97
10/02/2021 17:00	75.08	77.22
10/02/2021 16:00	67.45	69.36
10/02/2021 15:00	63.66	65.40
10/02/2021 14:00	60.73	62.35
10/02/2021 13:00	56.12	57.55
10/02/2021 12:00	50.05	51.37
10/02/2021 11:00	45.47	46.68
10/02/2021 10:00	43.74	44.93
10/02/2021 09:00	44.98	46.08
10/02/2021 08:00	41.57	42.52
10/02/2021 07:00	41.35	42.29
10/02/2021 06:00	36.91	37.72
10/02/2021 05:00	35.74	36.47
10/02/2021 04:00	34.62	35.25
10/02/2021 03:00	34.41	35.03
10/02/2021 02:00	35.80	36.42
10/02/2021 01:00	37.69	38.34
10/02/2021 00:00	41.17	41.94

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/03/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/03/2021 23:00	43.23	44.13
10/03/2021 22:00	51.01	52.01
10/03/2021 21:00	58.32	59.55
10/03/2021 20:00	68.38	69.81
10/03/2021 19:00	79.20	80.90
10/03/2021 18:00	78.32	79.96
10/03/2021 17:00	79.82	81.36
10/03/2021 16:00	74.04	75.65
10/03/2021 15:00	71.86	73.56
10/03/2021 14:00	66.22	67.77
10/03/2021 13:00	62.74	64.11
10/03/2021 12:00	55.15	56.30
10/03/2021 11:00	49.27	50.27
10/03/2021 10:00	44.91	45.77
10/03/2021 09:00	41.43	42.12
10/03/2021 08:00	39.48	40.16
10/03/2021 07:00	38.55	39.17
10/03/2021 06:00	34.09	34.64
10/03/2021 05:00	33.09	33.58
10/03/2021 04:00	32.37	32.84
10/03/2021 03:00	32.68	33.16
10/03/2021 02:00	34.97	35.50
10/03/2021 01:00	37.63	38.25
10/03/2021 00:00	40.64	41.36

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/04/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/04/2021 23:00	48.70	49.64
10/04/2021 22:00	57.94	59.08
10/04/2021 21:00	68.48	69.84
10/04/2021 20:00	73.02	74.34
10/04/2021 19:00	88.70	90.88
10/04/2021 18:00	85.88	91.23
10/04/2021 17:00	94.15	98.64
10/04/2021 16:00	87.94	92.71
10/04/2021 15:00	83.80	87.31
10/04/2021 14:00	83.95	85.53
10/04/2021 13:00	82.30	83.84
10/04/2021 12:00	75.90	77.44
10/04/2021 11:00	78.61	80.22
10/04/2021 10:00	72.38	73.85
10/04/2021 09:00	69.84	71.20
10/04/2021 08:00	65.37	66.67
10/04/2021 07:00	68.38	69.79
10/04/2021 06:00	58.38	59.52
10/04/2021 05:00	43.16	43.97
10/04/2021 04:00	37.45	38.13
10/04/2021 03:00	34.95	35.60
10/04/2021 02:00	35.84	36.55
10/04/2021 01:00	40.19	41.00
10/04/2021 00:00	42.81	43.65

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S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/05/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/05/2021 23:00	52.62	53.47
10/05/2021 22:00	58.41	59.52
10/05/2021 21:00	67.05	68.33
10/05/2021 20:00	75.00	76.17
10/05/2021 19:00	84.95	86.61
10/05/2021 18:00	87.60	89.29
10/05/2021 17:00	93.83	95.52
10/05/2021 16:00	89.14	90.89
10/05/2021 15:00	84.80	86.57
10/05/2021 14:00	82.87	84.67
10/05/2021 13:00	77.23	78.74
10/05/2021 12:00	71.77	73.19
10/05/2021 11:00	69.97	71.37
10/05/2021 10:00	67.93	69.32
10/05/2021 09:00	64.63	66.05
10/05/2021 08:00	61.19	62.61
10/05/2021 07:00	60.91	62.10
10/05/2021 06:00	62.43	64.11
10/05/2021 05:00	53.80	54.79
10/05/2021 04:00	43.81	44.63
10/05/2021 03:00	42.21	43.01
10/05/2021 02:00	44.02	44.87
10/05/2021 01:00	49.11	50.02
10/05/2021 00:00	50.58	51.48

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/06/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/06/2021 23:00	54.34	55.27
10/06/2021 22:00	57.83	60.22
10/06/2021 21:00	67.43	69.81
10/06/2021 20:00	74.25	80.18
10/06/2021 19:00	91.17	92.64
10/06/2021 18:00	85.49	86.84
10/06/2021 17:00	92.79	94.05
10/06/2021 16:00	90.37	91.92
10/06/2021 15:00	81.76	83.72
10/06/2021 14:00	76.40	78.55
10/06/2021 13:00	75.22	77.04
10/06/2021 12:00	72.42	73.89
10/06/2021 11:00	67.30	69.00
10/06/2021 10:00	65.49	66.94
10/06/2021 09:00	62.94	67.87
10/06/2021 08:00	58.73	61.60
10/06/2021 07:00	60.40	63.60
10/06/2021 06:00	60.55	64.27
10/06/2021 05:00	46.97	50.08
10/06/2021 04:00	39.86	43.36
10/06/2021 03:00	38.55	42.10
10/06/2021 02:00	39.63	42.53
10/06/2021 01:00	44.53	47.40
10/06/2021 00:00	47.59	49.32

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/07/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/07/2021 23:00	54.86	56.37
10/07/2021 22:00	58.62	60.34
10/07/2021 21:00	68.26	70.30
10/07/2021 20:00	72.80	76.52
10/07/2021 19:00	86.74	91.80
10/07/2021 18:00	79.94	84.97
10/07/2021 17:00	90.67	94.69
10/07/2021 16:00	89.89	92.75
10/07/2021 15:00	82.03	85.09
10/07/2021 14:00	81.40	85.00
10/07/2021 13:00	82.30	85.08
10/07/2021 12:00	78.59	80.92
10/07/2021 11:00	74.57	76.06
10/07/2021 10:00	72.45	74.07
10/07/2021 09:00	70.15	71.83
10/07/2021 08:00	64.99	66.46
10/07/2021 07:00	68.60	70.18
10/07/2021 06:00	67.96	72.16
10/07/2021 05:00	52.63	55.58
10/07/2021 04:00	43.61	45.69
10/07/2021 03:00	41.25	43.31
10/07/2021 02:00	42.66	44.61
10/07/2021 01:00	46.94	48.98
10/07/2021 00:00	51.75	53.92

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S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/08/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/08/2021 23:00	51.96	53.29
10/08/2021 22:00	57.33	58.85
10/08/2021 21:00	62.19	63.74
10/08/2021 20:00	68.46	69.99
10/08/2021 19:00	74.59	76.28
10/08/2021 18:00	75.27	77.04
10/08/2021 17:00	84.04	85.71
10/08/2021 16:00	78.00	79.62
10/08/2021 15:00	76.53	78.27
10/08/2021 14:00	72.77	74.44
10/08/2021 13:00	70.87	72.72
10/08/2021 12:00	72.01	73.93
10/08/2021 11:00	68.46	70.30
10/08/2021 10:00	68.28	70.27
10/08/2021 09:00	67.28	68.89
10/08/2021 08:00	62.70	64.28
10/08/2021 07:00	67.80	69.43
10/08/2021 06:00	58.35	59.77
10/08/2021 05:00	48.69	49.75
10/08/2021 04:00	40.74	41.61
10/08/2021 03:00	39.09	39.91
10/08/2021 02:00	40.96	41.82
10/08/2021 01:00	43.89	44.87
10/08/2021 00:00	46.48	47.49

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S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/09/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/09/2021 23:00	40.77	41.34
10/09/2021 22:00	46.67	47.49
10/09/2021 21:00	51.39	52.43
10/09/2021 20:00	63.03	64.23
10/09/2021 19:00	69.89	71.22
10/09/2021 18:00	68.14	69.47
10/09/2021 17:00	70.14	71.81
10/09/2021 16:00	67.09	68.57
10/09/2021 15:00	62.21	64.18
10/09/2021 14:00	61.97	63.43
10/09/2021 13:00	60.66	62.40
10/09/2021 12:00	61.69	63.44
10/09/2021 11:00	61.72	63.45
10/09/2021 10:00	56.44	58.01
10/09/2021 09:00	55.95	57.56
10/09/2021 08:00	49.64	51.06
10/09/2021 07:00	47.19	48.50
10/09/2021 06:00	43.06	44.20
10/09/2021 05:00	40.27	41.18
10/09/2021 04:00	39.50	40.39
10/09/2021 03:00	39.21	40.10
10/09/2021 02:00	41.75	42.70
10/09/2021 01:00	47.56	48.69
10/09/2021 00:00	49.41	50.54

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/10/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/10/2021 23:00	43.50	43.96
10/10/2021 22:00	49.37	49.81
10/10/2021 21:00	61.18	61.69
10/10/2021 20:00	73.74	74.33
10/10/2021 19:00	81.86	82.95
10/10/2021 18:00	84.36	85.45
10/10/2021 17:00	81.42	82.69
10/10/2021 16:00	76.27	77.57
10/10/2021 15:00	76.26	77.37
10/10/2021 14:00	70.31	71.28
10/10/2021 13:00	63.82	64.89
10/10/2021 12:00	60.58	61.43
10/10/2021 11:00	57.42	58.21
10/10/2021 10:00	51.30	52.05
10/10/2021 09:00	45.94	46.47
10/10/2021 08:00	39.83	40.17
10/10/2021 07:00	38.84	38.76
10/10/2021 06:00	35.86	35.64
10/10/2021 05:00	33.22	32.94
10/10/2021 04:00	33.44	33.45
10/10/2021 03:00	33.54	33.54
10/10/2021 02:00	35.70	35.83
10/10/2021 01:00	36.89	37.01
10/10/2021 00:00	39.99	40.21

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/11/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/11/2021 23:00	43.20	42.92
10/11/2021 22:00	51.08	49.96
10/11/2021 21:00	60.93	59.77
10/11/2021 20:00	74.78	73.04
10/11/2021 19:00	82.90	81.71
10/11/2021 18:00	84.80	84.11
10/11/2021 17:00	88.73	88.08
10/11/2021 16:00	85.08	84.81
10/11/2021 15:00	79.57	79.34
10/11/2021 14:00	72.76	72.10
10/11/2021 13:00	69.04	68.48
10/11/2021 12:00	64.63	64.55
10/11/2021 11:00	62.13	62.49
10/11/2021 10:00	57.61	57.93
10/11/2021 09:00	52.65	53.08
10/11/2021 08:00	51.92	52.41
10/11/2021 07:00	50.48	51.06
10/11/2021 06:00	46.27	46.88
10/11/2021 05:00	38.15	38.65
10/11/2021 04:00	34.08	34.54
10/11/2021 03:00	32.12	32.55
10/11/2021 02:00	32.37	32.84
10/11/2021 01:00	34.57	35.08
10/11/2021 00:00	36.96	37.50

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/12/2021
Frequency: Hourly
Peak: Around the clock

Date	*AEP GEN HUB*	*AEP-DAYTON HUB*
10/12/2021 23:00	44.19	44.90
10/12/2021 22:00	50.88	51.61
10/12/2021 21:00	62.97	63.64
10/12/2021 20:00	74.28	75.32
10/12/2021 19:00	89.43	90.67
10/12/2021 18:00	85.57	86.90
10/12/2021 17:00	81.35	82.13
10/12/2021 16:00	76.85	77.38
10/12/2021 15:00	73.37	73.86
10/12/2021 14:00	73.88	74.35
10/12/2021 13:00	68.05	68.07
10/12/2021 12:00	67.86	67.71
10/12/2021 11:00	66.07	66.03
10/12/2021 10:00	66.56	66.89
10/12/2021 09:00	55.79	56.06
10/12/2021 08:00	52.39	52.74
10/12/2021 07:00	52.99	52.87
10/12/2021 06:00	52.13	51.67
10/12/2021 05:00	40.57	40.20
10/12/2021 04:00	35.29	34.92
10/12/2021 03:00	33.16	32.40
10/12/2021 02:00	33.90	33.12
10/12/2021 01:00	36.08	35.14
10/12/2021 00:00	37.09	35.79

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/13/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/13/2021 23:00	45.93	45.98
10/13/2021 22:00	51.35	51.67
10/13/2021 21:00	58.81	59.27
10/13/2021 20:00	69.42	69.56
10/13/2021 19:00	81.95	81.78
10/13/2021 18:00	82.80	82.22
10/13/2021 17:00	82.02	81.32
10/13/2021 16:00	76.37	75.58
10/13/2021 15:00	75.06	74.21
10/13/2021 14:00	70.57	70.38
10/13/2021 13:00	68.53	68.59
10/13/2021 12:00	66.86	67.64
10/13/2021 11:00	63.62	64.77
10/13/2021 10:00	60.41	61.60
10/13/2021 09:00	55.67	56.00
10/13/2021 08:00	53.69	54.23
10/13/2021 07:00	57.63	58.52
10/13/2021 06:00	54.42	55.00
10/13/2021 05:00	43.82	44.43
10/13/2021 04:00	39.20	39.70
10/13/2021 03:00	35.65	36.08
10/13/2021 02:00	36.54	36.96
10/13/2021 01:00	42.28	42.82
10/13/2021 00:00	44.11	44.63

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/14/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/14/2021 23:00	50.30	50.88
10/14/2021 22:00	61.46	62.00
10/14/2021 21:00	68.08	68.79
10/14/2021 20:00	75.11	76.00
10/14/2021 19:00	92.59	93.70
10/14/2021 18:00	90.52	91.51
10/14/2021 17:00	94.39	95.35
10/14/2021 16:00	88.09	88.88
10/14/2021 15:00	81.57	83.60
10/14/2021 14:00	78.45	80.22
10/14/2021 13:00	72.92	74.50
10/14/2021 12:00	71.52	72.64
10/14/2021 11:00	66.97	68.11
10/14/2021 10:00	64.57	65.97
10/14/2021 09:00	59.88	61.34
10/14/2021 08:00	58.81	60.00
10/14/2021 07:00	61.36	62.48
10/14/2021 06:00	58.46	59.41
10/14/2021 05:00	45.68	46.29
10/14/2021 04:00	39.16	39.67
10/14/2021 03:00	35.45	35.86
10/14/2021 02:00	35.90	36.34
10/14/2021 01:00	40.61	41.11
10/14/2021 00:00	42.54	43.02

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/15/2021
Frequency: Hourly
Peak: Around the clock

Date	*AEP GEN HUB*	*AEP-DAYTON HUB*
10/15/2021 23:00	49.19	48.69
10/15/2021 22:00	62.87	60.99
10/15/2021 21:00	67.64	65.72
10/15/2021 20:00	73.53	71.29
10/15/2021 19:00	86.80	84.13
10/15/2021 18:00	88.74	85.41
10/15/2021 17:00	96.80	92.65
10/15/2021 16:00	98.04	93.38
10/15/2021 15:00	90.01	87.05
10/15/2021 14:00	89.41	87.52
10/15/2021 13:00	84.73	83.88
10/15/2021 12:00	76.91	76.74
10/15/2021 11:00	78.33	78.89
10/15/2021 10:00	73.59	74.63
10/15/2021 09:00	71.32	72.77
10/15/2021 08:00	68.18	69.22
10/15/2021 07:00	72.05	73.08
10/15/2021 06:00	61.64	62.79
10/15/2021 05:00	48.32	49.06
10/15/2021 04:00	42.99	43.69
10/15/2021 03:00	39.79	40.41
10/15/2021 02:00	40.75	41.39
10/15/2021 01:00	45.59	46.32
10/15/2021 00:00	50.23	50.99

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/16/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/16/2021 23:00	36.87	37.07
10/16/2021 22:00	38.58	38.60
10/16/2021 21:00	45.33	45.73
10/16/2021 20:00	53.04	53.51
10/16/2021 19:00	58.30	58.29
10/16/2021 18:00	54.77	53.91
10/16/2021 17:00	52.43	50.29
10/16/2021 16:00	50.81	48.55
10/16/2021 15:00	49.86	47.51
10/16/2021 14:00	50.78	47.78
10/16/2021 13:00	51.46	48.38
10/16/2021 12:00	52.12	49.38
10/16/2021 11:00	52.92	51.30
10/16/2021 10:00	54.40	53.30
10/16/2021 09:00	52.47	51.63
10/16/2021 08:00	48.94	48.45
10/16/2021 07:00	47.17	46.83
10/16/2021 06:00	43.83	43.67
10/16/2021 05:00	40.66	40.36
10/16/2021 04:00	38.87	38.68
10/16/2021 03:00	38.73	38.42
10/16/2021 02:00	41.95	41.46
10/16/2021 01:00	46.47	46.07
10/16/2021 00:00	48.70	48.27

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/17/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/17/2021 23:00	38.68	38.54
10/17/2021 22:00	42.81	43.18
10/17/2021 21:00	50.33	50.83
10/17/2021 20:00	56.20	56.91
10/17/2021 19:00	67.41	68.23
10/17/2021 18:00	58.73	59.25
10/17/2021 17:00	47.61	47.90
10/17/2021 16:00	41.57	41.80
10/17/2021 15:00	38.83	39.02
10/17/2021 14:00	38.85	39.02
10/17/2021 13:00	40.02	40.14
10/17/2021 12:00	40.81	40.97
10/17/2021 11:00	41.61	41.88
10/17/2021 10:00	40.62	40.97
10/17/2021 09:00	39.00	39.39
10/17/2021 08:00	38.70	39.08
10/17/2021 07:00	36.75	37.09
10/17/2021 06:00	34.22	34.55
10/17/2021 05:00	33.60	33.37
10/17/2021 04:00	32.41	32.18
10/17/2021 03:00	32.38	32.00
10/17/2021 02:00	33.65	33.16
10/17/2021 01:00	34.76	34.23
10/17/2021 00:00	36.26	35.59

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/18/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/18/2021 23:00	47.99	48.68
10/18/2021 22:00	57.10	57.90
10/18/2021 21:00	63.19	64.19
10/18/2021 20:00	71.87	73.09
10/18/2021 19:00	83.78	85.30
10/18/2021 18:00	78.73	79.97
10/18/2021 17:00	69.91	70.80
10/18/2021 16:00	66.84	67.73
10/18/2021 15:00	61.12	61.92
10/18/2021 14:00	64.55	65.42
10/18/2021 13:00	63.65	64.51
10/18/2021 12:00	67.51	68.40
10/18/2021 11:00	69.77	70.73
10/18/2021 10:00	69.88	70.89
10/18/2021 09:00	73.69	75.36
10/18/2021 08:00	74.53	76.03
10/18/2021 07:00	75.63	77.07
10/18/2021 06:00	77.33	78.30
10/18/2021 05:00	52.25	52.82
10/18/2021 04:00	40.38	40.81
10/18/2021 03:00	36.38	36.77
10/18/2021 02:00	36.06	36.46
10/18/2021 01:00	36.05	36.45
10/18/2021 00:00	36.97	37.38

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/19/2021
Frequency: Hourly
Peak: Around the clock

Date	*AEP GEN HUB*	*AEP-DAYTON HUB*
10/19/2021 23:00	41.31	41.53
10/19/2021 22:00	46.02	46.46
10/19/2021 21:00	49.91	50.78
10/19/2021 20:00	62.07	63.37
10/19/2021 19:00	70.82	72.25
10/19/2021 18:00	67.43	68.76
10/19/2021 17:00	62.46	63.66
10/19/2021 16:00	60.10	61.39
10/19/2021 15:00	52.87	54.01
10/19/2021 14:00	54.65	55.87
10/19/2021 13:00	52.51	53.68
10/19/2021 12:00	54.92	56.12
10/19/2021 11:00	58.41	59.74
10/19/2021 10:00	57.02	58.26
10/19/2021 09:00	61.82	63.33
10/19/2021 08:00	64.27	65.86
10/19/2021 07:00	74.31	75.84
10/19/2021 06:00	69.82	71.23
10/19/2021 05:00	45.67	46.53
10/19/2021 04:00	35.74	36.25
10/19/2021 03:00	34.74	35.33
10/19/2021 02:00	34.70	35.17
10/19/2021 01:00	35.41	35.93
10/19/2021 00:00	39.12	39.74

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/20/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/20/2021 23:00	36.73	36.27
10/20/2021 22:00	41.47	40.95
10/20/2021 21:00	48.81	48.40
10/20/2021 20:00	55.75	55.60
10/20/2021 19:00	70.10	69.84
10/20/2021 18:00	67.43	66.84
10/20/2021 17:00	66.33	65.69
10/20/2021 16:00	58.34	58.44
10/20/2021 15:00	56.04	56.79
10/20/2021 14:00	56.41	57.54
10/20/2021 13:00	56.53	57.63
10/20/2021 12:00	56.00	57.12
10/20/2021 11:00	55.45	56.63
10/20/2021 10:00	54.58	55.73
10/20/2021 09:00	51.38	52.40
10/20/2021 08:00	57.26	58.41
10/20/2021 07:00	65.20	66.57
10/20/2021 06:00	59.75	60.82
10/20/2021 05:00	41.61	42.19
10/20/2021 04:00	33.82	34.26
10/20/2021 03:00	32.73	33.13
10/20/2021 02:00	32.99	33.33
10/20/2021 01:00	34.02	34.45
10/20/2021 00:00	36.99	37.42

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/21/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/21/2021 23:00	40.66	41.28
10/21/2021 22:00	45.32	45.99
10/21/2021 21:00	53.46	54.39
10/21/2021 20:00	58.90	59.97
10/21/2021 19:00	73.23	74.56
10/21/2021 18:00	67.03	68.03
10/21/2021 17:00	66.48	66.97
10/21/2021 16:00	57.98	58.18
10/21/2021 15:00	55.81	56.09
10/21/2021 14:00	55.41	55.31
10/21/2021 13:00	54.05	54.04
10/21/2021 12:00	53.60	53.49
10/21/2021 11:00	50.79	51.01
10/21/2021 10:00	47.77	47.85
10/21/2021 09:00	47.45	47.23
10/21/2021 08:00	50.04	49.73
10/21/2021 07:00	52.91	52.61
10/21/2021 06:00	47.15	46.85
10/21/2021 05:00	35.92	35.67
10/21/2021 04:00	30.59	30.39
10/21/2021 03:00	29.01	28.82
10/21/2021 02:00	28.95	28.52
10/21/2021 01:00	30.41	29.96
10/21/2021 00:00	31.36	31.02

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/22/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/22/2021 23:00	51.78	52.68
10/22/2021 22:00	57.74	58.82
10/22/2021 21:00	60.91	62.19
10/22/2021 20:00	63.93	65.23
10/22/2021 19:00	71.98	73.36
10/22/2021 18:00	66.77	67.92
10/22/2021 17:00	68.82	69.89
10/22/2021 16:00	63.13	64.13
10/22/2021 15:00	66.32	67.53
10/22/2021 14:00	62.33	63.42
10/22/2021 13:00	65.44	66.57
10/22/2021 12:00	68.40	69.53
10/22/2021 11:00	70.03	71.19
10/22/2021 10:00	70.75	71.96
10/22/2021 09:00	67.93	69.01
10/22/2021 08:00	67.32	68.40
10/22/2021 07:00	71.74	73.26
10/22/2021 06:00	61.77	62.91
10/22/2021 05:00	47.80	48.56
10/22/2021 04:00	43.78	44.36
10/22/2021 03:00	40.33	40.86
10/22/2021 02:00	40.62	41.13
10/22/2021 01:00	44.02	44.59
10/22/2021 00:00	45.27	45.87

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/23/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/23/2021 23:00	51.24	52.43
10/23/2021 22:00	57.34	58.63
10/23/2021 21:00	63.55	64.98
10/23/2021 20:00	67.75	69.24
10/23/2021 19:00	77.11	78.85
10/23/2021 18:00	74.73	76.32
10/23/2021 17:00	66.56	67.87
10/23/2021 16:00	55.60	56.70
10/23/2021 15:00	52.40	53.57
10/23/2021 14:00	52.02	53.19
10/23/2021 13:00	54.06	55.31
10/23/2021 12:00	62.71	64.31
10/23/2021 11:00	65.16	66.85
10/23/2021 10:00	66.30	68.06
10/23/2021 09:00	62.97	64.54
10/23/2021 08:00	62.24	63.78
10/23/2021 07:00	61.76	63.18
10/23/2021 06:00	51.38	52.48
10/23/2021 05:00	47.20	48.16
10/23/2021 04:00	43.93	44.75
10/23/2021 03:00	43.47	44.31
10/23/2021 02:00	45.13	45.95
10/23/2021 01:00	48.26	49.10
10/23/2021 00:00	52.11	52.99

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/24/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/24/2021 23:00	42.80	42.36
10/24/2021 22:00	46.26	46.01
10/24/2021 21:00	54.92	55.04
10/24/2021 20:00	65.18	64.96
10/24/2021 19:00	70.79	70.78
10/24/2021 18:00	70.30	69.82
10/24/2021 17:00	67.02	66.70
10/24/2021 16:00	53.65	53.47
10/24/2021 15:00	49.36	49.59
10/24/2021 14:00	48.13	48.50
10/24/2021 13:00	47.41	47.89
10/24/2021 12:00	48.33	49.18
10/24/2021 11:00	48.27	49.27
10/24/2021 10:00	47.82	48.84
10/24/2021 09:00	46.06	47.03
10/24/2021 08:00	45.67	46.70
10/24/2021 07:00	45.00	45.99
10/24/2021 06:00	41.58	42.41
10/24/2021 05:00	40.10	40.85
10/24/2021 04:00	38.29	38.99
10/24/2021 03:00	38.54	39.26
10/24/2021 02:00	41.75	42.53
10/24/2021 01:00	44.46	45.30
10/24/2021 00:00	47.41	48.38

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/25/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/25/2021 23:00	49.52	49.44
10/25/2021 22:00	57.88	57.68
10/25/2021 21:00	63.48	63.44
10/25/2021 20:00	69.07	69.62
10/25/2021 19:00	80.16	80.57
10/25/2021 18:00	85.76	85.06
10/25/2021 17:00	78.60	77.18
10/25/2021 16:00	70.53	69.33
10/25/2021 15:00	70.06	68.14
10/25/2021 14:00	70.20	68.66
10/25/2021 13:00	70.63	68.85
10/25/2021 12:00	75.18	74.28
10/25/2021 11:00	69.47	68.78
10/25/2021 10:00	67.66	67.89
10/25/2021 09:00	68.01	67.91
10/25/2021 08:00	63.60	63.92
10/25/2021 07:00	67.71	67.87
10/25/2021 06:00	64.98	64.70
10/25/2021 05:00	45.38	44.48
10/25/2021 04:00	37.85	37.22
10/25/2021 03:00	35.41	35.12
10/25/2021 02:00	35.44	34.95
10/25/2021 01:00	36.82	36.40
10/25/2021 00:00	39.08	38.72

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/26/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/26/2021 23:00	47.81	48.38
10/26/2021 22:00	53.83	54.50
10/26/2021 21:00	62.76	63.54
10/26/2021 20:00	68.30	69.10
10/26/2021 19:00	76.23	77.10
10/26/2021 18:00	83.20	83.95
10/26/2021 17:00	73.77	74.44
10/26/2021 16:00	66.83	67.47
10/26/2021 15:00	64.39	64.98
10/26/2021 14:00	66.78	67.42
10/26/2021 13:00	67.25	67.88
10/26/2021 12:00	68.86	69.65
10/26/2021 11:00	68.13	68.95
10/26/2021 10:00	69.08	69.94
10/26/2021 09:00	68.45	69.27
10/26/2021 08:00	66.67	67.55
10/26/2021 07:00	70.97	71.80
10/26/2021 06:00	63.15	63.52
10/26/2021 05:00	46.91	47.07
10/26/2021 04:00	39.28	39.20
10/26/2021 03:00	37.00	36.92
10/26/2021 02:00	37.53	37.28
10/26/2021 01:00	39.39	38.87
10/26/2021 00:00	44.17	43.46

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/27/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/27/2021 23:00	43.13	43.02
10/27/2021 22:00	46.36	46.22
10/27/2021 21:00	53.13	52.98
10/27/2021 20:00	58.88	58.92
10/27/2021 19:00	65.45	65.82
10/27/2021 18:00	69.10	69.32
10/27/2021 17:00	74.58	70.67
10/27/2021 16:00	58.74	56.97
10/27/2021 15:00	59.38	57.68
10/27/2021 14:00	58.99	57.87
10/27/2021 13:00	58.91	57.60
10/27/2021 12:00	64.85	63.04
10/27/2021 11:00	63.35	63.98
10/27/2021 10:00	67.22	68.05
10/27/2021 09:00	67.57	68.30
10/27/2021 08:00	68.19	69.23
10/27/2021 07:00	80.89	81.98
10/27/2021 06:00	71.57	71.82
10/27/2021 05:00	51.76	52.09
10/27/2021 04:00	46.47	46.93
10/27/2021 03:00	41.89	42.32
10/27/2021 02:00	42.85	43.27
10/27/2021 01:00	43.80	44.19
10/27/2021 00:00	45.48	45.88

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/28/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/28/2021 23:00	48.02	48.41
10/28/2021 22:00	53.42	53.90
10/28/2021 21:00	61.60	62.24
10/28/2021 20:00	68.58	69.31
10/28/2021 19:00	75.85	76.84
10/28/2021 18:00	83.41	84.36
10/28/2021 17:00	74.25	74.58
10/28/2021 16:00	70.19	70.26
10/28/2021 15:00	68.35	68.46
10/28/2021 14:00	67.94	68.44
10/28/2021 13:00	68.60	69.07
10/28/2021 12:00	71.42	71.88
10/28/2021 11:00	68.86	70.16
10/28/2021 10:00	71.23	72.49
10/28/2021 09:00	69.32	70.73
10/28/2021 08:00	72.45	73.64
10/28/2021 07:00	79.16	80.07
10/28/2021 06:00	72.05	72.09
10/28/2021 05:00	53.80	53.76
10/28/2021 04:00	45.68	45.65
10/28/2021 03:00	41.36	41.43
10/28/2021 02:00	43.73	43.90
10/28/2021 01:00	45.21	45.39
10/28/2021 00:00	46.87	46.98

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/29/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/29/2021 23:00	47.07	45.40
10/29/2021 22:00	50.22	48.00
10/29/2021 21:00	56.39	54.04
10/29/2021 20:00	64.11	61.37
10/29/2021 19:00	69.27	66.52
10/29/2021 18:00	77.50	74.75
10/29/2021 17:00	68.74	66.18
10/29/2021 16:00	63.96	61.68
10/29/2021 15:00	63.70	62.11
10/29/2021 14:00	63.92	62.82
10/29/2021 13:00	68.36	67.60
10/29/2021 12:00	67.78	67.54
10/29/2021 11:00	66.62	66.65
10/29/2021 10:00	67.47	67.41
10/29/2021 09:00	67.02	67.23
10/29/2021 08:00	65.93	65.83
10/29/2021 07:00	70.26	70.19
10/29/2021 06:00	55.32	54.70
10/29/2021 05:00	44.71	44.66
10/29/2021 04:00	39.17	39.22
10/29/2021 03:00	38.02	38.04
10/29/2021 02:00	38.32	38.66
10/29/2021 01:00	39.74	40.09
10/29/2021 00:00	42.83	43.17

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/30/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/30/2021 23:00	50.27	50.72
10/30/2021 22:00	58.55	59.06
10/30/2021 21:00	63.37	63.92
10/30/2021 20:00	68.18	68.96
10/30/2021 19:00	79.28	80.41
10/30/2021 18:00	81.83	82.99
10/30/2021 17:00	71.52	72.34
10/30/2021 16:00	66.15	66.80
10/30/2021 15:00	60.33	61.02
10/30/2021 14:00	60.22	61.00
10/30/2021 13:00	62.97	63.80
10/30/2021 12:00	67.33	68.32
10/30/2021 11:00	66.89	67.90
10/30/2021 10:00	67.31	68.26
10/30/2021 09:00	65.80	66.78
10/30/2021 08:00	61.69	62.63
10/30/2021 07:00	58.25	59.10
10/30/2021 06:00	50.99	50.72
10/30/2021 05:00	48.64	48.48
10/30/2021 04:00	47.30	46.61
10/30/2021 03:00	47.48	46.79
10/30/2021 02:00	48.07	47.27
10/30/2021 01:00	50.08	49.25
10/30/2021 00:00	53.01	52.06

S&P Capital IQ

ISO Day-Ahead Prices (Data)

Region: PJM
As Of: 10/31/2021
Frequency: Hourly
Peak: Around the clock

Date	AEP GEN HUB	AEP-DAYTON HUB
10/31/2021 23:00	49.03	48.35
10/31/2021 22:00	53.34	52.76
10/31/2021 21:00	63.07	62.49
10/31/2021 20:00	71.46	71.04
10/31/2021 19:00	76.26	74.77
10/31/2021 18:00	73.71	71.52
10/31/2021 17:00	62.86	59.92
10/31/2021 16:00	52.69	49.96
10/31/2021 15:00	51.01	48.51
10/31/2021 14:00	50.62	48.39
10/31/2021 13:00	50.85	48.76
10/31/2021 12:00	51.54	50.12
10/31/2021 11:00	52.75	52.05
10/31/2021 10:00	53.10	52.43
10/31/2021 09:00	52.27	51.66
10/31/2021 08:00	51.10	51.26
10/31/2021 07:00	49.32	49.83
10/31/2021 06:00	48.49	48.78
10/31/2021 05:00	49.32	49.59
10/31/2021 04:00	45.97	46.29
10/31/2021 03:00	47.84	48.21
10/31/2021 02:00	49.42	49.77
10/31/2021 01:00	49.83	50.19
10/31/2021 00:00	55.33	55.70

#10

KIUC Ex. 4

Kentucky Power Company
October 2021 Selected Data

Month	Sum of Native Load MWh for All Hours in Month (1)	Hours in Month	Average Hourly Native Load MW	Total Dispatched Generation MWh for All Hours in Month (2)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load MWh (3)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load $ (4)	Average Cost of Market Purchases (Non-Rockport) Assigned to Native Load $/MWh (5)	Average Peaking Unit Equivalent $/MWh (6)	PUE FAC Disallowance $ (7)
October	385,394	744	518.0	161,490	225,252	$ 12,923,530	$ 57.37	$ 86.49	$ 29,766

Generating Unit	Dispatched Generation MWh (8)	KPCO Capability MW (9)	Max Generation for Month MWh	Capacity Factor	Average Cost per MWh (10)	Forced Outages MWh (11)	Fuel Costs Assigned During Forced Outages $ (12)	Purchase Costs Substituted During Forced Outages $ (13)	Forced Outage Replacement Costs Removed From FAC $ (14)
Big Sandy 1	0	295	219,480	0%	$ -				
Mitchell 1	27,613	385	286,440	10%	$ 30.01	12,206	$ 366,361	$ 717,832	$ 351,471
Mitchell 2	133,877	395	293,880	46%	$ 20.74				
Rockport 1	0	198	147,312	0%	$ -				
Rockport 2	0	195	145,080	0%	$ -				
Total	161,490	1,468	1,092,192	15%		12,206	$ 366,361	$ 717,832	$ 351,471

(1) Company's Response to Staff 1-16 Attachment 6, 10-2021 Worksheet Tab, Cell N756
(2) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3. Matches FAC page 3 of 5.
(3) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cell F750
(4) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cell G750
(5) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cell G754
(6) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Average of Cell Column L
(7) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cell T750, Matches FAC Final Fuel Cost Schedule for October 2021 Actual Results Filed with November 2021 Estimated Fuel Costs page 5 of 5
(8) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3
(9) Company's Response to Staff 1-16 Attachment 6, 10-21 KPCo Gen Data Worksheet Tab
(10) Company's Response to Staff 1-16 Attachment 6, 10-21 Hourly Purch Alloc Worksheet Tab, Cell Columns M through Q
(11) Company's Response to Staff 1-16 Attachment 6, 10-2021 Worksheet Tab, Cell R757, Matches FAC Final Fuel Cost Schedule
(12) Company's Response to Staff 1-16 Attachment 6, 10-2021 Worksheet Tab, Cell AA757, Matches FAC Final Fuel Cost Schedule
(13) Company's Response to Staff 1-16 Attachment 6, 10-2021 Worksheet Tab, Cell V757, Matches FAC Final Fuel Cost Schedule
(14) Company's Response to Staff 1-16 Attachment 6, 10-2021 Worksheet Tab, Cell AB757, Matches FAC Final Fuel Cost Schedule

KIUC-4

Kentucky Power Company
September 2021 Selected Data

Month	Sum of Native Load MWh for All Hours in Month (1)	Hours in Month	Average Hourly Native Load MW	Total Dispatched Generation MWh for All Hours in Month (2)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load MWh (3)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load $ (4)	Average Cost of Market Purchases (Non-Rockport) Assigned to Native Load $/MWh (5)	Average Peaking Unit Equivalent $/MWh (6)	PUE FAC Disallowance $ (7)
September	425,394	720	590.8	365,342	91,050	$ 4,209,361	$ 46.23	$ 82.86	$ 32,806

Generating Unit	Dispatched Generation MWh (8)	KPCO Capability MW (9)	Max Generation for Month MWh	Capacity Factor	Average Cost per MWh (10)	Forced Outages MWh (11)	Fuel Costs Assigned During Forced Outages $ (12)	Purchase Costs Substituted During Forced Outages $ (13)	Forced Outage Replacement Costs Removed From FAC $ (14)
Big Sandy 1	65,375	295	212,400	31%	$ 54.97				
Mitchell 1	130,815	385	277,200	47%	$ 25.69	26,273	$ 674,926	$ 1,664,353	$ 989,427
Mitchell 2	157,126	395	284,400	55%	$ 22.43				
Rockport 1	0	198	142,560	0%	$ -				
Rockport 2	12,025	195	140,400	9%	$ 33.53				
Total	365,342	1,468	1,056,960	35%		26,273	$ 674,926	$ 1,664,353	$ 989,427

(1) Company's Response to Staff 1-16 Attachment 5, 09-2021 Worksheet Tab, Cell N732
(2) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3 and 09-2021 Worksheet Tab, Cell L732
(3) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cell F726
(4) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cell G726
(5) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cell G730
(6) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Average of Cell Column L
(7) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cell T726, Matches FAC Final Fuel Cost Schedule for September 2021 Actual Results Filed with October 2021 Estimated Fuel Costs page 5 of 5
(8) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3
(9) Company's Response to Staff 1-16 Attachment 5, 09-21 KPCo Gen Data Worksheet Tab
(10) Company's Response to Staff 1-16 Attachment 5, 09-21 Hourly Purch Alloc Worksheet Tab, Cell Columns M through Q
(11) Company's Response to Staff 1-16 Attachment 5, 09-2021 Worksheet Tab, Cell R733, Matches FAC Final Fuel Cost Schedule
(12) Company's Response to Staff 1-16 Attachment 5, 09-2021 Worksheet Tab, Cell AA733, Matches FAC Final Fuel Cost Schedule
(13) Company's Response to Staff 1-16 Attachment 5, 09-2021 Worksheet Tab, Cell V733, Matches FAC Final Fuel Cost Schedule
(14) Company's Response to Staff 1-16 Attachment 5, 09-2021 Worksheet Tab, Cell AB733, Matches FAC Final Fuel Cost Schedule

2

Kentucky Power Company
August 2021 Selected Data

Month	Sum of Native Load MWh for All Hours in Month (1)	Hours in Month	Average Hourly Native Load MW	Total Dispatched Generation MWh for All Hours in Month (2)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load MWh (3)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load $ (4)	Average Cost of Market Purchases (Non-Rockport) Assigned to Native Load $/MWh (5)	Average Peaking Unit Equivalent $/MWh (6)	PUE FAC Disallowance $ (7)
August	501,747	744	674.4	512,306	60,527	$ 3,145,704	$ 51.97	$ 77.43	$ 322,570

Generating Unit	Dispatched Generation MWh (8)	KPCO Capability MW (9)	Max Generation for Month MWh	Capacity Factor	Average Cost per MWh (10)	Forced Outages MWh (11)	Fuel Costs Assigned During Forced Outages $ (12)	Purchase Costs Substituted During Forced Outages $ (13)	Forced Outage Replacement Costs Removed From FAC $ (14)
Big Sandy 1	37,857	295	219,480	17%	$ 54.89				
Mitchell 1	129,478	385	286,440	45%	$ 24.78	27,425	$ 677,145	$ 1,579,370	$ 902,224
Mitchell 2	226,638	395	293,880	77%	$ 20.84				
Rockport 1	39,365	198	147,312	27%	$ 33.01				
Rockport 2	78,968	195	145,080	54%	$ 31.67				
Total	512,306	1,468	1,092,192	47%		27,425	$ 677,145	$ 1,579,370	$ 902,224

(1) Company's Response to Staff 1-16 Attachment 4, 08-2021 Worksheet Tab, Cell N756
(2) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3 and 05-2021 Worksheet Tab, Cell L756
(3) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cell F750
(4) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cell G750
(5) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cell G754
(6) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Average of Cell Column L
(7) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cell T750, Matches FAC Final Fuel Cost Schedule for August 2021 Actual Results Filed with September 2021 Estimated Fuel Costs page 5 of 5
(8) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3
(9) Company's Response to Staff 1-16 Attachment 4, 08-21 KPCo Gen Data Worksheet Tab
(10) Company's Response to Staff 1-16 Attachment 4, 08-21 Hourly Purch Alloc Worksheet Tab, Cell Columns M through Q
(11) Company's Response to Staff 1-16 Attachment 4, 08-2021 Worksheet Tab, Cell R757, Matches FAC Final Fuel Cost Schedule
(12) Company's Response to Staff 1-16 Attachment 4, 08-2021 Worksheet Tab, Cell AA757, Matches FAC Final Fuel Cost Schedule
(13) Company's Response to Staff 1-16 Attachment 4, 08-2021 Worksheet Tab, Cell V757, Matches FAC Final Fuel Cost Schedule
(14) Company's Response to Staff 1-16 Attachment 4, 08-2021 Worksheet Tab, Cell AB757, Matches FAC Final Fuel Cost Schedule

3

Kentucky Power Company
July 2021 Selected Data

Month	Sum of Native Load MWh for All Hours in Month (1)	Hours in Month	Average Hourly Native Load MW	Total Dispatched Generation MWh for All Hours in Month (2)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load MWh (3)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load $ (4)	Average Cost of Market Purchases (Non-Rockport) Assigned to Native Load $/MWh (5)	Average Peaking Unit Equivalent $/MWh (6)	PUE FAC Disallowance $ (7)
July	493,608	744	663.5	583,941	24,761	$ 755,860	$ 30.53	$ 72.14	$ 1,355

Generating Unit	Dispatched Generation MWh (8)	KPCO Capability MW (9)	Max Generation for Month MWh	Capacity Factor	Average Cost per MWh (10)	Forced Outages MWh (11)	Fuel Costs Assigned During Forced Outages $ (12)	Purchase Costs Substituted During Forced Outages $ (13)	Forced Outage Replacement Costs Removed From FAC $ (14)
Big Sandy 1	98,070	295	219,480	45%	$ 38.99				
Mitchell 1	155,078	385	286,440	54%	$ 23.73				
Mitchell 2	209,026	395	293,880	71%	$ 21.55				
Rockport 1	55,541	198	147,312	38%	$ 33.44				
Rockport 2	66,227	195	145,080	46%	$ 33.46				
Total	583,941	1,468	1,092,192	53%		-	$ -	$ -	$ -

(1) Company's Response to Staff 1-16 Attachment 3, 07-2021 Worksheet Tab, Cell N756
(2) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3 and 07-2021 Worksheet Tab, Cell L756
(3) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cell F750
(4) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cell G750
(5) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cell G754
(6) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Average of Cell Column L
(7) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cell T750, Matches FAC Final Fuel Cost Schedule for July 2021 Actual Results Filed with August 2021 Estimated Fuel Costs page 5 of 5
(8) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3
(9) Company's Response to Staff 1-16 Attachment 3, 07-21 KPCo Gen Data Worksheet Tab
(10) Company's Response to Staff 1-16 Attachment 3, 07-21 Hourly Purch Alloc Worksheet Tab, Cell Columns M through Q
(11) Company's Response to Staff 1-16 Attachment 3, 07-2021 Worksheet Tab, Cell R757, Matches FAC Final Fuel Cost Schedule
(12) Company's Response to Staff 1-16 Attachment 3, 07-2021 Worksheet Tab, Cell AA757, Matches FAC Final Fuel Cost Schedule
(13) Company's Response to Staff 1-16 Attachment 3, 07-2021 Worksheet Tab, Cell V757, Matches FAC Final Fuel Cost Schedule
(14) Company's Response to Staff 1-16 Attachment 3, 07-2021 Worksheet Tab, Cell AB757, Matches FAC Final Fuel Cost Schedule

4

Kentucky Power Company
June 2021 Selected Data

Month	Sum of Native Load MWh for All Hours in Month (1)	Hours in Month	Average Hourly Native Load MW	Total Dispatched Generation MWh for All Hours in Month (2)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load MWh (3)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load $ (4)	Average Cost of Market Purchases (Non-Rockport) Assigned to Native Load $/MWh (5)	Average Peaking Unit Equivalent $/MWh (6)	PUE FAC Disallowance $ (7)
June	450,000	720	625.0	494,026	68,519	$ 1,978,453	$ 28.87	$ 67.09	$ -

Generating Unit	Dispatched Generation MWh (8)	KPCO Capability MW (9)	Max Generation for Month MWh	Capacity Factor	Average Cost per MWh (10)	Forced Outages MWh (11)	Fuel Costs Assigned During Forced Outages $ (12)	Purchase Costs Substituted During Forced Outages $ (13)	Forced Outage Replacement Costs Removed From FAC $ (14)
Big Sandy 1	63,219	295	212,400	30%	$ 36.47	3,639	$ 115,278	$ 209,441	$ 94,162
Mitchell 1	154,970	385	277,200	56%	$ 22.97	1,558	$ 49,349	$ 89,658	$ 40,309
Mitchell 2	145,143	395	284,400	51%	$ 22.20				
Rockport 1	89,702	198	142,560	63%	$ 28.60				
Rockport 2	40,992	195	140,400	29%	$ 30.94				
Total	494,026	1,468	1,056,960	47%		5,197	$ 164,627	$ 299,098	$ 134,471

(1) Company's Response to Staff 1-16 Attachment 2, 06-2021 Worksheet Tab, Cell N732
(2) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3 and 06-2021 Worksheet Tab, Cell L732
(3) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cell F726
(4) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cell G726
(5) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cell G730
(6) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Average of Cell Column L
(7) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cell T726, Matches FAC Final Fuel Cost Schedule for June 2021 Actual Results Filed with July 2021 Estimated Fuel Costs page 5 of 5
(8) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3
(9) Company's Response to Staff 1-16 Attachment 2, 06-21 KPCo Gen Data Worksheet Tab
(10) Company's Response to Staff 1-16 Attachment 2, 06-21 Hourly Purch Alloc Worksheet Tab, Cell Columns M through Q
(11) Company's Response to Staff 1-16 Attachment 2, 06-2021 Worksheet Tab, Cell R733 and T733, Matches FAC Final Fuel Cost Schedule
(12) Company's Response to Staff 1-16 Attachment 2, 06-2021 Worksheet Tab, Cell AA733, Matches FAC Final Fuel Cost Schedule
(13) Company's Response to Staff 1-16 Attachment 2, 06-2021 Worksheet Tab, Cell V733, Matches FAC Final Fuel Cost Schedule
(14) Company's Response to Staff 1-16 Attachment 2, 06-2021 Worksheet Tab, Cell AB733, Matches FAC Final Fuel Cost Schedule

Kentucky Power Company
May 2021 Selected Data

Month	Sum of Native Load MWh for All Hours in Month (1)	Hours in Month	Average Hourly Native Load MW	Total Dispatched Generation MWh for All Hours in Month (2)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load MWh (3)	Sum of Market Purchases (Non-Rockport) Assigned to Native Load $ (4)	Average Cost of Market Purchases (Non-Rockport) Assigned to Native Load $/MWh (5)	Average Peaking Unit Equivalent $/MWh (6)	PUE FAC Disallowance $ (7)
May	409,222	744	550.0	299,498	118,767	$ 2,920,374	$ 24.59	$ 63.37	$ 27,541

Generating Unit	Dispatched Generation MWh (8)	KPCO Capability MW (9)	Max Generation for Month MWh	Capacity Factor	Average Cost per MWh (10)	Forced Outages MWh (11)	Fuel Costs Assigned During Forced Outages $ (12)	Purchase Costs Substituted During Forced Outages $ (13)	Forced Outage Replacement Costs Removed From FAC $ (14)
Big Sandy 1	38,078	295	219,480	17%	$ 39.47				
Mitchell 1	0	385	286,440	0%	$ -	8,913	$ 180,880	$ 198,904	$ 18,024
Mitchell 2	191,146	395	293,880	65%	$ 21.21				
Rockport 1	70,274	198	147,312	48%	$ 29.30				
Rockport 2	0	195	145,080	0%	$ -				
Total	299,498	1,468	1,092,192	27%		8,913	$ 180,880	$ 198,904	$ 18,024

(1) Company's Response to Staff 1-16 Attachment 1, 05-2021 Worksheet Tab, Cell N758
(2) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3 and 05-2021 Worksheet Tab, Cell L758
(3) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cell F750
(4) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cell G750
(5) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cell G754
(6) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Average of Cell Column L
(7) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cell T750, Matches FAC Final Fuel Cost Schedule for May 2021 Actual Results Filed with June 2021 Estimated Fuel Costs page 5 of 5
(8) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cells M3 through Q3
(9) Company's Response to Staff 1-16 Attachment 1, 05-21 KPCo Gen Data Worksheet Tab
(10) Company's Response to Staff 1-16 Attachment 1, 05-21 Hourly Purch Alloc Worksheet Tab, Cell Columns M through Q
(11) Company's Response to Staff 1-16 Attachment 1, 05-2021 Worksheet Tab, Cell R759, Matches FAC Final Fuel Cost Schedule
(12) Company's Response to Staff 1-16 Attachment 1, 05-2021 Worksheet Tab, Cell AA759, Matches FAC Final Fuel Cost Schedule
(13) Company's Response to Staff 1-16 Attachment 1, 05-2021 Worksheet Tab, Cell V759, Matches FAC Final Fuel Cost Schedule
(14) Company's Response to Staff 1-16 Attachment 1, 05-2021 Worksheet Tab, Cell AB759, Matches FAC Final Fuel Cost Schedule

6

#11

Ceredo Unit 1 2021 Operations Chart

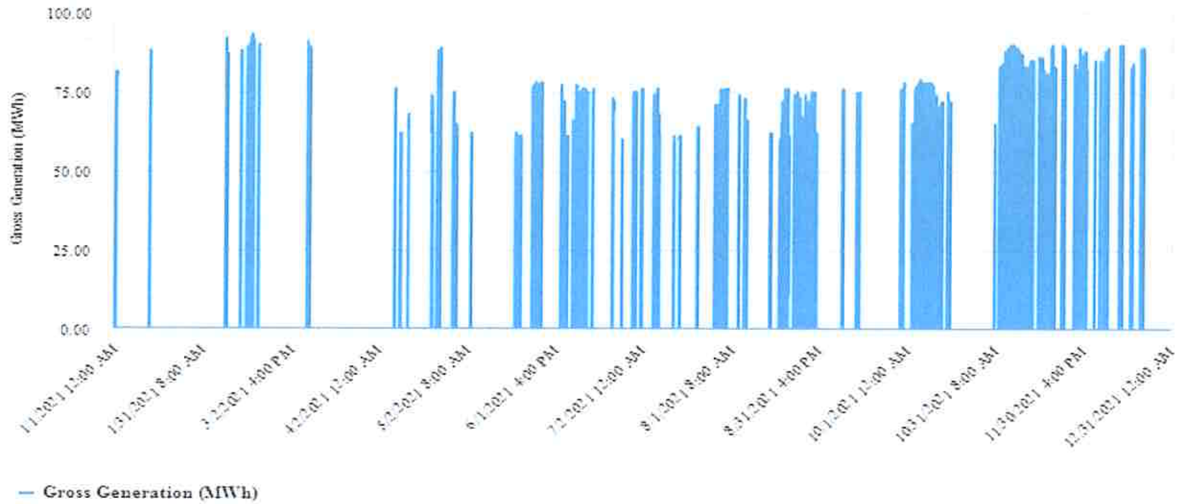
Including Sharefile Link To Underlying Data

S&P Capital IQ PRO

Ceredo | Unit Hourly Operations (Chart)

Periods From: 01/01/2021 To: 12/31/2021

Ceredo CT 01 - Gross Generation (MWh)



every hour of the year -
every zero is an hour
1-May-17

for ecal
This data is from EPA's Continuous Emissions Monitoring System (CEMS).
Hourly data is reported as hour beginning.

for each period how many times did the power plant operating and how long was the average run time .

#11 Sharefile Link
To Underlying Data

https://bkllawfirm.sharefile.com/d-s02bfa91fcb954837b88f699d1f58a415

#12

EIA Annual Energy Outlook 2022, C*ost and Performance Characteristics of New Generating Technologies* (March 2022)

Independent Statistics & Analysis
U.S. Energy Information Administration

March 2022

Cost and Performance Characteristics of New Generating Technologies, *Annual Energy Outlook 2022*

The tables presented below are also published in the Electricity Market Module chapter of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2022* (AEO2022) Assumptions document. Table 1 represents our assessment of the cost to develop and install various generating technologies used in the electric power sector. Generating technologies typically found in end-use applications, such as combined heat and power or roof-top solar photovoltaics (PV), will be described elsewhere in the Assumptions document. The costs shown in Table 1, except as noted below, are the costs for a typical facility for each generating technology before adjusting for regional cost factors. Overnight costs exclude interest accrued during plant construction and development. Technologies with limited commercial experience may include a technological optimism factor to account for the tendency to underestimate the full engineering and development costs for new technologies during technology research and development.

All technologies demonstrate some degree of variability in cost, based on project size, location, and access to key infrastructure (such as grid interconnections, fuel supply, and transportation). For wind and solar PV, in particular, the cost favorability of the lowest-cost regions compound the underlying variability in regional cost and create a significant differential between the unadjusted costs and the capacity-weighted average national costs as observed from recent market experience. To reflect this difference, we report a weighted average cost for both wind and solar PV, based on the regional cost factors assumed for these technologies in AEO2022 and the actual regional distribution of the builds that occurred in 2020 (Table 1).

Table 2 shows a full listing of the overnight costs for each technology and electricity region, if the resource or technology is available to be built in the given region. The regional costs reflect the impact of locality adjustments, including one to address ambient air conditions for technologies that include a combustion turbine and one to adjust for additional costs associated with accessing remote wind resources. Temperature, humidity, and air pressure can affect the available capacity of a combustion turbine, and our modeling addresses these possible effects through an additional cost multiplier by region. Unlike most other generation technologies where fuel can be transported to the plant, wind generators must be located in areas with the best wind resources. Sites that are located near existing transmission with access to a road network or are located on lower development-cost lands are generally built up first, after which additional costs may be incurred to access sites with less favorable characteristics. We represent this trend through a multiplier applied to the wind plant capital costs that increases as the best sites in a region are developed.

Table 1. Cost and performance characteristics of new central station electricity generating technologies

Technology	First available year[a]	Size (MW)	Lead time (years)	Base overnight cost[b] (2021$/kW)	Techno-logical optimism factor[c]	Total overnight cost[d,e] (2021$/kW)	Variable O&M[f] (2021 $/MWh)	Fixed O&M (2021$/ kW-y)	Heat rate[g] (Btu/kWh)
Ultra-supercritical coal (USC)	2025	650	4	$4,074	1.00	$4,074	$4.71	$42.49	8,638
USC with 30% carbon capture and sequestration (CCS)	2025	650	4	$5,045	1.01	$5,096	$7.41	$56.84	9,751
USC with 90% CCS	2025	650	4	$6,495	1.02	$6,625	$11.49	$62.34	12,507
Combined-cycle—single-shaft	2024	418	3	$1,201	1.00	$1,201	$2.67	$14.76	6,431
Combined-cycle—multi-shaft	2024	1,083	3	$1,062	1.00	$1,062	$1.96	$12.77	6,370
Combined-cycle with 90% CCS	2024	377	3	$2,736	1.04	$2,845	$6.11	$28.89	7,124
Internal combustion engine	2023	21	2	$2,018	1.00	$2,018	$5.96	$36.81	8,295
Combustion turbine—aeroderivative[h]	2023	105	2	$1,294	1.00	$1,294	$4.92	$17.06	9,124
Combustion turbine—industrial frame	2023	237	2	$785	1.00	$785	$4.71	$7.33	9,905
Fuel cells	2024	10	3	$6,639	1.09	$7,224	$0.62	$32.23	6,469
Nuclear—light water reactor	2027	2,156	6	$6,695	1.05	$7,030	$2.48	$127.35	10,443
Nuclear—small modular reactor	2028	600	6	$6,861	1.10	$7,547	$3.14	$99.46	10,443
Distributed generation—base	2024	2	3	$1,731	1.00	$1,731	$9.01	$20.27	8,923
Distributed generation—peak	2023	1	2	$2,079	1.00	$2,079	$9.01	$20.27	9,907
Battery storage	2022	50	1	$1,316	1.00	$1,316	$0.00	$25.96	NA
Biomass	2025	50	4	$4,524	1.00	$4,525	$5.06	$131.62	13,500
Geothermal[i, j]	2025	50	4	$3,076	1.00	$3,076	$1.21	$143.22	8,813
Conventional hydropower[j]	2025	100	4	$3,083	1.00	$3,083	$1.46	$43.78	NA
Wind[e]	2024	200	3	$1,718	1.00	$1,718	$0.00	$27.57	NA
Wind offshore[i]	2025	400	4	$4,833	1.25	$6,041	$0.00	$115.16	NA
Solar thermal[i]	2024	115	3	$7,895	1.00	$7,895	$0.00	$89.39	NA
Solar photovoltaic (PV) with tracking[e, i, k]	2023	150	2	$1,327	1.00	$1,327	$0.00	$15.97	NA
Solar PV with storage[i, k]	2023	150	2	$1,748	1.00	$1,748	$0.00	$33.67	NA

Source: We primarily base input costs on a report provided by external consultants: Sargent & Lundy, December 2019. We most recently updated hydropower site costs for non-powered dams for AEO2018 using data from Oak Ridge National Lab

Note: MW=megawatt, kW=kilowatt, MWh=megawatthour, kW-y=kilowatt-year, kWh=kilowatthour; Btu=British thermal unit

[a] The first year that a new unit could become operational.

[b] Base cost includes project contingency costs.

[c] We apply the technological optimism factor to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.

[d] Overnight capital cost includes contingency factors and excludes regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. The capital costs represent current costs for plants that would come online in 2022.

[e] Total overnight cost for wind and solar PV technologies in the table are the average input value across all 25 electricity market regions, as weighted by the respective capacity of that type installed during 2020 in each region to account for the substantial regional variation in wind and solar costs (Table 4). The input value used for onshore wind in AEO2022 was $1,411 per kilowatt (kW), and for solar PV with tracking, it was $1,323/kW, which represents the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs throughout the country.

[f] O&M = Operations and maintenance.

[g] The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, *Annual Electric Generator Report*. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load. For hydropower, wind, solar, and geothermal technologies, no heat rate is reported because the power is generated without fuel combustion, and no set British thermal unit conversion factors exist. The module calculates the average heat rate for fossil-fuel generation in each year to report primary energy consumption displaced for these resources.

[h] Combustion turbine aeroderivative units can be built by the module before 2023, if necessary, to meet a region's reserve margin.

[i] Capital costs are shown before investment tax credits are applied.

[j] Because geothermal and hydropower cost and performance characteristics are specific for each site, the table entries show the cost of the least expensive plant that could be built in the Northwest region for hydro and the Great Basin region for geothermal, where most of the proposed sites are located.

[k] Costs and capacities are expressed in terms of net AC (alternating current) power available to the grid for the installed capacity.

Table 2. Total overnight capital costs of new electricity generating technologies by region

2021 dollars per kilowatt

Technology	1 TRE	2 FRCC	3 MISW	4 MISC	5 MISE	6 MISS	7 ISNE	8 NYCW	9 NYUP	10 PJME	11 PJMW	12 PJMC	13 PJMD
Ultra-supercritical coal (USC)	$3,786	$3,897	$4,259	$4,371	$4,422	$3,918	$4,721	NA	$4,614	$4,763	$4,064	$5,120	$4,385
USC with 30% CCS	$4,777	$4,903	$5,294	$5,437	$5,480	$4,935	$5,846	NA	$5,729	$5,883	$5,094	$6,254	$5,477
USC with 90% CCS	$6,252	$6,411	$6,841	$7,072	$7,078	$6,473	$7,495	NA	$7,303	$7,508	$6,601	$7,994	$7,015
CC—single-shaft	$1,085	$1,107	$1,235	$1,246	$1,277	$1,117	$1,441	$1,912	$1,445	$1,443	$1,197	$1,446	$1,377
CC—multi-shaft	$944	$968	$1,098	$1,117	$1,146	$979	$1,259	$1,725	$1,238	$1,266	$1,037	$1,327	$1,170
CC with 90% CCS	$2,668	$2,693	$2,877	$2,884	$2,928	$2,718	$3,021	$3,422	$2,953	$2,996	$2,756	$3,124	$2,871
Internal combustion engine	$1,898	$1,940	$2,073	$2,155	$2,131	$1,966	$2,209	$2,769	$2,125	$2,209	$1,980	$2,408	$2,056
CT—aeroderivative	$1,145	$1,168	$1,354	$1,357	$1,398	$1,193	$1,456	$1,864	$1,405	$1,448	$1,242	$1,591	$1,317
CT—industrial frame	$692	$707	$822	$826	$851	$723	$886	$1,144	$854	$882	$753	$971	$800
Fuel cells	$6,933	$7,041	$7,362	$7,680	$7,534	$7,159	$7,815	$9,201	$7,498	$7,748	$7,138	$8,261	$7,358
Nuclear—light water reactor	$6,636	$6,779	$7,157	$7,807	$7,530	$7,000	$7,964	NA	$7,430	$7,781	$6,878	$8,556	$7,158
Nuclear—small modular reactor	$7,032	$7,197	$7,841	$8,176	$8,173	$7,287	$8,441	NA	$8,040	$8,459	$7,376	$9,438	$7,660
Distributed generation—base	$1,563	$1,595	$1,779	$1,795	$1,840	$1,609	$2,076	$2,754	$2,081	$2,079	$1,724	$2,083	$1,984
Distributed generation—peak	$1,839	$1,877	$2,174	$2,180	$2,246	$1,916	$2,339	$2,994	$2,257	$2,326	$1,995	$2,555	$2,116
Battery storage	$1,316	$1,320	$1,301	$1,364	$1,319	$1,347	$1,357	$1,351	$1,321	$1,325	$1,313	$1,329	$1,325
Biomass	$4,198	$4,313	$4,669	$4,824	$4,835	$4,348	$5,372	$7,292	$5,389	$5,483	$4,611	$5,493	$5,255
Geothermal	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Conventional hydropower	$4,498	$5,495	$2,186	$1,453	$2,959	$4,378	$2,025	NA	$4,144	$4,305	$3,752	NA	$3,808
Wind	$2,757	NA	$1,552	$1,411	$1,690	$1,411	$1,870	NA	$2,281	$1,870	$1,411	$2,055	$1,948
Wind offshore	$5,901	$7,080	$6,984	NA	$7,234	NA	$7,047	$6,079	$7,370	$6,755	$5,524	$7,999	$6,293
Solar thermal	$7,616	$7,731	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Solar PV with tracking	$1,304	$1,279	$1,323	$1,372	$1,357	$1,290	$1,370	$1,612	$1,357	$1,397	$1,320	$1,440	$1,317
Solar PV with storage	$1,692	$1,710	$1,761	$1,817	$1,792	$1,727	$1,828	$2,078	$1,796	$1,832	$1,721	$1,905	$1,781

Technology	14 SRCA	15 SRSE	16 SRCE	17 SPPS	18 SPPC	19 SPPN	20 SRSG	21 CANO	22 CASO	23 NWPP	24 RMRG	25 BASN
Ultra-supercritical coal (USC)	$3,920	$3,979	$4,032	$3,947	$4,193	$3,991	$4,159	NA	NA	$4,406	$4,119	$4,297
USC with 30% CCS	$4,939	$4,985	$5,059	$4,952	$5,226	$4,999	$5,215	NA	NA	$5,480	$5,159	$5,353
USC with 90% CCS	$6,485	$6,542	$6,620	$6,451	$6,778	$6,497	$6,758	NA	NA	$7,090	$6,658	$6,967
CC—single-shaft	$1,103	$1,116	$1,150	$1,115	$1,183	$1,104	$1,085	$1,590	$1,553	$1,264	$1,023	$1,106
CC—multi-shaft	$968	$980	$1,016	$979	$1,051	$971	$934	$1,398	$1,359	$1,096	$880	$987
CC with 90% CCS	$2,684	$2,698	$2,759	$2,688	$2,777	$2,647	$2,448	$3,071	$3,036	$2,833	$2,303	$2,586
Internal combustion engine	$1,977	$1,982	$2,017	$1,962	$2,068	$1,982	$2,001	$2,398	$2,355	$2,133	$1,975	$2,114
CT—aeroderivative	$1,186	$1,196	$1,241	$1,194	$1,279	$1,203	$1,086	$1,529	$1,491	$1,341	$1,051	$1,198
CT— industrial frame	$718	$726	$753	$724	$777	$729	$658	$934	$910	$816	$637	$728
Fuel cells	$7,211	$7,205	$7,304	$7,080	$7,376	$7,143	$7,243	$8,299	$8,203	$7,585	$7,104	$7,567
Nuclear—light water reactor	$7,090	$7,035	$7,263	$6,807	$7,198	$6,805	$7,058	NA	NA	$7,640	$6,837	$7,648
Nuclear—small modular reactor	$7,323	$7,380	$7,547	$7,306	$7,759	$7,368	$7,465	NA	NA	$8,083	$7,386	$8,028
Distributed generation—base	$1,589	$1,608	$1,657	$1,606	$1,705	$1,591	$1,563	$2,290	$2,238	$1,821	$1,474	$1,593
Distributed generation—peak	$1,905	$1,922	$1,994	$1,919	$2,055	$1,932	$1,744	$2,456	$2,394	$2,154	$1,688	$1,924
Battery storage	$1,359	$1,340	$1,357	$1,310	$1,318	$1,302	$1,333	$1,371	$1,373	$1,348	$1,305	$1,357
Biomass	$4,364	$4,397	$4,455	$4,368	$4,641	$4,460	$4,777	$6,119	$5,981	$4,939	$4,732	$4,731
Geothermal	NA	NA	NA	NA	NA	NA	$3,135	$3,109	$2,517	$3,043	NA	$3,076
Conventional hydropower	$2,120	$4,599	$2,377	$4,550	$1,917	$1,802	$3,655	$3,867	$3,723	$3,083	$3,681	$4,023
Wind	$1,683	$1,907	$1,411	$1,411	$1,552	$1,552	$1,411	$3,116	$2,447	$2,057	$1,411	$1,411
Wind offshore	$5,437	NA	NA	NA	NA	NA	NA	$9,112	$9,560	$6,836	NA	NA
Solar thermal	NA	NA	NA	$7,693	$7,991	$7,614	$7,980	$9,400	$9,282	$8,493	$7,668	$8,510
Solar PV with tracking	$1,343	$1,276	$1,318	$1,278	$1,328	$1,287	$1,300	$1,447	$1,440	$1,332	$1,315	$1,327
Solar PV with storage	$1,739	$1,721	$1,742	$1,709	$1,765	$1,727	$1,736	$1,903	$1,898	$1,795	$1,729	$1,791

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis

Notes: Costs include contingency factors, regional cost multipliers, and ambient condition multipliers. Interest charges are excluded. The costs are shown before investment tax credits are applied.

NA = not available; plant type cannot be built in the region because of a lack of resources, sites, or specific state legislation.

USC = ultra-supercritical, CCS = carbon capture and sequestration, CC = combined cycle, CT = combustion turbine, PV = photovoltaic

Electricity Market Module region map

#13

Capacity Factor Data

KPSC Case No. 2022-00036
Commission Staff's First set of Data Requests
Dated March 31, 2022
Item No. 17
Page 1 of 1

Kentucky Power Company
Fuel Adjustment Case No. 2022-00036
Generating Unit Net Capacity Factor [%]
May 1, 2021-October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
Big Sandy 1	17.33	29.72	44.62	17.23	30.74	0.00
Mitchell 1	0.00	55.90	54.13	45.20	47.19	9.64
Mitchell 2	65.03	51.02	71.11	77.10	55.23	45.54

Kentucky Power Company Fuel Adjustment Case No. 2022-00036 Generating Unit Net Capacity Factor [%] May 1, 2021-October 31, 2021						
	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21
Rockport 1	47.70	62.92	37.70	26.72	0.00	0.00
Rockport 2	0.00	29.20	45.65	54.43	8.56	0.00

2021 CAPACITY FACTORS BY UNIT (%)

Rockport 1	23.17
Rockport 2	19.00
Mitchell 1	26.39
Mitchell 2	43.19
Big Sandy1	24.17
Ghent 1	64.45
Ghent 2	58.45
Ghent 3	66.08
Ghent 4	59.83
Trimble County 1	65.33
Trimble County 2	79.81
Mill Creek 1	50.45
Mill Creek 2	42.69
Mill Creek 3	61.83
Mill Creek 4	66.55
D.B. Wilson 1	83.59
HL Spurlock 1	74.96
HL Spurlock 2	58.77
HL Spurlock 3	80.08
HL Spurlock 4	83.20
East Bend 2	48.38

S&P Capital IQ PRO

Rockport | Unit Monthly Operations

Unit : Rockport ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0
Net Generation (MWh)	2,638,457	15,284	601,109	121,072	201,778	468,494	598,010	370,274	262,436	0	0	0	0
Gross Generation (MWh)	2,856,825	18,333	650,120	130,331	221,959	510,874	638,251	403,667	283,290				
Capacity Factor (%)	23.17	1.58	68.81	12.52	21.56	48.44	63.89	38.28	27.13	0.00	0.00	0.00	0.00
Heat Rate (Btu/kWh)	10,586	24,203	10,139	10,167	10,775	10,877	10,170	10,899	10,849				
Heat Input (MMBtu)	29,450,462	268,303	6,402,697	1,340,382	2,334,142	5,367,198	6,590,250	4,244,346	2,903,143				
Operating Time (hours)	3,833	105	672	144	348	744	720	675	426				
CO2 Emissions (tons)	3,088,767	28,140	671,514	140,579	244,805	562,912	691,186	445,148	304,482				
CO2 Emissions Rate (lb/MMBtu)	209.7601	209.7626	209.7598	209.7599	209.7603	209.7600	209.7602	209.7606	209.7602				
NOX Emissions (lbs)	2,071,835	23,717	426,947	108,437	165,786	367,797	479,953	277,563	221,635				
NOX Emissions Rate (lb/MMBtu)	0.0703	0.0884	0.0667	0.0809	0.0710	0.0685	0.0728	0.0654	0.0763				
SO2 Emissions (lbs)	3,024,605	36,794	692,197	169,588	209,711	464,037	680,570	396,519	375,190				
SO2 Emissions Rate (lb/MMBtu)	0.1027	0.1371	0.1081	0.1265	0.0898	0.0865	0.1033	0.0934	0.1292				

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Rockport | Unit Monthly Operations

Unit : Rockport ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0	1,300.0
Net Generation (MWh)	2,163,706	0	346,115	36,227	0	0	273,282	441,511	526,453	80,167	0	0	459,951
Gross Generation (MWh)	2,322,312		370,729	39,330			291,494	474,828	564,117	86,012		2	495,800
Capacity Factor (%)	19.00	0.00	39.62	3.75	0.00	0.00	29.20	45.65	54.43	8.56	0.00	0.00	47.55
Heat Rate (Btu/kWh)	10,814		10,494	10,797			10,546	10,892	10,841	11,572			10,961
Heat Input (MMBtu)	23,966,418		3,598,312	388,856			2,867,597	5,006,003	5,881,885	960,586		942	5,262,236
Operating Time (hours)	3,269		448	76			350	744	744	161		2	743
CO2 Emissions (tons)	2,512,317		377,391	40,784			300,754	525,029	616,893	99,464		99	551,904
CO2 Emissions Rate (lb/MMBtu)	209.6531		209.7602	209.7613			209.7600	209.7597	209.7604	207.0898		209.7442	209.7601
NOX Emissions (lbs)	1,650,706		242,751	30,523			208,424	338,367	452,033	55,118		18	323,473
NOX Emissions Rate (lb/MMBtu)	0.0689		0.0675	0.0785			0.0727	0.0676	0.0769	0.0574		0.0187	0.0615
SO2 Emissions (lbs)	2,599,416		398,801	52,207			353,886	483,599	731,625	50,683		0	528,615
SO2 Emissions Rate (lb/MMBtu)	0.1085		0.1108	0.1343			0.1234	0.0966	0.1244	0.0528		0.0000	0.1005

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Mitchell (WV) | Unit Monthly Operations

Unit : Mitchell (WV) ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	770.0	770.0	770.0	770.0	770.0	770.0	770.0	770.0	770.0	770.0	770.0	770.0	770.0
Net Generation (MWh)	1,780,164	237,093	189,035	73,955	84,174	0	309,940	310,156	258,956	261,629	55,226	0	0
Gross Generation (MWh)	1,936,499	254,703	202,435	80,772	90,686		340,184	340,198	282,667	284,535	60,319		
Capacity Factor (%)	26.39	41.39	36.53	12.91	15.18	0.00	55.91	54.14	45.20	47.19	9.64	0.00	0.00
Heat Rate (Btu/kWh)	10,838	10,873	11,142	11,691	10,629		10,660	11,112	10,766	10,292	11,026		
Heat Input (MMBtu)	19,106,486	2,419,347	2,001,443	856,799	922,575	1,174	3,415,223	3,361,233	2,769,797	2,762,847	596,048		
Operating Time (hours)	3,531	483	378	239	212	2	598	569	450	489	114		
CO2 Emissions (tons)	1,957,286	248,225	205,349	87,908	94,656		350,384	344,842	283,579	281,189	61,154		
CO2 Emissions Rate (lb/MMBtu)	204.8819	205.1998	205.2009	205.2007	205.1996		205.1894	205.1880	204.7655	203.5502	205.1986		
NOX Emissions (lbs)	1,531,784	189,876	179,376	76,129	68,786	122	253,558	259,660	218,782	230,595	54,899		
NOX Emissions Rate (lb/MMBtu)	0.0802	0.0785	0.0896	0.0889	0.0746	0.1040	0.0742	0.0773	0.0790	0.0835	0.0921		
SO2 Emissions (lbs)	1,488,700	224,625	118,397	96,743	61,094		261,923	280,814	192,810	223,039	29,255		
SO2 Emissions Rate (lb/MMBtu)	0.0779	0.0928	0.0592	0.1129	0.0662		0.0767	0.0835	0.0696	0.0807	0.0491		

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

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S&P Capital IQ PRO

Mitchell (WV) | Unit Monthly Operations

Unit : Mitchell (WV) ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	790.0	790.0	790.0	790.0	790.0	790.0	790.0	790.0	790.0	790.0	790.0	790.0	790.0
Net Generation (MWh)	2,988,940	0	205,693	53,418	61,014	382,291	290,286	418,052	453,276	314,253	267,755	170,514	372,388
Gross Generation (MWh)	3,221,725		218,470	57,190	66,824	416,165	313,221	450,049	486,672	337,204	287,224	185,764	402,942
Capacity Factor (%)	43.19	0.00	38.75	9.09	10.73	65.04	51.03	71.13	77.12	55.25	45.56	29.98	63.36
Heat Rate (Btu/kWh)	10,309		10,849	10,769	10,286	10,437	10,350	9,949	10,062	9,987	10,080	10,783	10,682
Heat Input (MMBtu)	30,590,000		2,053,726	536,918	624,709	3,942,701	2,991,093	4,304,583	4,455,913	3,181,654	2,751,539	1,851,429	3,895,736
Operating Time (hours)	5,388		377	125	134	744	504	681	744	517	480	394	690
CO2 Emissions (tons)	3,138,535		210,713	55,088	64,095	404,520	306,887	441,649	457,177	326,438	282,308	189,957	399,703
CO2 Emissions Rate (lb/MMBtu)	205.2000		205.2011	205.1988	205.1996	205.1994	205.2002	205.1996	205.2003	205.2000	205.2002	205.2001	205.2003
NOX Emissions (lbs)	2,297,044		178,296	44,060	66,144	236,535	165,422	282,182	320,476	251,891	229,416	165,435	357,187
NOX Emissions Rate (lb/MMBtu)	0.0751		0.0868	0.0821	0.1059	0.0600	0.0553	0.0656	0.0719	0.0792	0.0834	0.0894	0.0917
SO2 Emissions (lbs)	2,359,838		100,108	20,532	61,379	347,585	236,369	316,150	333,497	249,738	287,956	147,658	258,865
SO2 Emissions Rate (lb/MMBtu)	0.0771		0.0487	0.0382	0.0983	0.0882	0.0790	0.0734	0.0748	0.0785	0.1047	0.0798	0.0664

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Big Sandy | Plant Financials

Periods : Last Five Years

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operational Statistics					
Operating Capacity (MW)	260.00	260.00	260.00	260.00	260.00
Summer Peak Capacity (MW)	260.00	260.00	260.00	260.00	260.00
Winter Peak Capacity (MW)	260.00	260.00	260.00	260.00	260.00
Net Generation (MWh)	563,707	624,804	1,062,894	912,638	550,601
Capacity Factor (%)	24.75	27.43	46.67	39.96	24.17
Heat Rate	10,266	10,056	9,976	9,908	10,116

Reported Plant Production Costs

Fuel Expenses

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Fuel Expense ($000)	26,202	22,576	34,166	21,301	25,661
Fuel Expense ($/MWh)	46.48	36.13	32.14	23.34	46.61
Estimated Fuel Cost?	No	No	No	No	No

Non-Fuel Operating & Maintenance Expenses

	2017 Y	2018 Y	2019 Y	2020 Y	2021 Y
Operating Supervision and Engineering ($)	685,766	666,884	688,937	1,951,886	2,454,899
Steam Expense ($)	9,555	24,606	18,596	13,171	980
Steam Transferred (Credit) ($)	0	0	0	0	0
Electric Expense ($)	2,190	1,102	5,794	7,092	1,011
Miscellaneous Power Expenses ($)	3,672,070	3,603,051	4,403,950	2,264,865	1,601,775
Rental Expense ($)	0	0	0	0	0
Allowance Expense ($)	40,248	27,047	46,498	18,164	4,563
Non-fuel Operating Expense ($)	4,409,829	4,322,690	5,163,775	4,255,178	4,063,228
Maintenance Supervision Expense ($)	323,068	317,944	337,349	371,965	341,137
Maintenance of Structures ($)	866,070	668,180	935,620	1,046,307	764,631
Maintenance of Boiler Plant ($)	1,535,270	3,088,296	1,146,617	2,073,487	2,526,988
Maintenance of Electric Plant ($)	1,086,902	1,350,025	789,518	1,083,391	1,215,477
Maintenance of Other Plant ($)	885,833	869,077	760,373	521,476	616,314
Total Maintenance Expense ($)	4,697,143	6,293,522	3,969,477	5,096,626	5,464,547

S&P Capital IQ PRO

Ghent | Unit Monthly Operations

Unit : Ghent ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	476.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0	476.0
Net Generation (MWh)	2,687,571	292,876	290,246	48,922	(488)	126,701	294,321	321,752	295,722	283,631	296,045	279,541	158,302
Gross Generation (MWh)	2,929,929	316,716	314,680	54,536		140,778	319,050	349,945	323,102	309,107	322,652	305,145	174,218
Capacity Factor (%)	64.45	82.70	90.74	13.81	(0.14)	35.78	85.88	90.85	83.50	82.76	83.59	81.57	44.70
Heat Rate (Btu/kWh)	10,951	11,044	10,875	10,220		11,673	10,734	10,756	10,719	10,919	11,062	11,192	11,188
Heat Input (MMBtu)	27,871,686	3,050,480	2,989,676	515,309		1,369,247	3,015,785	3,284,865	3,046,868	2,958,156	3,091,294	2,874,051	1,675,955
Operating Time (hours)	6,696	732	672	119		419	712	744	692	720	731	684	470
CO2 Emissions (tons)	2,859,635	312,980	306,741	52,871		140,484	309,420	337,027	312,608	303,508	317,166	294,877	171,952
CO2 Emissions Rate (lb/MMBtu)	205.2000	205.2002	205.2003	205.2005		205.1994	205.2001	205.2002	205.1998	205.2007	205.1997	205.1997	205.1992
NOX Emissions (lbs)	1,956,792	276,728	289,932	46,550		150,194	138,714	209,555	164,154	146,449	223,465	213,150	97,901
NOX Emissions Rate (lb/MMBtu)	0.0702	0.0907	0.0970	0.0903		0.1097	0.0460	0.0638	0.0539	0.0495	0.0723	0.0742	0.0584
SO2 Emissions (lbs)	2,799,402	296,635	280,796	47,764		177,928	283,120	336,606	303,621	289,529	292,052	292,462	198,890
SO2 Emissions Rate (lb/MMBtu)	0.1004	0.0972	0.0939	0.0927		0.1299	0.0939	0.1025	0.0997	0.0979	0.0945	0.1018	0.1187

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Ghent | Unit Monthly Operations

Unit : Ghent ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0	495.0
Net Generation (MWh)	2,534,622	226,829	243,971	243,833	254,205	204,349	252,744	291,710	294,306	234,902	195,568	68,057	24,148
Gross Generation (MWh)	2,762,473	247,504	264,270	265,305	276,457	223,862	274,639	316,661	318,907	256,676	213,340	75,634	29,218
Capacity Factor (%)	58.45	61.59	73.34	66.21	71.33	55.49	70.92	79.21	79.91	65.91	53.10	19.10	6.56
Heat Rate (Btu/kWh)	10,736	10,548	10,518	10,723	10,731	10,692	10,694	10,755	10,938	11,053	10,471	10,918	11,598
Heat Input (MMBtu)	26,183,411	2,310,954	2,437,362	2,477,339	2,569,502	2,084,801	2,615,558	3,044,346	3,087,355	2,479,040	2,078,718	712,636	285,801
Operating Time (hours)	7,329	744	672	744	720	647	720	744	744	718	522	248	106
CO2 Emissions (tons)	2,686,424	237,106	250,073	254,176	263,631	213,902	268,357	312,352	316,763	254,350	213,275	73,116	29,323
CO2 Emissions Rate (lb/MMBtu)	205.2005	205.2022	205.1999	205.2006	205.1998	205.2012	205.2006	205.2010	205.2004	205.2003	205.1988	205.1996	205.2005
NOX Emissions (lbs)	4,874,509	348,451	449,912	423,907	466,257	346,828	472,898	597,605	556,839	439,550	605,271	111,590	55,401
NOX Emissions Rate (lb/MMBtu)	0.1862	0.1508	0.1846	0.1711	0.1815	0.1664	0.1808	0.1963	0.1804	0.1773	0.2912	0.1566	0.1938
SO2 Emissions (lbs)	9,101,112	549,210	696,680	744,156	812,688	576,305	817,860	1,185,617	1,230,518	983,223	1,210,657	205,425	88,773
SO2 Emissions Rate (lb/MMBtu)	0.3476	0.2377	0.2858	0.3004	0.3163	0.2764	0.3127	0.3894	0.3986	0.3966	0.5824	0.2883	0.3106

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Ghent | Unit Monthly Operations

Unit : Ghent ST 3
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	485.0	485.0	485.0	485.0	485.0	485.0	485.0	485.0	485.0	485.0	485.0	485.0	485.0
Net Generation (MWh)	2,807,537	240,208	254,018	250,853	262,219	251,065	254,699	297,004	294,210	193,446	67,181	241,642	200,992
Gross Generation (MWh)	3,116,331	266,297	280,100	278,178	290,083	279,105	281,962	327,498	326,029	215,618	76,247	268,771	226,443
Capacity Factor (%)	66.08	66.57	77.94	69.52	75.09	69.58	72.94	82.31	81.53	55.40	18.62	69.20	55.70
Heat Rate (Btu/kWh)	10,466	10,390	10,454	10,952	10,429	10,643	10,404	10,360	10,400	10,438	11,487	10,452	9,820
Heat Input (MMBtu)	29,476,557	2,486,259	2,584,500	2,597,631	2,696,656	2,587,985	2,683,783	3,147,144	3,155,254	2,079,427	737,117	2,559,768	2,161,034
Operating Time (hours)	7,942	744	672	744	720	744	720	744	744	574	202	697	638
CO2 Emissions (tons)	3,024,297	255,090	265,170	266,517	276,677	265,528	275,356	322,898	323,728	213,350	75,629	262,632	221,722
CO2 Emissions Rate (lb/MMBtu)	205.2002	205.1995	205.2003	205.1998	205.2003	205.2008	205.2001	205.2008	205.1991	205.2006	205.2012	205.2002	205.2000
NOX Emissions (lbs)	4,597,340	370,282	472,739	441,807	486,875	386,466	467,886	598,294	558,124	317,827	52,366	272,680	171,992
NOX Emissions Rate (lb/MMBtu)	0.1560	0.1489	0.1829	0.1701	0.1805	0.1493	0.1743	0.1901	0.1769	0.1528	0.0710	0.1065	0.0796
SO2 Emissions (lbs)	8,592,800	586,241	729,627	774,988	847,314	655,412	802,128	1,188,674	1,225,960	716,233	101,363	526,250	438,611
SO2 Emissions Rate (lb/MMBtu)	0.2915	0.2358	0.2823	0.2983	0.3142	0.2533	0.2989	0.3777	0.3885	0.3444	0.1375	0.2056	0.2030

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Ghent | Unit Monthly Operations

Unit : Ghent ST 4
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	487.0	487.0	487.0	487.0	487.0	487.0	487.0	487.0	487.0	487.0	487.0	487.0	487.0
Net Generation (MWh)	2,552,598	213,867	263,587	257,201	15,972	113,244	225,738	273,236	278,822	202,402	260,195	240,475	207,859
Gross Generation (MWh)	2,821,422	237,185	288,882	282,134	19,565	126,886	249,902	300,715	306,975	226,157	286,988	265,498	230,535
Capacity Factor (%)	59.83	59.03	80.54	70.99	4.56	31.25	64.38	75.41	76.95	57.72	71.81	68.58	57.37
Heat Rate (Btu/kWh)	10,732	11,130	10,433	10,734	12,391	11,433	10,683	10,484	10,504	10,693	10,689	10,813	10,868
Heat Input (MMBtu)	27,153,916	2,280,869	2,699,306	2,699,280	181,467	1,215,642	2,412,442	2,858,972	2,936,293	2,229,232	2,778,584	2,577,451	2,284,379
Operating Time (hours)	7,690	744	672	744	43	382	720	744	744	689	744	720	744
CO2 Emissions (tons)	2,785,992	234,016	276,948	276,947	18,619	124,724	247,516	293,331	301,264	228,719	285,083	264,447	234,378
CO2 Emissions Rate (lb/MMBtu)	205.2000	205.1994	205.1996	205.2007	205.2011	205.1978	205.1997	205.2001	205.2005	205.1998	205.2004	205.2002	205.2006
NOX Emissions (lbs)	1,739,795	165,966	213,486	198,719	16,784	54,166	72,781	143,938	247,309	101,397	190,061	180,956	154,233
NOX Emissions Rate (lb/MMBtu)	0.0641	0.0728	0.0791	0.0736	0.0925	0.0446	0.0302	0.0503	0.0842	0.0455	0.0684	0.0702	0.0675
SO2 Emissions (lbs)	1,626,673	112,199	160,536	124,139	5,995	94,537	134,708	208,356	181,510	139,559	167,984	169,648	127,503
SO2 Emissions Rate (lb/MMBtu)	0.0599	0.0492	0.0595	0.0460	0.0330	0.0778	0.0558	0.0729	0.0618	0.0626	0.0605	0.0658	0.0558

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Trimble County | Unit Monthly Operations

Unit : Trimble County ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0	511.0
Net Generation (MWh)	2,924,246	236,778	287,347	98,985	314,370	320,488	279,891	297,255	344,373	178,816	(1,231)	250,276	316,898
Gross Generation (MWh)	3,204,449	260,274	313,455	110,293	344,436	349,966	307,158	326,513	376,340	196,688	2,517	273,092	343,717
Capacity Factor (%)	65.33	62.28	83.68	26.04	85.45	84.30	76.07	78.19	90.58	48.60	(0.32)	68.02	83.35
Heat Rate (Btu/kWh)	10,443	10,285	10,565	10,671	10,428	10,524	10,541	10,567	10,392	10,536		10,213	10,138
Heat Input (MMBtu)	28,698,161	2,273,047	2,741,411	973,692	3,103,069	3,368,493	2,736,075	2,922,295	3,391,095	1,782,184	28,651	2,394,848	2,983,300
Operating Time (hours)	6,856	608	627	264	720	744	644	684	744	408	57	613	744
CO2 Emissions (tons)	2,944,434	233,215	281,269	99,901	318,376	345,608	280,722	299,828	347,927	182,852	2,940	245,711	306,086
CO2 Emissions Rate (lb/MMBtu)	205.2002	205.2002	205.2000	205.2012	205.2005	205.2003	205.2004	205.2005	205.2004	205.1999	205.2075	205.1996	205.1996
NOX Emissions (lbs)	2,307,229	248,623	352,670	97,427	277,082	213,687	172,539	173,856	175,490	99,331	9,143	243,313	244,069
NOX Emissions Rate (lb/MMBtu)	0.0804	0.1094	0.1286	0.1001	0.0893	0.0634	0.0631	0.0595	0.0518	0.0557	0.3191	0.1016	0.0818
SO2 Emissions (lbs)	3,215,347	274,308	311,784	111,436	362,502	421,910	435,740	253,121	276,087	147,614	959	214,828	405,059
SO2 Emissions Rate (lb/MMBtu)	0.1120	0.1207	0.1137	0.1144	0.1168	0.1253	0.1593	0.0866	0.0814	0.0828	0.0335	0.0897	0.1358

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Trimble County | Unit Monthly Operations

Unit : Trimble County ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0	760.0
Net Generation (MWh)	5,313,181	422,495	460,176	432,174	47,280	477,887	451,684	488,121	497,922	495,434	528,859	513,831	497,318
Gross Generation (MWh)	5,745,036	456,290	525,490	465,314	58,269	511,733	484,881	523,835	534,788	531,261	566,831	551,390	534,954
Capacity Factor (%)	79.81	74.72	90.10	76.43	8.64	84.52	82.54	86.33	88.06	90.54	93.53	93.90	87.95
Heat Rate (Btu/kWh)	9,218	9,289	9,733	9,216	11,079	9,060	9,144	9,093	9,247	9,099	9,079	9,060	9,253
Heat Input (MMBtu)	47,116,891	3,676,011	4,179,097	3,721,880	489,802	4,130,834	3,941,168	4,314,385	4,451,402	4,320,490	4,729,373	4,620,758	4,541,693
Operating Time (hours)	7,916	619	672	627	120	744	720	744	744	720	744	720	742
CO2 Emissions (tons)	4,941,616	385,540	438,302	390,348	51,370	433,242	413,349	452,493	466,865	453,133	496,017	484,625	476,333
CO2 Emissions Rate (lb/MMBtu)	209.7599	209.7599	209.7594	209.7587	209.7600	209.7599	209.7595	209.7599	209.7607	209.7600	209.7602	209.7598	209.7602
NOX Emissions (lbs)	1,441,669	108,066	128,261	108,708	35,559	136,133	144,225	138,496	114,219	126,820	132,938	128,949	139,295
NOX Emissions Rate (lb/MMBtu)	0.0306	0.0294	0.0307	0.0292	0.0726	0.0330	0.0366	0.0321	0.0257	0.0294	0.0281	0.0279	0.0307
SO2 Emissions (lbs)	2,580,469	241,066	299,809	226,697	34,468	247,226	263,079	206,105	234,253	249,468	228,989	202,490	146,818
SO2 Emissions Rate (lb/MMBtu)	0.0548	0.0656	0.0717	0.0609	0.0704	0.0598	0.0668	0.0478	0.0526	0.0577	0.0484	0.0438	0.0323

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Mill Creek | Unit Monthly Operations

Unit : Mill Creek ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Net Generation (MWh)	1,325,885	175,673	124,388	14,595	153,504	140,902	4,511	41,640	181,564	158,160	84,477	155,240	91,231
Gross Generation (MWh)	1,510,130	196,025	139,398	17,497	174,251	159,677	9,390	52,043	203,345	178,043	97,380	176,533	106,548
Capacity Factor (%)	50.45	78.71	61.70	6.54	71.07	63.13	2.09	18.66	81.35	73.22	37.85	71.87	40.87
Heat Rate (Btu/kWh)	10,648	10,531	10,799	12,080	10,433	10,408	19,057	11,736	10,404	10,567	10,732	10,509	11,048
Heat Input (MMBtu)	13,257,900	1,690,775	1,217,086	158,293	1,536,256	1,402,721	81,607	461,400	1,790,728	1,567,597	860,806	1,541,716	948,915
Operating Time (hours)	6,045	744	492	106	712	744	47	203	744	720	366	673	493
CO2 Emissions (tons)	1,358,776	173,371	124,835	15,969	157,125	143,781	8,364	47,258	183,643	160,770	88,143	158,176	97,341
CO2 Emissions Rate (lb/MMBtu)	204.9761	205.0787	205.1375	201.7650	204.5562	205.0031	204.9761	204.8456	205.1038	205.1162	204.7919	205.1952	205.1634
NOX Emissions (lbs)	3,497,922	448,908	332,827	38,063	423,965	397,753	22,131	121,056	449,912	388,111	214,334	407,668	253,194
NOX Emissions Rate (lb/MMBtu)	0.2638	0.2655	0.2735	0.2405	0.2760	0.2836	0.2712	0.2624	0.2512	0.2476	0.2490	0.2644	0.2668
SO2 Emissions (lbs)	1,238,645	174,591	207,242	9,544	153,820	56,194	2,580	38,838	137,629	101,848	102,745	182,219	71,396
SO2 Emissions Rate (lb/MMBtu)	0.0934	0.1033	0.1703	0.0603	0.1001	0.0401	0.0316	0.0842	0.0769	0.0650	0.1194	0.1182	0.0752

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Mill Creek | Unit Monthly Operations

Unit : Mill Creek ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	297.0	297.0	297.0	297.0	297.0	297.0	297.0	297.0	297.0	297.0	297.0	297.0	297.0
Net Generation (MWh)	1,110,760	163,344	125,988	(380)	127,944	22,148	147,253	111,052	(76)	0	100,184	175,017	138,286
Gross Generation (MWh)	1,241,193	183,685	141,623		141,840	25,898	164,332	124,669			111,653	193,551	153,942
Capacity Factor (%)	42.69	73.92	63.13	(0.17)	59.83	10.02	68.86	50.26	(0.03)	0.00	45.34	81.84	62.58
Heat Rate (Btu/kWh)	10,549	10,592	10,749		10,437	11,696	10,536	10,672			10,441	10,274	10,543
Heat Input (MMBtu)	10,979,725	1,579,366	1,238,639		1,249,577	235,729	1,467,647	1,137,836			996,257	1,695,017	1,379,658
Operating Time (hours)	5,031	663	470		617	143	666	548			460	720	744
CO2 Emissions (tons)	1,125,380	162,014	127,041		127,920	24,149	150,406	116,549			102,064	173,804	141,434
CO2 Emissions Rate (lb/MMBtu)	204.9924	205.1638	205.1292		204.7405	204.8871	204.9623	204.8599			204.8956	205.0759	205.0280
NOX Emissions (lbs)	2,930,606	428,417	338,411		348,676	62,397	391,703	289,178			260,672	447,875	363,277
NOX Emissions Rate (lb/MMBtu)	0.2669	0.2713	0.2732		0.2790	0.2647	0.2669	0.2541			0.2617	0.2642	0.2633
SO2 Emissions (lbs)	1,103,009	176,126	211,941		139,008	18,757	100,598	79,068			81,135	196,401	99,976
SO2 Emissions Rate (lb/MMBtu)	0.1005	0.1115	0.1711		0.1112	0.0796	0.0685	0.0695			0.0814	0.1159	0.0725

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Mill Creek | Unit Monthly Operations

Unit : Mill Creek ST 3
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	394.0	394.0	394.0	394.0	394.0	394.0	394.0	394.0	394.0	394.0	394.0	394.0	394.0
Net Generation (MWh)	2,133,966	218,672	208,793	196,744	202,698	193,882	207,211	219,108	236,444	190,008	66,997	(1,544)	194,953
Gross Generation (MWh)	2,317,821	236,307	226,008	213,983	219,179	210,558	225,214	237,582	255,639	206,530	74,635	0	212,186
Capacity Factor (%)	61.83	74.60	78.86	67.12	71.45	66.14	73.04	74.75	80.66	66.98	22.86	(0.54)	66.51
Heat Rate (Btu/kWh)	10,552	10,692	10,789	10,637	10,423	10,457	10,527	10,336	10,434	10,536	10,669		10,571
Heat Input (MMBtu)	22,689,195	2,306,228	2,194,043	2,100,612	2,146,703	2,085,016	2,219,805	2,322,588	2,503,137	2,039,794	720,734	5,629	2,044,907
Operating Time (hours)	7,406	744	672	741	720	744	720	685	744	667	215	18	735
CO2 Emissions (tons)	2,323,756	236,319	224,879	215,074	219,915	213,606	227,393	237,759	256,449	208,815	73,838	342	209,367
CO2 Emissions Rate (lb/MMBtu)	204.8337	204.9397	204.9905	204.7724	204.8859	204.8964	204.8767	204.7364	204.9020	204.7409	204.8977	121.6288	204.7695
NOX Emissions (lbs)	1,434,556	196,252	169,671	147,061	117,080	111,120	115,157	131,634	139,018	103,826	36,647	260	166,830
NOX Emissions Rate (lb/MMBtu)	0.0632	0.0851	0.0773	0.0700	0.0545	0.0533	0.0519	0.0567	0.0555	0.0509	0.0508	0.0462	0.0816
SO2 Emissions (lbs)	1,533,519	88,449	245,922	100,463	118,755	100,617	160,348	192,043	213,257	145,152	83,100	3	85,412
SO2 Emissions Rate (lb/MMBtu)	0.0676	0.0384	0.1121	0.0478	0.0553	0.0483	0.0722	0.0827	0.0852	0.0712	0.1153	0.0006	0.0418

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

Mill Creek | Unit Monthly Operations

Unit : Mill Creek ST 4
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	486.0	486.0	486.0	486.0	486.0	486.0	486.0	486.0	486.0	486.0	486.0	486.0	486.0
Net Generation (MWh)	2,833,188	261,915	262,429	249,903	262,132	235,302	249,555	276,757	291,641	255,137	179,987	262,020	46,410
Gross Generation (MWh)	3,059,135	281,157	281,636	270,245	282,126	254,075	270,048	297,945	313,585	275,258	196,494	282,341	54,225
Capacity Factor (%)	66.55	72.44	80.35	69.11	74.91	65.08	71.32	76.54	80.66	72.91	49.78	74.88	12.84
Heat Rate (Btu/kWh)	10,381	10,541	10,553	10,658	10,545	10,653	10,263	10,127	10,197	10,296	10,197	10,064	10,984
Heat Input (MMBtu)	29,863,291	2,670,809	2,688,473	2,647,591	2,767,625	2,502,885	2,665,808	2,926,730	3,068,556	2,708,349	1,937,719	2,731,801	546,946
Operating Time (hours)	7,880	744	672	721	693	706	699	744	743	720	536	720	183
CO2 Emissions (tons)	3,058,267	273,689	275,373	270,947	283,566	256,365	273,068	299,920	314,499	277,564	198,407	280,017	54,852
CO2 Emissions Rate (lb/MMBtu)	204.8178	204.9485	204.8544	204.6741	204.9165	204.8557	204.8670	204.9520	204.9820	204.9689	204.7845	205.0056	200.5738
NOX Emissions (lbs)	1,859,461	148,967	171,463	203,998	159,974	147,744	151,008	163,771	161,487	143,915	132,513	185,208	89,412
NOX Emissions Rate (lb/MMBtu)	0.0623	0.0558	0.0638	0.0771	0.0578	0.0590	0.0566	0.0560	0.0526	0.0531	0.0684	0.0678	0.1635
SO2 Emissions (lbs)	2,535,785	138,504	332,136	187,599	211,644	154,323	224,554	256,399	285,899	208,903	210,983	278,044	46,797
SO2 Emissions Rate (lb/MMBtu)	0.0849	0.0519	0.1235	0.0709	0.0765	0.0617	0.0842	0.0876	0.0932	0.0771	0.1089	0.1018	0.0856

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

D.B. Wilson | Unit Monthly Operations

Unit : D B Wilson ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	417.0	417.0	417.0	417.0	417.0	417.0	417.0	417.0	417.0	417.0	417.0	417.0	417.0
Net Generation (MWh)	3,053,599	293,972	213,433	187,614	281,816	252,596	257,965	256,447	293,294	226,977	260,807	249,511	279,167
Gross Generation (MWh)	3,296,345	316,023	231,861	204,557	302,644	271,770	278,474	277,718	315,953	245,839	281,940	268,721	300,845
Capacity Factor (%)	83.59	94.75	76.17	60.47	93.86	81.42	85.92	82.66	94.54	75.60	84.06	83.10	89.98
Heat Rate (Btu/kWh)	10,879	10,786	11,060	11,077	10,632	10,941	10,833	11,002	10,891	10,921	10,788	10,863	10,881
Heat Input (MMBtu)	34,638,232	3,079,142	2,311,546	2,084,446	2,976,148	2,873,063	2,991,670	3,150,840	3,488,861	2,617,140	2,954,286	2,809,419	3,301,671
Operating Time (hours)	8,008	744	586	541	713	658	669	670	744	603	672	668	739
CO2 Emissions (tons)	3,553,884	315,921	237,164	213,863	305,354	294,779	306,945	323,275	357,957	268,518	303,110	288,247	338,751
CO2 Emissions Rate (lb/MMBtu)	205.2001	205.2004	205.1990	205.1991	205.2005	205.2017	205.1997	205.1995	205.2002	205.1999	205.2002	205.2005	205.1998
NOX Emissions (lbs)	3,523,816	225,954	273,673	210,009	298,672	225,497	264,837	245,315	252,384	229,318	256,882	278,177	763,099
NOX Emissions Rate (lb/MMBtu)	0.1017	0.0734	0.1184	0.1008	0.1004	0.0785	0.0885	0.0779	0.0723	0.0876	0.0870	0.0990	0.2311
SO2 Emissions (lbs)	14,314,175	1,118,657	1,036,956	723,319	1,185,759	1,168,556	1,045,409	1,387,306	1,587,024	1,173,756	1,255,462	1,212,703	1,419,268
SO2 Emissions Rate (lb/MMBtu)	0.4132	0.3633	0.4486	0.3470	0.3984	0.4067	0.3494	0.4403	0.4549	0.4485	0.4250	0.4317	0.4299

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

H.L. Spurlock | Unit Monthly Operations

Unit : H L Spurlock ST 1
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Net Generation (MWh)	1,969,888	206,754	151,699	64,561	123,297	191,436	195,463	210,415	212,149	139,013	175,493	169,151	130,457
Gross Generation (MWh)	2,159,099	223,994	166,140	72,739	135,709	208,229	212,261	228,087	230,214	152,628	194,030	187,790	147,278
Capacity Factor (%)	74.96	92.63	75.25	28.93	57.08	85.77	90.49	94.27	95.05	64.36	78.63	78.31	58.45
Heat Rate (Btu/kWh)	11,122	10,139	10,563	11,555	10,701	10,880	10,892	10,764	10,741	11,169	11,724	12,442	12,838
Heat Input (MMBtu)	20,293,368	1,983,794	1,509,483	726,989	1,210,338	1,923,399	1,981,274	2,072,182	2,122,427	1,431,694	1,932,343	1,867,791	1,531,653
Operating Time (hours)	7,847	744	590	315	492	744	720	744	742	552	744	720	740
CO2 Emissions (tons)	2,082,096	203,536	154,873	74,589	124,181	197,339	203,279	212,606	217,762	146,891	198,259	191,635	157,147
CO2 Emissions Rate (lb/MMBtu)	205.1997	205.1991	205.2001	205.2000	205.1999	205.1981	205.2002	205.1999	205.2008	205.1994	205.2001	205.1992	205.1991
NOX Emissions (lbs)	1,809,512	172,910	134,798	65,594	107,759	173,468	179,923	183,548	192,761	116,484	174,352	168,180	139,734
NOX Emissions Rate (lb/MMBtu)	0.0892	0.0872	0.0893	0.0902	0.0890	0.0902	0.0908	0.0886	0.0908	0.0814	0.0902	0.0900	0.0912
SO2 Emissions (lbs)	1,659,209	274,236	179,119	34,327	110,178	128,094	108,570	174,987	187,966	151,562	108,029	128,254	73,886
SO2 Emissions Rate (lb/MMBtu)	0.0818	0.1382	0.1187	0.0472	0.0910	0.0666	0.0548	0.0844	0.0886	0.1059	0.0559	0.0687	0.0482

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

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S&P Capital IQ PRO

H.L. Spurlock | Unit Monthly Operations

Unit : H L Spurlock ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	510.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0	510.0
Net Generation (MWh)	2,625,750	338,953	290,572	253,656	332,762	230,297	270,807	336,395	329,577	225,340	(1,149)	(1,352)	19,892
Gross Generation (MWh)	2,865,415	368,374	316,434	276,745	359,599	250,269	295,358	365,196	358,291	246,576			28,573
Capacity Factor (%)	58.77	89.33	84.78	66.85	90.62	60.69	73.75	88.66	86.86	61.37	(0.30)	(0.37)	5.24
Heat Rate (Btu/kWh)	11,074	11,154	11,325	11,170	10,902	10,851	10,779	10,824	10,974	11,110			18,372
Heat Input (MMBtu)	27,319,136	3,471,571	2,998,605	2,616,039	3,418,430	2,368,964	2,770,150	3,480,610	3,487,526	2,409,838			297,404
Operating Time (hours)	5,972	743	627	596	720	504	609	744	744	519			166
CO2 Emissions (tons)	2,802,942	356,184	307,657	268,405	350,732	243,054	284,217	357,111	357,819	247,250			30,514
CO2 Emissions Rate (lb/MMBtu)	205.1999	205.2002	205.2001	205.1992	205.2007	205.1988	205.1996	205.2004	205.1994	205.2001			205.2013
NOX Emissions (lbs)	2,437,553	315,251	273,324	236,972	306,317	216,713	251,089	310,795	315,608	175,836			35,648
NOX Emissions Rate (lb/MMBtu)	0.0892	0.0908	0.0912	0.0906	0.0896	0.0915	0.0906	0.0893	0.0905	0.0730			0.1199
SO2 Emissions (lbs)	1,923,210	276,060	205,123	144,588	143,349	94,158	213,310	261,581	284,872	274,470			25,699
SO2 Emissions Rate (lb/MMBtu)	0.0704	0.0795	0.0684	0.0553	0.0419	0.0397	0.0770	0.0752	0.0817	0.1139			0.0864

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

H.L. Spurlock | Unit Monthly Operations

Unit : H L Spurlock ST 3
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0
Net Generation (MWh)	1,879,958	197,376	174,220	135,439	141,888	42,863	161,938	109,674	198,663	186,312	195,029	189,001	147,555
Gross Generation (MWh)	2,111,366	220,393	194,918	153,954	160,496	51,679	181,456	124,383	221,580	207,885	217,242	209,546	167,834
Capacity Factor (%)	80.08	98.99	96.74	67.93	73.53	21.50	83.92	55.00	99.63	96.55	97.81	97.95	74.00
Heat Rate (Btu/kWh)	9,902	9,738	9,821	10,045	9,953	10,359	9,869	10,164	9,862	9,845	9,987	9,842	9,841
Heat Input (MMBtu)	18,858,511	1,896,406	1,693,961	1,342,546	1,389,989	458,419	1,632,609	1,135,425	2,009,487	1,912,627	1,989,072	1,887,489	1,510,481
Operating Time (hours)	7,495	744	669	571	556	221	658	453	744	716	744	720	700
CO2 Emissions (tons)	1,934,888	194,572	173,800	137,745	142,614	47,034	167,507	116,497	206,174	196,237	204,077	193,657	154,976
CO2 Emissions Rate (lb/MMBtu)	205.2005	205.2013	205.1990	205.1998	205.2011	205.2000	205.2012	205.2035	205.2001	205.2018	205.1978	205.2002	205.2009
NOX Emissions (lbs)	1,123,305	111,692	102,741	81,392	82,956	33,800	96,706	66,395	115,808	109,475	115,965	108,786	97,587
NOX Emissions Rate (lb/MMBtu)	0.0596	0.0589	0.0607	0.0606	0.0597	0.0737	0.0592	0.0585	0.0576	0.0572	0.0583	0.0576	0.0646
SO2 Emissions (lbs)	2,590,771	257,033	246,715	192,007	184,936	58,435	226,483	157,050	258,579	271,140	264,436	259,339	214,617
SO2 Emissions Rate (lb/MMBtu)	0.1374	0.1355	0.1456	0.1430	0.1330	0.1275	0.1387	0.1383	0.1287	0.1418	0.1329	0.1374	0.1421

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

H.L. Spurlock | Unit Monthly Operations

Unit : H L Spurlock ST 4
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0	268.0
Net Generation (MWh)	1,953,333	198,172	177,503	164,004	160,642	141,361	187,581	190,148	196,264	190,710	92,907	88,156	165,885
Gross Generation (MWh)	2,205,136	221,425	198,409	185,526	182,741	161,174	211,186	214,249	220,450	214,144	106,859	102,470	186,503
Capacity Factor (%)	83.20	99.39	98.56	82.25	83.25	70.90	97.21	95.36	98.43	98.83	46.60	45.69	83.20
Heat Rate (Btu/kWh)	9,927	9,616	9,814	10,049	10,171	9,915	9,682	10,037	10,085	9,962	10,150	10,520	9,550
Heat Input (MMBtu)	18,557,742	1,839,418	1,655,191	1,555,956	1,531,462	1,354,555	1,773,974	1,831,535	1,853,225	1,807,387	899,635	877,003	1,578,401
Operating Time (hours)	7,770	744	672	656	680	576	720	742	744	720	361	411	744
CO2 Emissions (tons)	1,904,025	188,724	169,823	159,641	157,128	138,978	182,011	187,916	190,141	185,438	92,302	89,980	161,944
CO2 Emissions Rate (lb/MMBtu)	205.2000	205.1991	205.2002	205.2002	205.2004	205.2006	205.2011	205.2002	205.1999	205.2005	205.1981	205.1987	205.1998
NOX Emissions (lbs)	1,109,299	105,362	97,418	98,002	91,490	80,138	103,952	106,930	107,679	106,795	53,510	58,080	99,943
NOX Emissions Rate (lb/MMBtu)	0.0598	0.0573	0.0589	0.0630	0.0597	0.0592	0.0586	0.0584	0.0581	0.0591	0.0595	0.0662	0.0633
SO2 Emissions (lbs)	1,762,842	167,814	148,613	148,224	162,729	138,188	151,635	176,308	174,017	177,403	86,455	109,058	122,399
SO2 Emissions Rate (lb/MMBtu)	0.0950	0.0912	0.0898	0.0953	0.1063	0.1020	0.0855	0.0963	0.0939	0.0982	0.0961	0.1244	0.0775

This data is sourced from EPA's Continuous Emissions Monitoring System (CEMS) and the EIA 923 monthly and annual filings. The CEMS data is released quarterly and available for larger fossil fired facilities. The EIA 923 monthly filing represents a sampling of the annual filers and will therefore be a subset of the total filers. The annual filing has a significant lag of between 9 and 13 months dependent on the EIA.

S&P Capital IQ PRO

East Bend | Unit Monthly Operations

Unit : East Bend ST 2
Periods : Latest Calendar Year

	2021Y	01/21	02/21	03/21	04/21	05/21	06/21	07/21	08/21	09/21	10/21	11/21	12/21
Operating Capacity (MW)	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0	600.0
Net Generation (MWh)	2,542,673	280,323	360,347	325,032	260,186	250,711	360,958	329,547	307,006	56,073	(3,171)	(4,767)	20,428
Gross Generation (MWh)	2,796,938	306,902	390,339	354,168	283,799	274,916	392,095	359,283	335,034	65,963			34,439
Capacity Factor (%)	48.38	62.80	89.37	72.81	60.23	56.16	83.56	73.82	68.77	12.98	(0.71)	(1.10)	4.58
Heat Rate (Btu/kWh)	11,040	11,182	10,783	10,611	10,941	11,635	10,810	11,460	10,814	8,607			17,486
Heat Input (MMBtu)	28,863,965	3,099,880	3,886,963	3,633,813	2,878,708	2,873,951	4,094,001	3,768,207	3,502,625	704,484			421,334
Operating Time (hours)	5,504	588	672	744	550	553	720	714	611	154			198
CO2 Emissions (tons)	2,961,446	318,048	398,803	372,829	295,356	294,868	420,044	386,619	359,370	72,280			43,229
CO2 Emissions Rate (lb/MMBtu)	205.2002	205.2002	205.2000	205.1999	205.2003	205.2005	205.1999	205.2005	205.2005	205.2005			205.2004
NOX Emissions (lbs)	2,931,666	307,917	356,592	360,930	365,941	286,649	366,255	407,310	297,816	98,438			83,818
NOX Emissions Rate (lb/MMBtu)	0.1016	0.0993	0.0917	0.0993	0.1271	0.0997	0.0895	0.1081	0.0850	0.1397			0.1989
SO2 Emissions (lbs)	3,511,353	396,132	441,883	400,417	280,236	384,582	555,520	498,626	428,325	75,239			50,394
SO2 Emissions Rate (lb/MMBtu)	0.1217	0.1278	0.1137	0.1102	0.0973	0.1338	0.1357	0.1323	0.1223	0.1068			0.1196

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