COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

AN EXAMINATION OF THE APPLICATION	)	
OF THE FUEL ADJUSTMENT CLAUSE OF	)	
KENTUCKY POWER COMPANY FROM	)	**CASE NO. 2014-00225**
NOVEMBER 1, 2013 THROUGH APRIL 30, 2014	)	

KENTUCKY POWER COMPANY RESPONSE TO
COMMISSION STAFF'S FIRST SET OF DATA REQUESTS

August 27, 2014

VERIFICATION

The undersigned, Daniel L. Moyer, being duly sworn, deposes and says he is the Plant Manager-Kammer/Mitchell for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief.

Daniel L. Moyer

Daniel L. Moyer

STATE OF WEST VIRGINIA)
) Case No. 2014-00225
COUNTY OF MARSHALL)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Daniel L. Moyer, this the 25th day of August, 2014.

Notary Public

My Commission Expires: 2-10-2021

OFFICIAL SEAL
STATE OF WEST VIRGINIA
NOTARY PUBLIC
Rita Kramer
AEP Kammer Mitchell Plant
P.O. Box K
Moundsville, WV 26041
My Commission Expires Feb. 10, 2021

VERIFICATION

The undersigned, John A. Rogness III, being duly sworn, deposes and says he is the Director Regulatory Services for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his/her information, knowledge and belief.

John A. Rogness III

COMMONWEALTH OF KENTUCKY)
) Case No. 2014-00225
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John A. Rogness III, this the 27th day of August 2014.

Judy K Rosquist 481393
Notary Public

My Commission Expires: January 23, 2017

VERIFICATION

The undersigned, Aaron M. Sink, being duly sworn, deposes and says he is Plant Manager – Big Sandy for Kentucky Power Company, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Aaron M. Sink

Aaron M. Sink

COMMONWEALTH OF KENTUCKY	)	
	)	CASE NO. 2014-00225
COUNTY OF BOYD	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Aaron M. Sink, this the 22nd day of August 2014.

Diana K. Frasher

Notary Public

My Commission Expires: 03-21-2017

VERIFICATION

The undersigned, Charles F. West, being duly sworn, deposes and says he is the Manager, Fuel Emissions & Logistics, for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Charles F. West

STATE OF OHIO	)	
	)	Case No. 2014-00225
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Charles F. West, this the 25 day of August 2014.

Notary Public

Gina L. Beyer
Notary Public, State of Ohio
My Commission Expires 07-01-2016

My Commission Expires: 7/1/16

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY	)	
	)	Case No. 2014-00225
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 27th day of August 2014.

Ann Dawn Clark

Notary Public

NOTARY PUBLIC STATE OF OHIO

Ann Dawn Clark
Notary Public-State of Ohio
My Commission Expires
November 16, 2015

My Commission Expires: November 16, 2015

Kentucky Power Company

REQUEST

For the period from November 1, 2013, through April 30, 2014, list each vendor from whom coal was purchased and the quantities and the nature of each purchase (i.e., spot or contract). For the period under review in total, provide the percentage of purchases that were spot versus contract. For contract purchases, state whether the contract has been filed with the Commission. If no, explain why it has not been filed.

RESPONSE

Please see Attachment 1 for a listing of each vendor from which coal was purchased, the quantities, the nature of each coal purchase, and the percentage of purchases that were spot versus contract during the period from November 1, 2013 to April 30, 2014.

Kentucky Power's share of purchases for the Mitchell Plant have been included for the period from January 1, 2014 through April 30, 2014.

Contracts for all contract purchases have been filed with the Commission.

WITNESS: Charles F West

Kentucky Power Coal Purchases

Counterparty	Name of Purchase	Total Tons
Beech Fork Processing, Inc.	Contract	45,744
Beech Fork Processing, Inc.	Spot	8,266
EDF Trading North America, LLC	Spot	18,577
Maple Coal Co	Spot	31,969
Mercuria Energy Trading, Inc.	Spot	7,605
Ohio Valley Resources, Inc.	Contract	144,065
Patriot Coal Sales, LLC	Spot	43,326
Peabody COALTRADE, LLC	Spot	4,387
Rhino Energy LLC	Contract	132,781
RWE Supply & Trading GmbH	Spot	7,074
S.M.& J., Inc.	Contract	83,758
Southern Coal Sales Corporation	Contract	294,139
Trafigura AG	Spot	60,322
	Grand Total	882,014

Total Contract	79%
Total Spot	21%

Kentucky Power Company

REQUEST

For the period from November 1, 2013, through April 30, 2014, list each vendor from whom natural gas was purchased for generation and the quantities and the nature of each purchase (i.e., spot or contract). For contract purchases, state whether the contract has been filed with the Commission. If no, explain why it has not been filed.

RESPONSE

Kentucky Power did not purchase natural gas for generation during the review period from November 1, 2013 to April 30, 2014.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

State whether Kentucky Power engages in hedging activities for its coal or natural gas purchases used for generation. If yes, describe the hedging activities in detail.

RESPONSE

Kentucky Power has not engaged in any hedging activities for its coal purchases during the review period.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

For each generating station or unit for which a separate coal pile is maintained, state, for the period from November 1, 2013, through April 30, 2014, the actual amount of coal burned in tons, the actual amount of coal deliveries in tons, the total kWh generated, and the actual capacity factor at which the plant operated.

RESPONSE

Big Sandy Plant Statistics
11/1/13 -- 4/30/14

Coal Burned in tons	1,004,070
Coal Delivered in tons	519,674
Net Generation in MWh	2,381,393
Net Capacity Factor	50.85 %

Mitchell Plant Statistics
(Kentucky Power's share)
1/1/14 -- 4/30/14

Coal Burned in tons	581,171
Coal Delivered in tons	362,340
Net Generation in MWh	1,459,966
Net Capacity Factor	65.04 %

WITNESS: Daniel L Moyer and Aaron M Sink

Kentucky Power Company

REQUEST

List all firm power commitments for Kentucky Power from November 1, 2013, through April 30, 2014, for (a) purchases and (b) sales. This list shall identify the electric utility, the amount of commitment in MW, and the purpose of the commitment (i.e., peaking, emergency).

RESPONSE

(a) Firm power purchases for Kentucky Power for the period from November 1, 2013 through April 30, 2014:

AEP Generating Company (Unit Power Agreement - Rockport Plant Base Load)	393 MW

(b) Firm power sales: Commitments for Kentucky Power Company, other than retail jurisdictional customers, are the Cities of Olive Hill and Vanceburg, Kentucky as shown below. The numbers listed below represent the customer's peak load during the review period from November 1, 2013 to April 30, 2014. The cities use the power for load-following service to their citizens.

City of Olive Hill	6.8 MW
City of Vanceburg	15.9 MW

WITNESS: John A Rogness III

Kentucky Power Company

REQUEST

Provide a monthly billing summary of sales to all electric utilities for the period November 1, 2013, through April 30, 2014.

RESPONSE

Please see Attachment 1 for a monthly billing summary of sales to all electric utilities for the period November 1, 2013 through April 30, 2014.

A listing of the tracking code acronyms as previously requested in the March 9, 2012 Hearing in Case No. 2011-00482 is being supplied as pages 30-31 of Attachment 1.

WITNESS: John A Rogness III

Kentucky Power Company
Sales to Electric Utilities
Billing Summary

Pd	Year	Unit	Ref	Trkg Cd	Account	Revenue	KWH Metered
11	2013	117			4470001	1,600.50	0
11	2013	117		ECSO2	4470001	-146.30	0
11	2013	117	SO2	ECSO2	4470001	8.87	0
					4470001 Total	1,463.07	0
11	2013	117		ECSO2	4470002	-15,338.53	0
11	2013	117	BKSYSEXCES	BUCK	4470002	-481.58	0
11	2013	117	HR-NF	MISO	4470002	-9,777.73	0
11	2013	117	HR-NF	TVAM	4470002	-16.05	0
11	2013	117	MO-F	AMPO	4470002	12,088.01	0
11	2013	117	MO-F	APN5	4470002	2,848.99	0
11	2013	117	MO-F	BARC2	4470002	1,638.39	0
11	2013	117	MO-F	CECA2	4470002	-11,954.68	0
11	2013	117	MO-F	EDFT2	4470002	3,479.68	0
11	2013	117	MO-F	EUTL2	4470002	2,031.05	0
11	2013	117	MO-F	INGS2	4470002	1,534.35	0
11	2013	117	MO-F	NCEM	4470002	65,685.53	0
11	2013	117	MO-F	WGES	4470002	5,734.64	0
11	2013	117	OPC Var	OPCVR	4470002	55,607.78	0
11	2013	117	SO2	ECSO2	4470002	276.78	0
11	2013	117	YR-F	BPPA2	4470002	1,137.04	0
11	2013	117	YR-F	EDFT2	4470002	5,992.70	0
11	2013	117	YR-F	EKPM	4470002	23,250.30	0
					4470002 Total	143,736.67	0
11	2013	117		AMPO	4470006	0.00	0
11	2013	117		ARON	4470006	189,887.40	4,575,600
11	2013	117		BANG2	4470006	8,292.47	145,000
11	2013	117		BARR2	4470006	28,519.78	437,000
11	2013	117		BLOO2	4470006	16,972.39	293,000
11	2013	117		BMES	4470006	7,684.50	148,000
11	2013	117		BPPA2	4470006	-13.54	-4,000
11	2013	117		CADO2	4470006	4,487.40	77,000
11	2013	117		COLS2	4470006	272,562.32	4,239,000
11	2013	117		CORN2	4470006	4,724.33	81,000
11	2013	117		CWEL2	4470006	13,815.17	280,000
11	2013	117		DEL	4470006	-109.35	0
11	2013	117		DEOI2	4470006	-90.00	0
11	2013	117		DTET	4470006	-1,224.00	0
11	2013	117		EDFT2	4470006	0.00	0
11	2013	117		GLOU2	4470006	1,096.41	5,000
11	2013	117		HAME2	4470006	1,613.71	30,000
11	2013	117		HREA2	4470006	41,915.48	546,000
11	2013	117		MEDF2	4470006	43,503.85	687,000
11	2013	117		MISO	4470006	-25,121.31	19,000
11	2013	117		MPPA	4470006	20,544.44	305,040
11	2013	117		PPLT2	4470006	0.00	0
11	2013	117		RICE2	4470006	53,214.21	885,000
11	2013	117		RPLY	4470006	5,685.29	100,000
11	2013	117		SEBE2	4470006	17,587.66	373,000
11	2013	117		SHEL	4470006	10,182.93	140,000
11	2013	117		SOY	4470006	14,824.94	274,536
11	2013	117		SPOO2	4470006	11,179.57	185,000
11	2013	117		TOHI2	4470006	7,452.11	121,000
11	2013	117		TREM2	4470006	4,365.82	91,000
11	2013	117		WAKE2	4470006	4,875.10	83,000
11	2013	117		WPSC	4470006	109,757.21	2,287,800
11	2013	117		WSTR2	4470006	189,342.17	2,436,000
11	2013	117	BRK COMM	MSUI2	4470006	-675.92	0
11	2013	117	BRK COMM	UBSF2	4470006	-74.08	0
					4470006 Total	1,056,778.46	18,839,976
11	2013	117			4470010	79.58	0
11	2013	117		DPC	4470010	-17.83	0
11	2013	117		MISO	4470010	-343,861.31	-11,087,000
11	2013	117		PJM	4470010	657.75	0

11	2013	117		PJM	4470010	92.92	0
11	2013	117		PJM	4470010	292.06	0
11	2013	117		PJM	4470010	16.99	0
11	2013	117		PJM	4470010	-183,951.46	-4,273,413
11	2013	117		PJM	4470010	-106,859.59	-2,446,079
11	2013	117		PJM	4470010	40.06	0
11	2013	117		PJM	4470010	0.14	0
11	2013	117		PJM	4470010	406.35	0
11	2013	117		PJM	4470010	168.86	0
11	2013	117		PJM	4470010	12.61	0
11	2013	117		PJM	4470010	-8,224.91	-111,345
11	2013	117		PJM	4470010	0.52	0
11	2013	117		PJM	4470010	-5,856.06	-145,437
11	2013	117		PJM	4470010	-925.55	-3,733
11	2013	117		PJM	4470010	-1,248.85	-30,943
11	2013	117		PJM	4470010	-3,427.08	-92,616
11	2013	117		PJM	4470010	27.05	0
11	2013	117		PJM	4470010	-20,593.76	-534,924
11	2013	117		TVAM	4470010	0.00	0
11	2013	117		WR	4470010	-138.17	0
11	2013	117	BRK COMM	MSUI2	4470010	-675.92	0
11	2013	117	BRK COMM	UBSF2	4470010	-132.94	0
					4470010 Total	-674,118.54	-18,725,490
11	2013	117		BUCK	4470028	262.94	0
11	2013	117		ECSO2	4470028	15,338.53	0
11	2013	117	BKSYSEXCES	BUCK	4470028	44,615.99	1,073,093
11	2013	117	HR-NF	MISO	4470028	47,975.25	1,324,763
11	2013	117	HR-NF	TVAM	4470028	16.04	0
11	2013	117	MO-F	AMPO	4470028	14,901.57	516,548
11	2013	117	MO-F	APN5	4470028	6,571.51	229,098
11	2013	117	MO-F	BARC2	4470028	4,462.37	152,901
11	2013	117	MO-F	CECA2	4470028	147,425.23	5,096,710
11	2013	117	MO-F	EDFT2	4470028	11,368.16	399,920
11	2013	117	MO-F	EUTL2	4470028	3,942.91	137,459
11	2013	117	MO-F	INGS2	4470028	4,492.68	157,795
11	2013	117	MO-F	NCEM	4470028	131,430.17	4,581,955
11	2013	117	MO-F	WGES	4470028	13,143.02	458,196
11	2013	117	OPC Var	OPCVR	4470028	-55,607.78	0
11	2013	117	SO2	ECSO2	4470028	-276.78	0
11	2013	117	YR-F	BPPA2	4470028	1,877.78	66,628
11	2013	117	YR-F	EDFT2	4470028	10,355.72	366,556
11	2013	117	YR-F	EKPM	4470028	64,723.24	2,290,978
					4470028 Total	467,018.55	16,852,600
11	2013	117			4470035	20,798.17	758,914
11	2013	117		ECSO2	4470035	146.30	0
11	2013	117	SO2	ECSO2	4470035	-8.87	0
					4470035 Total	20,935.60	758,914
11	2013	117		TVAM	4470066	-4.00	0
					4470066 Total	-4.00	0
11	2013	117		MSUI2	4470081	1,002.50	0
11	2013	117		MSUI2	4470081	-1,423.03	0
11	2013	117		MSUI2	4470081	31,397.27	0
11	2013	117		UBSF2	4470081	5,402.86	0
11	2013	117		UBSF2	4470081	3,703.69	0
					4470081 Total	40,083.29	0
11	2013	117		AMEM	4470082	16,905.80	0
11	2013	117		ARON	4470082	-47,878.38	0
11	2013	117		BARC2	4470082	-8,965.69	0
11	2013	117		BPEC	4470082	-11,581.33	0
11	2013	117		CEI	4470082	0.00	0
11	2013	117		CONC	4470082	9,493.37	0
11	2013	117		DBET	4470082	-9,162.80	0
11	2013	117		DPLG	4470082	10,372.58	0
11	2013	117		DTET	4470082	-733.39	0
11	2013	117		EDFT2	4470082	1,416.59	0

11	2013	117		EMAH2	4470082	10,358.04	0
11	2013	117		ENAM	4470082	4,178.99	0
11	2013	117		EPLU	4470082	22,698.31	0
11	2013	117		EXGN	4470082	-150,659.37	0
11	2013	117		FESC	4470082	3,188.27	0
11	2013	117		IESI2	4470082	1,065.92	0
11	2013	117		INGS2	4470082	-20.46	0
11	2013	117		IPWC2	4470082	2,957.72	0
11	2013	117		JPMV2	4470082	-54,244.15	0
11	2013	117		MECB	4470082	2,367.54	0
11	2013	117		MSCG	4470082	-35,010.56	0
11	2013	117		MSUI2	4470082	-25,060.39	0
11	2013	117		NAGP	4470082	3,029.14	0
11	2013	117		NASIA	4470082	-3,485.15	0
11	2013	117		NEXT2	4470082	6,273.80	0
11	2013	117		SES	4470082	671.68	0
11	2013	117		UBSF2	4470082	-113,849.99	0
11	2013	117		UECO2	4470082	-775.17	0
					4470082 Total	-366,449.08	0
11	2013	117	SPOT MARKE	PJM	4470089	-48,772.21	0
					4470089 Total	-48,772.21	0
11	2013	117			4470098	108.79	0
11	2013	117		PJM	4470098	-7,179.82	0
11	2013	117		PJM	4470098	65,393.14	0
11	2013	117		PJM	4470098	-205.18	0
11	2013	117		PJM	4470098	-6,989.30	0
11	2013	117		PJM	4470098	16,585.27	0
11	2013	117		PJM	4470098	69.75	0
11	2013	117		PJM	4470098	15,574.15	0
					4470098 Total	83,356.80	0
11	2013	117		NRG	4470099	1,784.48	0
11	2013	117		PJM	4470099	35,768.31	0
					4470099 Total	37,552.79	0
11	2013	117		PJM	4470100	4,502.36	0
					4470100 Total	4,502.36	0
11	2013	117	SPOT MARKE	PJM	4470103	3,383,102.95	90,412,427
					4470103 Total	3,383,102.95	90,412,427
11	2013	117		PJM	4470106	-0.77	0
					4470106 Total	-0.77	0
11	2013	117		PJM	4470107	-86.20	0
11	2013	117		PJM	4470107	-7.89	0
11	2013	117		PJM	4470107	-1,423.89	0
					4470107 Total	-1,517.98	0
11	2013	117		PJM	4470109	6,640.34	0
					4470109 Total	6,640.34	0
11	2013	117		PJM	4470110	-198.79	0
11	2013	117		PJM	4470110	84.01	0
					4470110 Total	-114.78	0
11	2013	117		PJM	4470115	13,689.33	0
11	2013	117		PJM	4470115	-0.18	0
11	2013	117		PJM	4470115	1,768.65	0
					4470115 Total	15,457.80	0
11	2013	117			4470124	-0.01	0
11	2013	117		PJM	4470124	-0.04	0
					4470124 Total	-0.05	0
11	2013	117			4470126	6,279.54	0
11	2013	117		PJM	4470126	443.34	0
11	2013	117		PJM	4470126	-46,885.62	0
11	2013	117		PJM	4470126	48,004.94	0
11	2013	117		PJM	4470126	-20,513.09	0
11	2013	117		PJM	4470126	-2,373.36	0
11	2013	117		PJM	4470126	-82,101.43	0
					4470126 Total	-97,145.68	0
11	2013	117	AEP-POOL		4470128	955,589.00	33,168,302
					4470128 Total	955,589.00	33,168,302

11	2013	117		PJM	4470131	0.00	0
					4470131 Total	0.00	0
11	2013	117		MSUI2	4470143	1,920.93	0
11	2013	117		UBSF2	4470143	20,085.66	0
11	2013	117	BRK COMM	UBSF2	4470143	0.00	0
					4470143 Total	22,006.59	0
11	2013	117		NASIA	4470144	96.00	0
					4470144 Total	96.00	0
11	2013	117		UBS	4470168	-5,088.64	0
					4470168 Total	-5,088.64	0
11	2013	117		DEOI2	4470170	11,712.36	236,000
11	2013	117		FESC	4470170	266,180.21	5,237,000
					4470170 Total	277,892.57	5,473,000
11	2013	117		PJM	4470174	6,688.21	0
					4470174 Total	6,688.21	0
11	2013	117		NASIA	4470175	-813,220.83	0
					4470175 Total	-813,220.83	0
11	2013	117		NASIA	4470176	813,220.83	0
					4470176 Total	813,220.83	0
11	2013	117		NASIA	4470180	-4,522.84	0
					4470180 Total	-4,522.84	0
11	2013	117		NASIA	4470181	4,522.84	0
					4470181 Total	4,522.84	0
11	2013	117			4470206	-3,239.74	0
11	2013	117		BUCK	4470206	0.00	0
11	2013	117		PJM	4470206	138.85	0
11	2013	117		PJM	4470206	4,199.96	0
11	2013	117		PJM	4470206	39,634.88	0
					4470206 Total	40,733.95	0
11	2013	117		PJM	4470209	-49,292.98	0
11	2013	117		PJM	4470209	15,942.17	0
11	2013	117		PJM	4470209	-23,840.96	0
11	2013	117		PJM	4470209	-5,250.02	0
11	2013	117		PJM	4470209	-109,356.03	0
					4470209 Total	-171,797.82	0
11	2013	117		PJM	4470214	25.04	0
					4470214 Total	25.04	0
11	2013	117		PJM	4470220	-535.02	0
					4470220 Total	-535.02	0
11	2013	117		PJM	4470221	-1,533.38	0
					4470221 Total	-1,533.38	0
11	2013	117		PJM	4470222	35,056.74	0
					4470222 Total	35,056.74	0
11	2013	117		PJM	5550039	-762.29	0
11	2013	117		PJM	5550039	8.58	0
11	2013	117		PJM	5550039	1,780.53	0
					5550039 Total	1,026.82	0
11	2013	117		BPEC	5550099	60.01	0
11	2013	117		DBET	5550099	-9,562.05	0
11	2013	117		EXGN	5550099	-778.21	0
11	2013	117		NASIA	5550099	3,485.15	0
11	2013	117		PJM	5550099	2,337.13	0
11	2013	117		PJM	5550099	92.92	0
11	2013	117		PJM	5550099	0.45	0
11	2013	117		PJM	5550099	102.93	0
11	2013	117		PJM	5550099	-8,540.06	-242,539
11	2013	117		PJM	5550099	1.79	0
11	2013	117		PJM	5550099	1.26	0
11	2013	117		PJM	5550099	0.42	0
11	2013	117		PJM	5550099	-202,728.71	-5,739,648
11	2013	117		PJM	5550099	43.74	0
11	2013	117		PJM	5550099	32.44	0
11	2013	117		PJM	5550099	8.83	0
11	2013	117		PJM	5550099	18.08	0
11	2013	117		UBSF2	5550099	-9,744.79	0

					5550099 Total	-225,168.67	-5,982,187
11	2013	117		AMEM	5550100	-120.49	0
11	2013	117		CMS	5550100	-2,264.32	0
11	2013	117		DYPM	5550100	-248.37	0
11	2013	117		EDFT2	5550100	-503.32	0
11	2013	117		JPMV2	5550100	-4,089.26	0
					5550100 Total	-7,225.76	0
11	2013	117		PJM	5550107	-6,504.12	0
11	2013	117		PJM	5550107	-920.92	0
11	2013	117		PJM	5550107	-145.60	0
11	2013	117		PJM	5550107	-1,123.92	0
					5550107 Total	-8,694.56	0
11	2013	110		SOLS2	5570007	-6,164.35	-13
11	2013	110		TITA2	5570007	-12.07	0
					5570007 Total	-6,176.42	-13
11	2013	117			5614000	0.00	0
11	2013	117		PJM	5614000	0.00	0
11	2013	117		PJM	5614000	-0.49	0
11	2013	117		PJM	5614000	-90.84	0
11	2013	117		PJM	5614000	-14,580.90	0
					5614000 Total	-14,672.23	0
11	2013	180		PJM	5614008	0.00	0
					5614008 Total	0.00	0
11	2013	117		PJM	5618000	0.00	0
11	2013	117		PJM	5618000	-18.24	0
11	2013	117		PJM	5618000	-14.12	0
11	2013	117		PJM	5618000	-14.00	0
11	2013	117		PJM	5618000	-1.44	0
11	2013	117		PJM	5618000	-0.28	0
11	2013	117		PJM	5618000	-3,304.23	0
					5618000 Total	-3,352.31	0
11	2013	117			5757000	0.00	0
11	2013	117		PJM	5757000	0.00	0
11	2013	117		PJM	5757000	-675.14	0
11	2013	117		PJM	5757000	-45.38	0
11	2013	117		PJM	5757000	-519.63	0
11	2013	117		PJM	5757000	-52.99	0
11	2013	117		PJM	5757000	-10.18	0
11	2013	117		PJM	5757000	-13,701.06	0
					5757000 Total	-15,004.38	0
November Total						**4,952,371.32**	**140,797,529**
12	2013	117			4470001	739.90	0
12	2013	117		ECSO2	4470001	-52.56	0
12	2013	117		NASIA	4470001	0.00	0
12	2013	117	SO2	ECSO2	4470001	-11.00	0
					4470001 Total	676.34	0
12	2013	117		ECSO2	4470002	-67,322.70	0
12	2013	117		NASIA	4470002	-0.01	0
12	2013	117	BKSYSEXCES	BUCK	4470002	38,073.71	0
12	2013	117	HR-NF	MISO	4470002	3,431.55	0
12	2013	117	HR-NF	OVPS	4470002	1.85	0
12	2013	117	MO-F	AMPO	4470002	30,194.51	0
12	2013	117	MO-F	APN5	4470002	3,516.97	0
12	2013	117	MO-F	BARC2	4470002	2,124.30	0
12	2013	117	MO-F	CECA2	4470002	50,084.64	0
12	2013	117	MO-F	EDFT2	4470002	4,306.34	0
12	2013	117	MO-F	EUTL2	4470002	2,442.10	0
12	2013	117	MO-F	INGS2	4470002	2,240.48	0
12	2013	117	MO-F	NCEM	4470002	79,322.83	0
12	2013	117	MO-F	WGES	4470002	7,071.76	0
12	2013	117	OPC Var	OPCVR	4470002	481,446.73	0
12	2013	117	SO2	ECSO2	4470002	-5,835.04	0
12	2013	117	YR-F	BPPA2	4470002	1,456.32	0

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12	2013	117	YR-F	EDFT2	4470002	7,079.24	0
12	2013	117	YR-F	EKPM	4470002	29,588.13	0
					4470002 Total	669,223.71	0
12	2013	117		AMPO	4470006	0.00	0
12	2013	117		ARON	4470006	196,216.98	4,728,120
12	2013	117		BANG2	4470006	11,305.48	181,000
12	2013	117		BARR2	4470006	27,700.97	453,000
12	2013	117		BLOO2	4470006	20,930.34	345,000
12	2013	117		BMES	4470006	8,841.54	173,000
12	2013	117		BPPA2	4470006	-350.54	-2,000
12	2013	117		CADO2	4470006	5,605.53	87,000
12	2013	117		CISO	4470006	2.57	0
12	2013	117		COLS2	4470006	298,520.38	4,635,000
12	2013	117		CORN2	4470006	5,906.31	94,000
12	2013	117		CWEL2	4470006	16,038.71	327,000
12	2013	117		DEL	4470006	0.00	0
12	2013	117		DEOI2	4470006	-308.00	0
12	2013	117		DTET	4470006	-964.00	0
12	2013	117		EDFT2	4470006	0.00	0
12	2013	117		GLOU2	4470006	1,482.78	11,000
12	2013	117		HAME2	4470006	2,003.53	37,000
12	2013	117		HREA2	4470006	49,495.50	622,000
12	2013	117		MEDF2	4470006	40,978.16	690,000
12	2013	117		MISO	4470006	-33,640.59	0
12	2013	117		MPPA	4470006	21,571.67	320,292
12	2013	117		NASIA	4470006	0.00	0
12	2013	117		RICE2	4470006	59,115.17	961,000
12	2013	117		RPLY	4470006	5,359.79	104,000
12	2013	117		SEBE2	4470006	17,551.41	373,000
12	2013	117		SHEL	4470006	12,625.88	173,000
12	2013	117		SOY	4470006	19,931.31	369,098
12	2013	117		SPOO2	4470006	12,401.10	207,000
12	2013	117		TOHI2	4470006	9,619.75	156,000
12	2013	117		TREM2	4470006	6,408.64	101,000
12	2013	117		WAKE2	4470006	6,002.32	97,000
12	2013	117		WPSC	4470006	113,415.78	2,364,060
12	2013	117		WSTR2	4470006	212,943.29	2,772,000
12	2013	117	BRK COMM	MSUI2	4470006	672.30	0
12	2013	117	BRK COMM	UBSF2	4470006	74.08	0
12	2013	117	PBAS	UBSF2	4470006	-12.96	0
12	2013	117	PMAC	MSUI2	4470006	-1,130.93	0
12	2013	117	PMWE	MSUI2	4470006	-17.12	0
12	2013	117	PMWE	UBSF2	4470006	-368.57	0
12	2013	117	PNEA	MSUI2	4470006	-46.08	0
12	2013	117	PNEA	UBSF2	4470006	-21.22	0
					4470006 Total	1,145,861.26	20,378,570
12	2013	117		DPC	4470010	-17.83	0
12	2013	117		MISO	4470010	-431,132.26	-11,871,000
12	2013	117		PJM	4470010	-63.56	0
12	2013	117		PJM	4470010	14.92	0
12	2013	117		PJM	4470010	78.63	0
12	2013	117		PJM	4470010	-216,772.89	-4,651,399
12	2013	117		PJM	4470010	-129,373.74	-2,755,679
12	2013	117		PJM	4470010	156.68	0
12	2013	117		PJM	4470010	183.58	0
12	2013	117		PJM	4470010	-1.52	0
12	2013	117		PJM	4470010	-11,738.60	-160,817
12	2013	117		PJM	4470010	-0.30	0
12	2013	117		PJM	4470010	-27,219.21	-165,888
12	2013	117		PJM	4470010	-4,878.45	-7,935
12	2013	117		PJM	4470010	-1,457.23	-34,454
12	2013	117		PJM	4470010	-4,551.68	-103,393
12	2013	117		PJM	4470010	-27,455.29	-612,472
12	2013	117	BRK COMM	MSUI2	4470010	672.30	0
12	2013	117	BRK COMM	UBSF2	4470010	102.44	0

12	2013	117	PBAS	UBSF2	4470010	-12.96	0
12	2013	117	PMAC	MSUI2	4470010	-1,130.93	0
12	2013	117	PMWE	MSUI2	4470010	-8.58	0
12	2013	117	PMWE	UBSF2	4470010	-396.42	0
12	2013	117	PNEA	MSUI2	4470010	-46.08	0
12	2013	117	PNEA	UBSF2	4470010	-21.22	0
					4470010 Total	-855,070.20	-20,363,037
12	2013	117		BUCK	4470028	116.31	0
12	2013	117		ECSO2	4470028	67,322.70	0
12	2013	117		NASIA	4470028	0.00	0
12	2013	117	BKSYSEXCES	BUCK	4470028	106,622.33	3,030,523
12	2013	117	HR-NF	MISO	4470028	52,404.38	1,588,115
12	2013	117	HR-NF	OVPS	4470028	3.87	127
12	2013	117	MO-F	AMPO	4470028	29,973.72	1,151,547
12	2013	117	MO-F	APN5	4470028	6,204.04	236,406
12	2013	117	MO-F	BARC2	4470028	4,082.96	155,570
12	2013	117	MO-F	CECA2	4470028	191,076.93	7,320,960
12	2013	117	MO-F	EDFT2	4470028	9,811.14	373,064
12	2013	117	MO-F	EUTL2	4470028	3,722.43	141,844
12	2013	117	MO-F	INGS2	4470028	4,955.72	189,125
12	2013	117	MO-F	NCEM	4470028	124,080.89	4,728,120
12	2013	117	MO-F	WGES	4470028	12,408.09	472,812
12	2013	117	OPC Var	OPCVR	4470028	-481,446.73	0
12	2013	117	SO2	ECSO2	4470028	5,835.04	0
12	2013	117	YR-F	BPPA2	4470028	1,953.04	75,347
12	2013	117	YR-F	EDFT2	4470028	9,790.68	378,250
12	2013	117	YR-F	EKPM	4470028	61,191.78	2,364,060
					4470028 Total	210,109.32	22,205,870
12	2013	117			4470035	7,207.10	272,371
12	2013	117		ECSO2	4470035	52.56	0
12	2013	117		NASIA	4470035	0.00	0
12	2013	117	SO2	ECSO2	4470035	11.00	0
					4470035 Total	7,270.66	272,371
12	2013	117		ENTE	4470066	-398.00	0
12	2013	117		TVAM	4470066	-8.00	0
					4470066 Total	-406.00	0
12	2013	117		MSUI2	4470081	-30,920.49	0
12	2013	117		MSUI2	4470081	1,586.21	0
12	2013	117		MSUI2	4470081	29,018.84	0
12	2013	117		UBSF2	4470081	3,200.62	0
					4470081 Total	2,885.18	0
12	2013	117		AMEM	4470082	8,991.66	0
12	2013	117		ARON	4470082	-38,205.35	0
12	2013	117		BARC2	4470082	-6,334.27	0
12	2013	117		BPEC	4470082	-3,461.94	0
12	2013	117		CONC	4470082	1,131.59	0
12	2013	117		DBET	4470082	-8,703.46	0
12	2013	117		DPLG	4470082	7,832.46	0
12	2013	117		DTET	4470082	-1,290.96	0
12	2013	117		EDFT2	4470082	1,292.52	0
12	2013	117		EMAH2	4470082	2,204.57	0
12	2013	117		ENAM	4470082	-1,684.23	0
12	2013	117		EPLU	4470082	13,905.55	0
12	2013	117		EXGN	4470082	-103,794.68	0
12	2013	117		FESC	4470082	-615.89	0
12	2013	117		IESI2	4470082	-539.07	0
12	2013	117		INGS2	4470082	-177.78	0
12	2013	117		IPWC2	4470082	0.00	0
12	2013	117		JPMV2	4470082	-46,199.86	0
12	2013	117		MECB	4470082	575.08	0
12	2013	117		MSCG	4470082	-25,716.10	0
12	2013	117		MSUI2	4470082	36,016.44	0
12	2013	117		NAGP	4470082	1,966.97	0
12	2013	117		NASIA	4470082	337.45	0
12	2013	117		NEXT2	4470082	2,353.62	0

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12	2013	117		OTP	4470082	-2.97	0
12	2013	117		SES	4470082	132.72	0
12	2013	117		UBSF2	4470082	-87,631.36	0
12	2013	117		UECO2	4470082	1,652.51	0
					4470082 Total	-245,964.78	0
12	2013	117		NASIA	4470089	0.00	0
12	2013	117	SPOT MARKE	PJM	4470089	1,696,540.82	0
					4470089 Total	1,696,540.82	0
12	2013	117		NASIA	4470098	0.00	0
12	2013	117		PJM	4470098	20,251.04	0
12	2013	117		PJM	4470098	111,505.74	0
12	2013	117		PJM	4470098	-1,263.19	0
12	2013	117		PJM	4470098	-8,507.07	0
12	2013	117		PJM	4470098	18,766.30	0
12	2013	117		PJM	4470098	-2,146.70	0
12	2013	117		PJM	4470098	-308.26	0
12	2013	117		PJM	4470098	-171,566.54	0
					4470098 Total	-33,268.68	0
12	2013	117		NASIA	4470099	0.00	0
12	2013	117		NRG	4470099	1,843.97	0
12	2013	117		PJM	4470099	39,468.48	0
					4470099 Total	41,312.45	0
12	2013	117		NASIA	4470100	0.00	0
12	2013	117		PJM	4470100	10,352.33	0
					4470100 Total	10,352.33	0
12	2013	117		NASIA	4470103	0.00	0
12	2013	117	SPOT MARKE	PJM	4470103	6,884,461.99	212,270,223
					4470103 Total	6,884,461.99	212,270,223
12	2013	117		PJM	4470106	-300.18	0
					4470106 Total	-300.18	0
12	2013	117		PJM	4470107	6.92	0
12	2013	117		PJM	4470107	-8.42	0
12	2013	117		PJM	4470107	-1,446.68	0
					4470107 Total	-1,448.18	0
12	2013	117		PJM	4470109	1,343.73	0
					4470109 Total	1,343.73	0
12	2013	117		PJM	4470110	-190.03	0
12	2013	117		PJM	4470110	-205.07	0
					4470110 Total	-395.10	0
12	2013	117		NASIA	4470115	0.00	0
12	2013	117		PJM	4470115	29,126.93	0
12	2013	117		PJM	4470115	45.87	0
12	2013	117		PJM	4470115	-0.34	0
12	2013	117		PJM	4470115	749.40	0
12	2013	117		PJM	4470115	154.77	0
					4470115 Total	30,076.63	0
12	2013	117		NASIA	4470124	0.01	0
12	2013	117		PJM	4470124	-0.07	0
					4470124 Total	-0.06	0
12	2013	117			4470126	2,213.14	0
12	2013	117		PJM	4470126	-2,767.97	0
12	2013	117		PJM	4470126	-164,671.73	0
12	2013	117		PJM	4470126	71,488.19	0
12	2013	117		PJM	4470126	-168,401.66	0
12	2013	117		PJM	4470126	-57,967.75	0
12	2013	117		PJM	4470126	-147,628.37	0
					4470126 Total	-467,736.15	0
12	2013	117		NASIA	4470128	0.00	0
12	2013	117	AEP-POOL		4470128	6,878,609.00	228,778,060
					4470128 Total	6,878,609.00	228,778,060
12	2013	117		PJM	4470131	0.00	0
					4470131 Total	0.00	0
12	2013	117		MSUI2	4470143	280.25	0
12	2013	117		UBSF2	4470143	8,850.05	0
12	2013	117	HRMG	UBSF2	4470143	-1.02	0

					4470143 Total	9,129.28	0
12	2013	117		NASIA	4470144	92.00	0
					4470144 Total	92.00	0
12	2013	117		DEOI2	4470170	13,598.27	274,000
12	2013	117		FESC	4470170	303,019.05	5,961,000
12	2013	117		NASIA	4470170	0.00	0
12	2013	117	NMSO		4470170	25,483.79	0
					4470170 Total	342,101.11	6,235,000
12	2013	117		NASIA	4470174	0.00	0
12	2013	117		PJM	4470174	-3,645.93	0
					4470174 Total	-3,645.93	0
12	2013	117		NASIA	4470175	819,752.06	0
					4470175 Total	819,752.06	0
12	2013	117		NASIA	4470176	-819,752.06	0
					4470176 Total	-819,752.06	0
12	2013	117		NASIA	4470180	-17,058.61	0
					4470180 Total	-17,058.61	0
12	2013	117		NASIA	4470181	17,058.61	0
					4470181 Total	17,058.61	0
12	2013	117		BUCK	4470206	0.00	0
12	2013	117		NASIA	4470206	0.00	0
12	2013	117		PJM	4470206	-146,564.76	0
12	2013	117		PJM	4470206	314.94	0
12	2013	117		PJM	4470206	8,789.83	0
12	2013	117		PJM	4470206	-719.63	0
12	2013	117		PJM	4470206	-61.89	0
12	2013	117		PJM	4470206	-112.00	0
12	2013	117		PJM	4470206	243,008.88	0
					4470206 Total	104,655.37	0
12	2013	117		NASIA	4470209	0.00	0
12	2013	117		PJM	4470209	0.00	0
12	2013	117		PJM	4470209	-163,934.49	0
12	2013	117		PJM	4470209	39,015.84	0
12	2013	117		PJM	4470209	-100,605.66	0
12	2013	117		PJM	4470209	-47,520.38	0
12	2013	117		PJM	4470209	-259,672.59	0
					4470209 Total	-532,717.28	0
12	2013	117		PJM	4470214	243.82	0
12	2013	117		PJM	4470214	0.29	0
12	2013	117		PJM	4470214	0.04	0
12	2013	117		PJM	4470214	80.34	0
					4470214 Total	324.49	0
12	2013	117		PJM	4470220	2,567.31	0
12	2013	117		PJM	4470220	38.17	0
12	2013	117		PJM	4470220	215.25	0
					4470220 Total	2,820.73	0
12	2013	117		PJM	4470221	0.00	0
12	2013	117		PJM	4470221	20,144.39	0
12	2013	117		PJM	4470221	4,240.22	0
12	2013	117		PJM	4470221	1,729.55	0
12	2013	117		PJM	4470221	18.98	0
12	2013	117		PJM	4470221	1,770.43	0
					4470221 Total	27,903.57	0
12	2013	117		PJM	4470222	36,630.12	0
					4470222 Total	36,630.12	0
12	2013	117		PJM	5550039	-504.96	0
12	2013	117		PJM	5550039	23.76	0
12	2013	117		PJM	5550039	5,453.61	0
					5550039 Total	4,972.41	0
12	2013	117		BPEC	5550099	3,957.01	0
12	2013	117		DBET	5550099	-6,648.71	0
12	2013	117		EXGN	5550099	-438.01	0
12	2013	117		NASIA	5550099	-337.45	0
12	2013	117		PJM	5550099	-2,624.86	0
12	2013	117		PJM	5550099	14.92	0

12	2013	117		PJM	5550099	94.61	0
12	2013	117		PJM	5550099	31.09	0
12	2013	117		PJM	5550099	-11,094.50	-277,459
12	2013	117		PJM	5550099	93.00	0
12	2013	117		PJM	5550099	267.69	0
12	2013	117		PJM	5550099	10.98	0
12	2013	117		PJM	5550099	-228,740.77	-6,440,939
12	2013	117		PJM	5550099	51.99	0
12	2013	117		PJM	5550099	36.64	0
12	2013	117		UBSF2	5550099	-8,121.85	0
					5550099 Total	-253,448.22	-6,718,398
12	2013	117		AMEM	5550100	-120.49	0
12	2013	117		CMS	5550100	-2,264.32	0
12	2013	117		DYPM	5550100	-248.37	0
12	2013	117		EDFT2	5550100	-503.32	0
12	2013	117		JPMV2	5550100	-4,089.26	0
12	2013	117	NMSO		5550100	-35,265.13	0
					5550100 Total	-42,490.89	0
12	2013	117		PJM	5550107	-7,665.57	0
12	2013	117		PJM	5550107	-1,085.37	0
12	2013	117		PJM	5550107	-428.16	0
12	2013	117		PJM	5550107	-1,324.62	0
					5550107 Total	-10,503.72	0
12	2013	110		MECB	5570007	-603.34	-257
12	2013	110		PJM	5570007	-95.33	0
12	2013	110		TFS2	5570007	-146.10	-15
					5570007 Total	-844.77	-272
12	2013	117		PJM	5614000	0.00	0
12	2013	117		PJM	5614000	-89.83	0
12	2013	117		PJM	5614000	-112.99	0
12	2013	117		PJM	5614000	-109.97	0
12	2013	117		PJM	5614000	-11.38	0
12	2013	117		PJM	5614000	-1.64	0
12	2013	117		PJM	5614000	-28,987.58	0
					5614000 Total	-29,313.39	0
12	2013	180		PJM	5614008	0.00	0
					5614008 Total	0.00	0
12	2013	117		PJM	5618000	0.00	0
12	2013	117		PJM	5618000	-69.15	0
12	2013	117		PJM	5618000	-30.28	0
12	2013	117		PJM	5618000	-90.63	0
12	2013	117		PJM	5618000	-15.11	0
12	2013	117		PJM	5618000	-0.68	0
12	2013	117		PJM	5618000	-7,600.80	0
					5618000 Total	-7,806.65	0
12	2013	117		PJM	5757000	0.00	0
12	2013	117		PJM	5757000	-2,421.05	0
12	2013	117		PJM	5757000	-85.30	0
12	2013	117		PJM	5757000	-3,187.39	0
12	2013	117		PJM	5757000	-544.14	0
12	2013	117		PJM	5757000	-26.75	0
12	2013	117		PJM	5757000	-28,169.98	0
					5757000 Total	-34,434.61	0
December Total						**15,587,557.71**	**463,058,387**
1	2014	117			4470001	-263.44	0
1	2014	117		ECSO2	4470001	6.85	0
1	2014	117	SO2	ECSO2	4470001	-5.24	0
					4470001 Total	-261.83	0
1	2014	117		ECSO2	4470002	-7,099.57	0
1	2014	117	BKSYSEXCES	BUCK	4470002	-7,793.49	0
1	2014	117	HR-NF	MISO	4470002	-3,466.20	0
1	2014	117	HR-NF	OVPS	4470002	-0.25	0
1	2014	117	MO-F	AMPO	4470002	-1,205.02	0

1	2014	117	MO-F	APN5	4470002	-220.67	0
1	2014	117	MO-F	BARC2	4470002	-182.07	0
1	2014	117	MO-F	CECA2	4470002	-7,448.01	0
1	2014	117	MO-F	EDFT2	4470002	-308.93	0
1	2014	117	MO-F	EUTL2	4470002	-132.40	0
1	2014	117	MO-F	INGS2	4470002	-176.54	0
1	2014	117	MO-F	NCEM	4470002	-4,413.49	0
1	2014	117	MO-F	WGES	4470002	-441.34	0
1	2014	117	OPC Var	OPCVR	4470002	241,909.09	0
1	2014	117	SO2	ECSO2	4470002	-587.74	0
1	2014	117	YR-F	BPPA2	4470002	-55.61	0
1	2014	117	YR-F	EDFT2	4470002	-293.67	0
1	2014	117	YR-F	EKPM	4470002	-1,835.48	0
					4470002 Total	206,248.61	0
1	2014	117		AMPO	4470006	0.00	0
1	2014	117		ARON	4470006	0.00	0
1	2014	117		BANG2	4470006	-10,892.26	-176,000
1	2014	117		BARR2	4470006	-30,996.38	-459,000
1	2014	117		BLOO2	4470006	-20,649.86	-346,000
1	2014	117		BMES	4470006	-8,790.03	-172,000
1	2014	117		CADO2	4470006	-5,536.17	-87,000
1	2014	117		COLS2	4470006	-295,113.82	-4,634,000
1	2014	117		CORN2	4470006	-5,839.92	-93,000
1	2014	117		CWEL2	4470006	-15,935.34	-325,000
1	2014	117		DEOI2	4470006	-416.00	0
1	2014	117		DTET	4470006	-912.00	0
1	2014	117		EDFT2	4470006	0.00	0
1	2014	117		GLOU2	4470006	-1,454.89	-10,000
1	2014	117		HAME2	4470006	-1,994.63	-37,000
1	2014	117		HREA2	4470006	-48,956.04	-624,000
1	2014	117		MEDF2	4470006	-45,797.61	-704,000
1	2014	117		MISO	4470006	-33,597.43	0
1	2014	117		MPPA	4470006	0.00	0
1	2014	117		PJM	4470006	47,138.85	0
1	2014	117		RICE2	4470006	-59,645.38	-972,000
1	2014	117		RPLY	4470006	-5,354.62	-104,000
1	2014	117		SEBE2	4470006	-17,373.37	-369,000
1	2014	117		SHEL	4470006	-12,606.47	-185,000
1	2014	117		SOY	4470006	0.00	0
1	2014	117		SPOO2	4470006	-12,759.24	-216,000
1	2014	117		TOHI2	4470006	-9,290.07	-150,000
1	2014	117		TREM2	4470006	-5,642.77	-99,000
1	2014	117		WAKE2	4470006	-5,859.58	-96,000
1	2014	117		WPSC	4470006	0.00	0
1	2014	117		WSTR2	4470006	-212,072.96	-2,763,000
1	2014	117	PBAS	BANG2	4470006	23,783.11	365,000
1	2014	117	PBAS	BARR2	4470006	58,974.32	963,000
1	2014	117	PBAS	BLOO2	4470006	42,027.37	693,000
1	2014	117	PBAS	BMES	4470006	18,993.89	372,000
1	2014	117	PBAS	CADO2	4470006	11,514.60	176,000
1	2014	117	PBAS	CECA2	4470006	48,001.62	1,228,920
1	2014	117	PBAS	CORN2	4470006	11,205.71	181,000
1	2014	117	PBAS	CWEL2	4470006	15,937.07	325,000
1	2014	117	PBAS	HAME2	4470006	4,121.53	76,000
1	2014	117	PBAS	MEDF2	4470006	89,121.16	1,481,000
1	2014	117	PBAS	RICE2	4470006	121,583.20	1,975,000
1	2014	117	PBAS	RPLY	4470006	11,701.60	228,000
1	2014	117	PBAS	SEBE2	4470006	17,151.80	364,000
1	2014	117	PBAS	SPOO2	4470006	22,693.55	372,000
1	2014	117	PBAS	TOHI2	4470006	19,657.25	316,000
1	2014	117	PBAS	TREM2	4470006	11,949.70	198,000
1	2014	117	PBAS	WAKE2	4470006	11,595.18	192,000
1	2014	117	PHRD	MISO	4470006	25,265.07	673,000
1	2014	117	PMAC	MSUI2	4470006	-496.21	0
1	2014	117	PMRT	MISO	4470006	3,940.11	0

1	2014	117	PMWE	AMPO	4470006	155,506.65	2,617,957
1	2014	117	PMWE	BARC2	4470006	13,462.84	279,893
1	2014	117	PMWE	BPPA2	4470006	-671.34	-2,000
1	2014	117	PMWE	COLS2	4470006	618,819.24	9,516,000
1	2014	117	PMWE	EDFT2	4470006	17,641.43	445,621
1	2014	117	PMWE	EKPM	4470006	89,565.70	2,332,440
1	2014	117	PMWE	GLOU2	4470006	4,901.65	60,000
1	2014	117	PMWE	HREA2	4470006	106,085.20	1,348,000
1	2014	117	PMWE	INGS2	4470006	7,002.26	184,087
1	2014	117	PMWE	MPPA	4470006	22,296.62	331,056
1	2014	117	PMWE	MSUI2	4470006	-79.39	0
1	2014	117	PMWE	NCEM	4470006	205,721.21	4,664,880
1	2014	117	PMWE	SHEL	4470006	34,183.76	545,000
1	2014	117	PMWE	UBSF2	4470006	-126.27	0
1	2014	117	PMWE	WPSC	4470006	138,406.99	3,498,660
1	2014	117	PMWE	WSTR2	4470006	443,842.94	5,824,000
1	2014	117	PMWS	EXGN	4470006	43,864.92	1,103,520
1	2014	117	PNEA	MSUI2	4470006	0.00	0
1	2014	117	PNEA	UBSF2	4470006	-4.01	0
1	2014	117	PNEA	WGES	4470006	46,683.79	1,166,220
1	2014	117	PSHD	MSUI2	4470006	-46.92	0
1	2014	117	PSHD	OVPS	4470006	1,790.47	6,472
1	2014	117	PSHD	UBSF2	4470006	-26.61	0
					4470006 Total	1,697,194.77	31,479,726
1	2014	117		DPC	4470010	17.83	0
1	2014	117		MISO	4470010	420,007.02	11,514,000
1	2014	117		PJM	4470010	-27,186.86	0
1	2014	117		PJM	4470010	16.07	0
1	2014	117		PJM	4470010	5.23	0
1	2014	117		PJM	4470010	-517,255.37	-4,872,207
1	2014	117		PJM	4470010	-328,219.23	-3,046,844
1	2014	117		PJM	4470010	-0.06	0
1	2014	117		PJM	4470010	10,994.11	0
1	2014	117		PJM	4470010	244.66	0
1	2014	117		PJM	4470010	-0.85	0
1	2014	117		PJM	4470010	-56,421.68	-343,577
1	2014	117		PJM	4470010	-1,382,334.99	0
1	2014	117		PJM	4470010	1.05	0
1	2014	117		PJM	4470010	-18,234.66	-182,102
1	2014	117		PJM	4470010	-6,670.36	-50,945
1	2014	117		PJM	4470010	-3,911.92	-38,509
1	2014	117		PJM	4470010	-11,429.40	-114,062
1	2014	117		PJM	4470010	12.93	0
1	2014	117		PJM	4470010	-64,041.35	-685,133
1	2014	117	OVEC	OVPS	4470010	0.00	0
1	2014	117	PBAS	DPC	4470010	-35.42	0
1	2014	117	PBAS	MISO	4470010	-380,064.81	-7,629,000
1	2014	117	PHET	TVAM	4470010	-1,692.90	-94,050
1	2014	117	PHRE	TVAM	4470010	-6,166.98	-206,408
1	2014	117	PHRT	TVAM	4470010	-60,172.17	-2,125,733
1	2014	117	PMAC	MSUI2	4470010	-496.21	0
1	2014	117	PMRT	MISO	4470010	-525,866.56	-11,612,000
1	2014	117	PMWE	MISO	4470010	-14.03	0
1	2014	117	PMWE	MSUI2	4470010	-87.16	0
1	2014	117	PMWE	UBSF2	4470010	-136.94	0
1	2014	117	PMWS	EXGN	4470010	-45,244.32	-1,103,520
1	2014	117	PNEA	MSUI2	4470010	0.00	0
1	2014	117	PNEA	UBSF2	4470010	-4.01	0
1	2014	117	PSHD	MSUI2	4470010	-31.82	0
1	2014	117	PSHD	UBSF2	4470010	-24.81	0
					4470010 Total	-3,004,445.97	-20,590,090
1	2014	117		BUCK	4470028	39.23	0
1	2014	117		ECSO2	4470028	7,099.57	0
1	2014	117	BKSYSEXCES	BUCK	4470028	2,837.36	-114,730
1	2014	117	HR-NF	MISO	4470028	3,466.20	0

1	2014	117	HR-NF	OVPS	4470028	0.25	0
1	2014	117	MO-F	AMPO	4470028	1,205.02	0
1	2014	117	MO-F	APN5	4470028	220.67	0
1	2014	117	MO-F	BARC2	4470028	182.07	0
1	2014	117	MO-F	CECA2	4470028	7,448.02	0
1	2014	117	MO-F	EDFT2	4470028	308.93	0
1	2014	117	MO-F	EUTL2	4470028	132.40	0
1	2014	117	MO-F	INGS2	4470028	176.54	0
1	2014	117	MO-F	NCEM	4470028	4,413.49	0
1	2014	117	MO-F	WGES	4470028	441.35	0
1	2014	117	OPC Var	OPCVR	4470028	-241,909.09	0
1	2014	117	SO2	ECSO2	4470028	587.74	0
1	2014	117	YR-F	BPPA2	4470028	55.61	0
1	2014	117	YR-F	EDFT2	4470028	293.68	0
1	2014	117	YR-F	EKPM	4470028	1,835.47	0
					4470028 Total	-211,165.49	-114,730
1	2014	117			4470035	9,532.42	212,225
1	2014	117		ECSO2	4470035	-6.85	0
1	2014	117	SO2	ECSO2	4470035	5.24	0
					4470035 Total	9,530.81	212,225
1	2014	117		ENTE	4470066	-118.00	0
1	2014	117		TVAM	4470066	5.00	0
					4470066 Total	-113.00	0
1	2014	117		MSUI2	4470081	-0.21	0
1	2014	117	KBAS	MSUI2	4470081	4,726.95	0
1	2014	117	KBAS	UBSF2	4470081	-2,194.50	0
1	2014	117	KCP	MSUI2	4470081	39.50	0
					4470081 Total	2,571.74	0
1	2014	117		AMEM	4470082	-8,991.66	0
1	2014	117		ARON	4470082	38,198.24	0
1	2014	117		BARC2	4470082	6,334.24	0
1	2014	117		BPEC	4470082	3,461.94	0
1	2014	117		CONC	4470082	-1,131.59	0
1	2014	117		DBET	4470082	8,703.46	0
1	2014	117		DPLG	4470082	-7,832.46	0
1	2014	117		DTET	4470082	1,290.96	0
1	2014	117		EDFT2	4470082	-1,292.52	0
1	2014	117		EMAH2	4470082	-2,204.55	0
1	2014	117		ENAM	4470082	1,684.23	0
1	2014	117		EPLU	4470082	-13,905.55	0
1	2014	117		EXGN	4470082	103,794.68	0
1	2014	117		FESC	4470082	615.89	0
1	2014	117		IESI2	4470082	539.07	0
1	2014	117		INGS2	4470082	177.75	0
1	2014	117		JPMV2	4470082	46,199.86	0
1	2014	117		MECB	4470082	-575.08	0
1	2014	117		MSCG	4470082	25,715.02	0
1	2014	117		MSUI2	4470082	-47,627.30	0
1	2014	117		NAGP	4470082	-1,966.97	0
1	2014	117		NASIA	4470082	-3,743.73	0
1	2014	117		NEXT2	4470082	-2,350.00	0
1	2014	117		SES	4470082	-134.22	0
1	2014	117		UBSF2	4470082	66,290.10	0
1	2014	117		UECO2	4470082	-1,652.51	0
1	2014	117	PBAS	AMEM	4470082	1,312.03	0
1	2014	117	PBAS	ARON	4470082	-51,001.59	0
1	2014	117	PBAS	BARC2	4470082	-3,901.69	0
1	2014	117	PBAS	BPEC	4470082	1,219.58	0
1	2014	117	PBAS	CONC	4470082	-202,470.47	0
1	2014	117	PBAS	DBET	4470082	-8,975.25	0
1	2014	117	PBAS	DPLG	4470082	7,832.46	0
1	2014	117	PBAS	EDFT2	4470082	-11,231.28	0
1	2014	117	PBAS	EMAH2	4470082	-1,741.71	0
1	2014	117	PBAS	ENAM	4470082	-24.66	0
1	2014	117	PBAS	EPLU	4470082	-57,764.61	0

1	2014	117	PBAS	EXGN	4470082	201,482.14	0
1	2014	117	PBAS	IESI2	4470082	599.98	0
1	2014	117	PBAS	MECB	4470082	-8,081.59	0
1	2014	117	PBAS	MSCG	4470082	31,294.17	0
1	2014	117	PBAS	MSUI2	4470082	36,714.78	0
1	2014	117	PBAS	NEXT2	4470082	96,590.59	0
1	2014	117	PBAS	SES	4470082	-3,613.65	0
1	2014	117	PBAS	UBSF2	4470082	335,617.62	0
1	2014	117	PBAS	UECO2	4470082	1,652.51	0
1	2014	117	PHET	MSUI2	4470082	0.00	0
1	2014	117	PHET	UBSF2	4470082	-1,712.67	0
1	2014	117	PHRD	UBSF2	4470082	-2,275.31	0
1	2014	117	PHRE	MSUI2	4470082	0.00	0
1	2014	117	PHRE	UBSF2	4470082	0.00	0
1	2014	117	PHRT	MSUI2	4470082	1,738.27	0
1	2014	117	PHRT	UBSF2	4470082	-4,470.11	0
1	2014	117	PMWE	AMEM	4470082	-79,435.99	0
1	2014	117	PMWE	ARON	4470082	-18,781.57	0
1	2014	117	PMWE	BARC2	4470082	23,055.29	0
1	2014	117	PMWE	BPEC	4470082	-4,681.52	0
1	2014	117	PMWE	DBET	4470082	19,656.25	0
1	2014	117	PMWE	DTET	4470082	-1,290.96	0
1	2014	117	PMWE	EMAH2	4470082	3,946.33	0
1	2014	117	PMWE	ENAM	4470082	-1,790.31	0
1	2014	117	PMWE	EPLU	4470082	-36,710.25	0
1	2014	117	PMWE	EXGN	4470082	249,195.84	0
1	2014	117	PMWE	FESC	4470082	-615.89	0
1	2014	117	PMWE	IESI2	4470082	-3,412.03	0
1	2014	117	PMWE	INGS2	4470082	-4,032.11	0
1	2014	117	PMWE	JPMV2	4470082	103,031.12	0
1	2014	117	PMWE	MECB	4470082	-21,431.75	0
1	2014	117	PMWE	MSUI2	4470082	-321,049.21	0
1	2014	117	PMWE	NEXT2	4470082	6,355.94	0
1	2014	117	PMWE	UBSF2	4470082	855,139.04	0
1	2014	117	PNEA	ARON	4470082	-2,393.06	0
1	2014	117	PNEA	DBET	4470082	-394.32	0
1	2014	117	PNEA	ENAM	4470082	130.76	0
1	2014	117	PNEA	EXGN	4470082	11,048.56	0
1	2014	117	PNEA	MSUI2	4470082	-47,148.19	0
1	2014	117	PNEA	NAGP	4470082	1,966.97	0
1	2014	117	PNEA	UBSF2	4470082	87,021.94	0
1	2014	117	PSHD	MSUI2	4470082	1,147.50	0
1	2014	117	PSHD	UBSF2	4470082	-610.40	0
					4470082 Total	1,386,304.82	0
1	2014	117	SPOT MARKE	PJM	4470089	35,447,972.55	0
					4470089 Total	35,447,972.55	0
1	2014	117		PJM	4470098	-90,112.70	0
1	2014	117		PJM	4470098	17,536.35	0
1	2014	117		PJM	4470098	-41.36	0
1	2014	117		PJM	4470098	141.61	0
1	2014	117		PJM	4470098	1,800.58	0
1	2014	117		PJM	4470098	-1,377,484.00	0
1	2014	117		PJM	4470098	-28.00	0
1	2014	117		PJM	4470098	-12,731.18	0
					4470098 Total	-1,460,918.70	0
1	2014	117		NRG	4470099	0.00	0
1	2014	117		PJM	4470099	12,372.78	0
1	2014	117		PJM	4470099	36,939.09	0
1	2014	117	NRMG	BUCK	4470099	1,332.41	0
1	2014	117	NRMG	NRG	4470099	1,819.30	0
					4470099 Total	52,463.58	0
1	2014	117		PJM	4470100	973.93	0
1	2014	117		PJM	4470100	-5.17	0
					4470100 Total	968.76	0
1	2014	117	SPOT MARKE	PJM	4470103	19,821,812.21	513,319,077

					4470103 Total	19,821,812.21	513,319,077
1	2014	117		PJM	4470106	-15.33	0
					4470106 Total	-15.33	0
1	2014	117		PJM	4470107	2,448.63	0
1	2014	117		PJM	4470107	-7.54	0
1	2014	117		PJM	4470107	-1,512.24	0
					4470107 Total	928.85	0
1	2014	117		PJM	4470109	-210,110.25	0
1	2014	117		PJM	4470109	-235.42	0
					4470109 Total	-210,345.67	0
1	2014	117		PJM	4470110	-175.65	0
1	2014	117		PJM	4470110	0.00	0
					4470110 Total	-175.65	0
1	2014	117		PJM	4470115	-9,073.17	0
1	2014	117		PJM	4470115	-4.78	0
1	2014	117		PJM	4470115	-1,594.94	0
1	2014	117		PJM	4470115	468.08	0
					4470115 Total	-10,204.81	0
1	2014	117		PJM	4470124	0.14	0
					4470124 Total	0.14	0
1	2014	117		PJM	4470126	-478,655.62	0
1	2014	117		PJM	4470126	6,231.14	0
1	2014	117		PJM	4470126	-3,933.00	0
1	2014	117		PJM	4470126	-22,947.12	0
1	2014	117		PJM	4470126	-12,481,993.88	0
1	2014	117		PJM	4470126	11,739.77	0
					4470126 Total	-12,969,558.71	0
1	2014	117	AEP-POOL		4470128	5,479,520.00	27,368,166
					4470128 Total	5,479,520.00	27,368,166
1	2014	117		PJM	4470131	0.00	0
					4470131 Total	0.00	0
1	2014	117		MSUI2	4470143	1.30	0
1	2014	117		UBSF2	4470143	47.73	0
1	2014	117	HRMG	MSUI2	4470143	0.00	0
1	2014	117	HRMG	UBSF2	4470143	0.00	0
					4470143 Total	49.03	0
1	2014	117		NASIA	4470144	69.00	0
					4470144 Total	69.00	0
1	2014	117		DEOI2	4470170	-13,758.57	-277,000
1	2014	117		FESC	4470170	-304,829.48	-5,997,000
1	2014	117	NPJM	DEOI2	4470170	31,706.25	638,000
1	2014	117	NPJM	FESC	4470170	620,684.80	12,211,000
					4470170 Total	333,803.00	6,575,000
1	2014	117		PJM	4470174	80.78	0
					4470174 Total	80.78	0
1	2014	117		NASIA	4470175	65,562.36	0
					4470175 Total	65,562.36	0
1	2014	117		NASIA	4470176	-65,562.36	0
					4470176 Total	-65,562.36	0
1	2014	117		NASIA	4470180	-78,477.14	0
					4470180 Total	-78,477.14	0
1	2014	117		NASIA	4470181	78,477.14	0
					4470181 Total	78,477.14	0
1	2014	117		BUCK	4470206	0.00	0
1	2014	117		PJM	4470206	145,998.32	0
1	2014	117		PJM	4470206	-38.61	0
1	2014	117		PJM	4470206	-553.36	0
1	2014	117		PJM	4470206	-110.06	0
1	2014	117		PJM	4470206	544,464.11	0
1	2014	117		PJM	4470206	-0.33	0
1	2014	117		PJM	4470206	-152,391.82	0
					4470206 Total	537,368.25	0
1	2014	117		PJM	4470209	-172,946.09	0
1	2014	117		PJM	4470209	3,077.27	0
1	2014	117		PJM	4470209	45.93	0

1	2014	117		PJM	4470209	-9,143.55	0
1	2014	117		PJM	4470209	-3,553,876.11	0
1	2014	117		PJM	4470209	48,420.58	0
					4470209 Total	-3,684,421.97	0
1	2014	117		PJM	4470214	41.38	0
1	2014	117		PJM	4470214	4.44	0
1	2014	117		PJM	4470214	1.99	0
1	2014	117		PJM	4470214	28,123.18	0
1	2014	117		PJM	4470214	1.90	0
					4470214 Total	28,172.89	0
1	2014	117		PJM	4470220	5,535.92	0
1	2014	117		PJM	4470220	66.69	0
1	2014	117		PJM	4470220	0.00	0
1	2014	117		PJM	4470220	87,921.67	0
					4470220 Total	93,524.28	0
1	2014	117		PJM	4470221	0.10	0
1	2014	117		PJM	4470221	0.02	0
1	2014	117		PJM	4470221	-0.32	0
1	2014	117		PJM	4470221	6.37	0
1	2014	117		PJM	4470221	-0.10	0
1	2014	117		PJM	4470221	0.75	0
					4470221 Total	6.82	0
1	2014	117		PJM	4470222	338.80	0
					4470222 Total	338.80	0
1	2014	117		PJM	5550039	-2,222.66	0
1	2014	117		PJM	5550039	-1.48	0
1	2014	117		PJM	5550039	-558.58	0
					5550039 Total	-2,782.72	0
1	2014	117		BPEC	5550099	-3,959.15	0
1	2014	117		DBET	5550099	6,652.36	0
1	2014	117		EXGN	5550099	430.70	0
1	2014	117		NASIA	5550099	3,743.73	0
1	2014	117		PJM	5550099	-3,682.16	0
1	2014	117		PJM	5550099	16.07	0
1	2014	117		PJM	5550099	175.60	0
1	2014	117		PJM	5550099	-37,404.64	-350,295
1	2014	117		PJM	5550099	-0.46	0
1	2014	117		PJM	5550099	-0.12	0
1	2014	117		PJM	5550099	-687,118.16	-6,506,013
1	2014	117		PJM	5550099	45.39	0
1	2014	117		PJM	5550099	30.62	0
1	2014	117		UBSF2	5550099	-17.60	0
1	2014	117	HPJM	BPEC	5550099	3,958.75	0
1	2014	117	HPJM	DBET	5550099	179,071.45	0
1	2014	117	HPJM	EXGN	5550099	23,284.57	0
1	2014	117	HPJM	MSUI2	5550099	0.00	0
1	2014	117	HPJM	UBSF2	5550099	11,224.06	0
					5550099 Total	-503,548.99	-6,856,308
1	2014	117		AMEM	5550100	0.00	0
1	2014	117		CMS	5550100	0.00	0
1	2014	117		DYPM	5550100	0.00	0
1	2014	117		EDFT2	5550100	0.00	0
1	2014	117		JPMV2	5550100	0.00	0
1	2014	117	NMSO	AMEM	5550100	-118.88	0
1	2014	117	NMSO	CMS	5550100	-2,234.03	0
1	2014	117	NMSO	DYPM	5550100	-245.05	0
1	2014	117	NMSO	EDFT2	5550100	-496.58	0
1	2014	117	NMSO	JPMV2	5550100	-4,034.57	0
					5550100 Total	-7,129.11	0
1	2014	117		PJM	5550107	-6,875.40	0
1	2014	117		PJM	5550107	-973.50	0
1	2014	117		PJM	5550107	-169.50	0
1	2014	117		PJM	5550107	-1,188.00	0
					5550107 Total	-9,206.40	0
1	2014	110		APBE2	5570007	-12.54	-13

1	2014	110		EKPM	5570007	-1,222.65	0
1	2014	110		POLM2	5570007	-5.76	0
					5570007 Total	-1,240.95	-13
1	2014	117		PJM	5614000	0.00	0
1	2014	117		PJM	5614000	-207.03	0
1	2014	117		PJM	5614000	-28.17	0
1	2014	117		PJM	5614000	-246.54	0
1	2014	117		PJM	5614000	-43,927.44	0
1	2014	117		PJM	5614000	-2.07	0
1	2014	117		PJM	5614000	-6,189.13	0
					5614000 Total	-50,600.38	0
1	2014	117		PJM	5618000	0.00	0
1	2014	117		PJM	5618000	-15.24	0
1	2014	117		PJM	5618000	-31.19	0
1	2014	117		PJM	5618000	-17.95	0
1	2014	117		PJM	5618000	-11,787.27	0
1	2014	117		PJM	5618000	-0.01	0
1	2014	117		PJM	5618000	-7,241.06	0
					5618000 Total	-19,092.72	0
1	2014	117		PJM	5757000	-1,517.98	0
1	2014	117		PJM	5757000	-232.73	0
1	2014	117		PJM	5757000	-11.93	0
1	2014	117		PJM	5757000	-272.15	0
1	2014	117		PJM	5757000	-45,984.45	0
1	2014	117		PJM	5757000	-0.84	0
1	2014	117		PJM	5757000	-3,340.50	0
					5757000 Total	-51,360.58	0
January Total						**42,902,340.71**	**551,393,053**
2	2014	117	OPC Var	OPCVR	4470002	-203,117.72	0
					4470002 Total	-203,117.72	0
2	2014	117		DEOI2	4470006	-407.44	0
2	2014	117		DTET	4470006	911.00	0
2	2014	117		MISO	4470006	-24,069.70	0
2	2014	117		PJM	4470006	30,816.09	943,052
2	2014	117		PJM	4470006	16,596.74	0
2	2014	117		WR	4470006	-97.50	0
2	2014	117	PBAS	BANG2	4470006	10,894.11	174,000
2	2014	117	PBAS	BARR2	4470006	25,928.56	449,000
2	2014	117	PBAS	BLOO2	4470006	19,245.83	316,000
2	2014	117	PBAS	BMES	4470006	10,738.38	173,000
2	2014	117	PBAS	CADO2	4470006	5,197.07	89,000
2	2014	117	PBAS	CECA2	4470006	129,641.53	3,310,560
2	2014	117	PBAS	CORN2	4470006	4,834.56	83,000
2	2014	117	PBAS	CRIU2	4470006	662.46	0
2	2014	117	PBAS	HAME2	4470006	2,356.09	36,000
2	2014	117	PBAS	MEDF2	4470006	30,044.47	533,000
2	2014	117	PBAS	RICE2	4470006	56,338.11	930,000
2	2014	117	PBAS	RPLY	4470006	6,723.99	108,000
2	2014	117	PBAS	SPOO2	4470006	11,602.78	180,000
2	2014	117	PBAS	TOHI2	4470006	8,609.59	140,000
2	2014	117	PBAS	TREM2	4470006	5,224.59	84,000
2	2014	117	PBAS	WAKE2	4470006	5,265.55	92,000
2	2014	117	PHRD	MISO	4470006	141,257.50	2,983,000
2	2014	117	PMAC	MSUI2	4470006	-18.81	0
2	2014	117	PMRT	MISO	4470006	369.50	0
2	2014	117	PMWE	AMPO	4470006	119,122.06	2,005,422
2	2014	117	PMWE	BARC2	4470006	12,159.99	252,806
2	2014	117	PMWE	BPPA2	4470006	2,912.09	80,000
2	2014	117	PMWE	CECA2	4470006	102,627.36	2,006,400
2	2014	117	PMWE	COLS2	4470006	259,195.11	4,300,000
2	2014	117	PMWE	EDFT2	4470006	10,193.35	239,163
2	2014	117	PMWE	EKPM	4470006	80,898.05	2,106,720
2	2014	117	PMWE	GLOU2	4470006	3,895.47	37,000

2	2014	117	PMWE	HREA2	4470006	50,169.66	603,000
2	2014	117	PMWE	INGS2	4470006	5,592.94	146,467
2	2014	117	PMWE	MPPA	4470006	20,269.66	300,960
2	2014	117	PMWE	MSUI2	4470006	-371.83	0
2	2014	117	PMWE	NCEM	4470006	185,812.70	4,213,440
2	2014	117	PMWE	RBCC2	4470006	-216.76	0
2	2014	117	PMWE	SHEL	4470006	27,468.94	311,000
2	2014	117	PMWE	UBSF2	4470006	-1.00	0
2	2014	117	PMWE	WPSC	4470006	125,012.76	3,160,080
2	2014	117	PMWE	WSTR2	4470006	222,296.93	2,535,000
2	2014	117	PMWS	EXGN	4470006	39,877.20	1,003,200
2	2014	117	PNEA	MSUI2	4470006	-12.76	0
2	2014	117	PNEA	UBSF2	4470006	0.00	0
2	2014	117	PNEA	WGES	4470006	42,166.00	1,053,360
2	2014	117	PSHD	MSUI2	4470006	-7.91	0
2	2014	117	PSHD	OVPS	4470006	0.00	0
2	2014	117	PSHD	RBCC2	4470006	-747.38	0
2	2014	117	PSHD	TVAM	4470006	2,018.33	29,032
2	2014	117	PSHD	UBSF2	4470006	0.00	0
					4470006 Total	1,808,996.01	35,006,662
2	2014	117		OVPS	4470010	0.00	123,534,298
2	2014	117		PJM	4470010	-17,219.71	-796,363
2	2014	117		PJM	4470010	17.25	0
2	2014	117		PJM	4470010	-316,833.55	-4,296,220
2	2014	117		PJM	4470010	-192,311.92	-2,596,662
2	2014	117		PJM	4470010	1,544.33	0
2	2014	117		PJM	4470010	81.98	0
2	2014	117		PJM	4470010	-27,376.79	-300,604
2	2014	117		PJM	4470010	-1,089,271.25	-27,868,470
2	2014	117		PJM	4470010	-0.29	0
2	2014	117		PJM	4470010	-11,517.57	-162,581
2	2014	117		PJM	4470010	-3,308.90	-38,375
2	2014	117		PJM	4470010	-2,358.77	-33,835
2	2014	117		PJM	4470010	-7,038.50	-100,149
2	2014	117		PJM	4470010	30.23	0
2	2014	117		PJM	4470010	-41,429.28	-595,036
2	2014	117	OVEC	OVPS	4470010	0.00	-123,534,298
2	2014	117	PBAS	ADPR2	4470010	-768.56	0
2	2014	117	PBAS	DPC	4470010	-17.59	0
2	2014	117	PBAS	MISO	4470010	-198,291.73	-3,148,000
2	2014	117	PBAS	TIMB2	4470010	-768.56	0
2	2014	117	PHET	TVAM	4470010	0.00	0
2	2014	117	PHRD	MISO	4470010	-19,695.33	-452,000
2	2014	117	PHRD	TVAM	4470010	-33,888.58	-742,613
2	2014	117	PHRE	TVAM	4470010	0.00	0
2	2014	117	PHRT	TVAM	4470010	-25,017.22	-584,329
2	2014	117	PMAC	MSUI2	4470010	-89.34	0
2	2014	117	PMRT	MISO	4470010	-292,542.07	-3,461,000
2	2014	117	PMWE	MISO	4470010	23.18	0
2	2014	117	PMWE	MSUI2	4470010	-331.25	0
2	2014	117	PMWE	RBCC2	4470010	-216.76	0
2	2014	117	PMWE	UBSF2	4470010	-1.00	0
2	2014	117	PMWS	EXGN	4470010	-41,131.20	-1,003,200
2	2014	117	PNEA	MSUI2	4470010	-12.76	0
2	2014	117	PNEA	UBSF2	4470010	0.00	0
2	2014	117	PSHD	MSUI2	4470010	-21.57	0
2	2014	117	PSHD	RBCC2	4470010	-747.38	0
2	2014	117	PSHD	TVAM	4470010	-28,541.89	-420,383
2	2014	117	PSHD	UBSF2	4470010	0.00	0
					4470010 Total	-2,349,052.35	-46,599,820
2	2014	117		BUCK	4470028	-20.77	0
2	2014	117		PJM	4470028	0.00	0
2	2014	117	OPC Var	OPCVR	4470028	203,117.72	0
					4470028 Total	203,096.95	0
2	2014	117			4470035	78,595.75	634,000

					4470035 Total	78,595.75	634,000
2	2014	117		ENTE	4470066	157.00	0
2	2014	117		TVAM	4470066	-82.89	0
					4470066 Total	74.11	0
2	2014	117		MSUI2	4470081	0.00	0
2	2014	117	KBAS	MSUI2	4470081	1,824.20	0
2	2014	117	KBAS	RBCC2	4470081	163.39	0
2	2014	117	KBAS	UBSF2	4470081	815.41	0
2	2014	117	KCP	MSUI2	4470081	43.73	0
2	2014	117	KEP	MSUI2	4470081	0.00	0
					4470081 Total	2,846.73	0
2	2014	117		MSUI2	4470082	0.00	0
2	2014	117		NASIA	4470082	-4,973.39	0
2	2014	117		UBSF2	4470082	0.00	0
2	2014	117	HPJM	MSUI2	4470082	0.00	0
2	2014	117	HSHS	MSUI2	4470082	-7,329.39	0
2	2014	117	HSHS	UBSF2	4470082	-699.66	0
2	2014	117	PBAS	AMEM	4470082	1,032.72	0
2	2014	117	PBAS	ARON	4470082	-14,005.54	0
2	2014	117	PBAS	BARC2	4470082	651.60	0
2	2014	117	PBAS	CONC	4470082	-59,694.17	0
2	2014	117	PBAS	DBET	4470082	-8,166.71	0
2	2014	117	PBAS	EDFT2	4470082	-3,152.68	0
2	2014	117	PBAS	EPLU	4470082	-28,562.85	0
2	2014	117	PBAS	EXGN	4470082	153,623.25	0
2	2014	117	PBAS	MECB	4470082	-2,675.81	0
2	2014	117	PBAS	MSCG	4470082	89,388.15	0
2	2014	117	PBAS	MSUI2	4470082	37,237.86	0
2	2014	117	PBAS	NEXT2	4470082	24,394.63	0
2	2014	117	PBAS	RBCC2	4470082	1,997.19	0
2	2014	117	PBAS	SES	4470082	-23,957.03	0
2	2014	117	PBAS	UBSF2	4470082	51,146.24	0
2	2014	117	PHET	MSUI2	4470082	0.00	0
2	2014	117	PHET	UBSF2	4470082	0.00	0
2	2014	117	PHRD	MSUI2	4470082	0.00	0
2	2014	117	PHRE	MSUI2	4470082	0.00	0
2	2014	117	PHRE	UBSF2	4470082	0.00	0
2	2014	117	PHRT	MSUI2	4470082	42,951.45	0
2	2014	117	PHRT	UBSF2	4470082	2.52	0
2	2014	117	PMWE	AMEM	4470082	-46,421.43	0
2	2014	117	PMWE	BARC2	4470082	5,628.21	0
2	2014	117	PMWE	DBET	4470082	72,177.36	0
2	2014	117	PMWE	EPLU	4470082	-12,854.90	0
2	2014	117	PMWE	EXGN	4470082	129,470.73	0
2	2014	117	PMWE	IESI2	4470082	-1,858.75	0
2	2014	117	PMWE	INGS2	4470082	-1,268.82	0
2	2014	117	PMWE	JPMV2	4470082	65,542.47	0
2	2014	117	PMWE	MECB	4470082	-10,401.71	0
2	2014	117	PMWE	MSUI2	4470082	-21,775.24	0
2	2014	117	PMWE	NEXT2	4470082	5,288.06	0
2	2014	117	PMWE	RBCC2	4470082	13,630.18	0
2	2014	117	PMWE	UBSF2	4470082	369,810.51	0
2	2014	117	PNEA	MSUI2	4470082	-30,886.47	0
2	2014	117	PNEA	RBCC2	4470082	-309.01	0
2	2014	117	PNEA	UBSF2	4470082	-7,992.62	0
2	2014	117	PSHD	MSUI2	4470082	-305,358.04	0
2	2014	117	PSHD	RBCC2	4470082	-283.31	0
2	2014	117	PSHD	UBSF2	4470082	-33,959.56	0
					4470082 Total	437,386.04	0
2	2014	117	SPOT MARKE	PJM	4470089	15,893,700.47	0
					4470089 Total	15,893,700.47	0
2	2014	117		PJM	4470098	0.00	0
2	2014	117		PJM	4470098	-214,312.75	0
					4470098 Total	-214,312.75	0
2	2014	117		PJM	4470099	34,137.22	0

2	2014	117	NRMG	NRG	4470099	1,643.24	0
2	2014	117	NRMG	VAPG	4470099	417.83	0
					4470099 Total	36,198.29	0
2	2014	117		PJM	4470100	-6,450.91	0
					4470100 Total	-6,450.91	0
2	2014	117	SPOT MARKE	PJM	4470103	15,424,803.08	490,467,777
					4470103 Total	15,424,803.08	490,467,777
2	2014	117		PJM	4470106	-12.06	0
					4470106 Total	-12.06	0
2	2014	117		PJM	4470107	5,979.22	0
2	2014	117		PJM	4470107	-1,534.34	0
					4470107 Total	4,444.88	0
2	2014	117		PJM	4470109	142,675.99	0
					4470109 Total	142,675.99	0
2	2014	117		PJM	4470110	-0.04	0
					4470110 Total	-0.04	0
2	2014	117		PJM	4470115	0.00	0
2	2014	117		PJM	4470115	-15.41	0
2	2014	117		PJM	4470115	0.00	0
					4470115 Total	-15.41	0
2	2014	117		PJM	4470124	0.00	0
					4470124 Total	0.00	0
2	2014	117		PJM	4470126	0.00	0
2	2014	117		PJM	4470126	-2,844,810.97	0
					4470126 Total	-2,844,810.97	0
2	2014	117		PJM	4470131	0.00	0
					4470131 Total	0.00	0
2	2014	117	HRMG	MSUI2	4470143	0.00	0
2	2014	117	HRMG	UBSF2	4470143	0.00	0
2	2014	117	HSHS	MSUI2	4470143	-48.18	0
2	2014	117	HSHS	UBSF2	4470143	-3,195.17	0
					4470143 Total	-3,243.35	0
2	2014	117	NPJM	DEOI2	4470170	12,803.15	258,000
2	2014	117	NPJM	FESC	4470170	273,797.50	5,387,000
					4470170 Total	286,600.65	5,645,000
2	2014	117		NASIA	4470175	40,576.67	0
					4470175 Total	40,576.67	0
2	2014	117		NASIA	4470176	-40,576.67	0
					4470176 Total	-40,576.67	0
2	2014	117		NASIA	4470180	-47,418.54	0
					4470180 Total	-47,418.54	0
2	2014	117		NASIA	4470181	47,418.54	0
					4470181 Total	47,418.54	0
2	2014	117		PJM	4470206	-298.21	0
2	2014	117		PJM	4470206	219,418.01	0
					4470206 Total	219,119.80	0
2	2014	117		PJM	4470209	0.00	0
2	2014	117		PJM	4470209	-1,967,181.50	0
					4470209 Total	-1,967,181.50	0
2	2014	117		PJM	4470214	0.00	0
2	2014	117		PJM	4470214	0.04	0
					4470214 Total	0.04	0
2	2014	117		PJM	4470220	0.00	0
2	2014	117		PJM	4470220	2,663.57	0
					4470220 Total	2,663.57	0
2	2014	117		PJM	4470221	5,234.21	0
2	2014	117		PJM	4470221	959.96	0
					4470221 Total	6,194.17	0
2	2014	117		PJM	4470222	104,380.48	0
					4470222 Total	104,380.48	0
2	2014	117		PJM	5550039	55,259.76	0
2	2014	117		PJM	5550039	14,504.98	0
					5550039 Total	69,764.74	0
2	2014	117		NASIA	5550099	4,973.39	0
2	2014	117		PJM	5550099	-3,512.28	0

2	2014	117		PJM	5550099	17.25	0
2	2014	117		PJM	5550099	25.52	0
2	2014	117		PJM	5550099	-18,757.15	-291,419
2	2014	117		PJM	5550099	21.76	0
2	2014	117		PJM	5550099	18.21	0
2	2014	117		PJM	5550099	-405,092.33	-5,805,124
2	2014	117		PJM	5550099	41.09	0
2	2014	117		PJM	5550099	29.78	0
2	2014	117	HPJM	DBET	5550099	86,865.05	0
2	2014	117	HPJM	EXGN	5550099	13,157.63	0
2	2014	117	HPJM	MSUI2	5550099	0.00	0
2	2014	117	HPJM	UBSF2	5550099	5,802.46	0
					5550099 Total	-316,409.62	-6,096,543
2	2014	117	NMSO	AMEM	5550100	-118.88	0
2	2014	117	NMSO	CMS	5550100	-2,234.03	0
2	2014	117	NMSO	DYPM	5550100	-245.05	0
2	2014	117	NMSO	EDFT2	5550100	-496.58	0
2	2014	117	NMSO	JPMV2	5550100	-4,034.57	0
					5550100 Total	-7,129.11	0
2	2014	117		PJM	5550107	-6,646.22	0
2	2014	117		PJM	5550107	-941.05	0
2	2014	117		PJM	5550107	-148.77	0
2	2014	117		PJM	5550107	-1,148.40	0
					5550107 Total	-8,884.44	0
2	2014	110		APX	5570007	-125.40	0
2	2014	110		DTET	5570007	-287.79	-2
					5570007 Total	-413.19	-2
2	2014	117		PJM	5614000	0.00	0
2	2014	117		PJM	5614000	-45,294.20	0
					5614000 Total	-45,294.20	0
2	2014	180		PJM	5614008	0.00	0
					5614008 Total	0.00	0
2	2014	117		PJM	5618000	0.00	0
2	2014	117		PJM	5618000	-11,836.54	0
					5618000 Total	-11,836.54	0
2	2014	117		PJM	5757000	0.00	0
2	2014	117		PJM	5757000	-58,225.06	0
					5757000 Total	-58,225.06	0
February Total						**26,685,152.53**	**479,057,074**
3	2014	117		DEOI2	4470006	-394.72	0
3	2014	117		MISO	4470006	-26,412.87	0
3	2014	117		PJM	4470006	35,971.51	1,669,983
3	2014	117		PJM	4470006	-14,870.55	0
3	2014	117	PBAS	BANG2	4470006	9,927.62	162,000
3	2014	117	PBAS	BARR2	4470006	28,287.38	463,000
3	2014	117	PBAS	BLOO2	4470006	19,399.68	320,000
3	2014	117	PBAS	BMES	4470006	8,555.45	190,000
3	2014	117	PBAS	CADO2	4470006	5,475.98	89,000
3	2014	117	PBAS	CECA2	4470006	0.00	0
3	2014	117	PBAS	CORN2	4470006	5,745.65	94,000
3	2014	117	PBAS	CRIU2	4470006	0.00	0
3	2014	117	PBAS	HAME2	4470006	2,061.26	43,000
3	2014	117	PBAS	MEDF2	4470006	43,230.51	721,000
3	2014	117	PBAS	RICE2	4470006	57,415.58	934,000
3	2014	117	PBAS	RPLY	4470006	5,259.91	116,000
3	2014	117	PBAS	SPOO2	4470006	11,412.57	183,000
3	2014	117	PBAS	TOHI2	4470006	8,673.69	138,000
3	2014	117	PBAS	TREM2	4470006	5,438.97	90,000
3	2014	117	PBAS	WAKE2	4470006	5,672.19	95,000
3	2014	117	PHRD	MISO	4470006	128,502.26	2,699,000
3	2014	117	PMAC	MSUI2	4470006	-1,024.40	0
3	2014	117	PMAC	WR	4470006	-0.50	0
3	2014	117	PMWE	AMPO	4470006	80,763.92	1,359,662

Kentucky Power Company
Sales to Electric Utilities
Billing Summary

3	2014	117	PMWE	BARC2	4470006	13,444.75	279,517
3	2014	117	PMWE	BPPA2	4470006	6,212.57	134,000
3	2014	117	PMWE	CECA2	4470006	97,857.14	2,106,720
3	2014	117	PMWE	COLS2	4470006	303,621.81	4,475,000
3	2014	117	PMWE	EDFT2	4470006	10,894.01	253,521
3	2014	117	PMWE	EKPM	4470006	89,445.31	2,329,305
3	2014	117	PMWE	GLOU2	4470006	1,797.07	35,000
3	2014	117	PMWE	HREA2	4470006	45,320.88	569,000
3	2014	117	PMWE	INGS2	4470006	3,417.74	88,721
3	2014	117	PMWE	MPPA	4470006	21,283.14	316,008
3	2014	117	PMWE	MSUI2	4470006	-9.14	0
3	2014	117	PMWE	NCEM	4470006	205,444.70	4,658,610
3	2014	117	PMWE	RBCC2	4470006	-47.67	0
3	2014	117	PMWE	SHEL	4470006	18,851.32	267,000
3	2014	117	PMWE	UBSF2	4470006	0.00	0
3	2014	117	PMWE	WPSC	4470006	138,406.99	3,498,660
3	2014	117	PMWE	WSTR2	4470006	172,903.75	2,558,000
3	2014	117	PMWS	EXGN	4470006	-5.77	0
3	2014	117	PNEA	DEL	4470006	-612.44	0
3	2014	117	PNEA	MSUI2	4470006	0.00	0
3	2014	117	PNEA	WGES	4470006	0.00	0
3	2014	117	PSHD	MSUI2	4470006	0.00	0
3	2014	117	PSHD	RBCC2	4470006	690.21	0
3	2014	117	PSHD	TVAM	4470006	-2,018.33	-29,032
					4470006 Total	1,545,989.13	30,906,675
3	2014	117		PJM	4470010	13,050.05	123,589
3	2014	117		PJM	4470010	5.68	0
3	2014	117		PJM	4470010	-16.17	0
3	2014	117		PJM	4470010	-303,752.29	-4,464,853
3	2014	117		PJM	4470010	-176,362.30	-2,521,753
3	2014	117		PJM	4470010	0.05	0
3	2014	117		PJM	4470010	0.65	0
3	2014	117		PJM	4470010	2,052.66	0
3	2014	117		PJM	4470010	13.61	0
3	2014	117		PJM	4470010	0.12	0
3	2014	117		PJM	4470010	-23,490.89	-268,071
3	2014	117		PJM	4470010	-230,786.43	-11,127,758
3	2014	117		PJM	4470010	0.69	0
3	2014	117		PJM	4470010	-10,804.67	-154,546
3	2014	117		PJM	4470010	-2,588.92	-33,079
3	2014	117		PJM	4470010	-2,293.08	-32,390
3	2014	117		PJM	4470010	-6,742.95	-98,294
3	2014	117		PJM	4470010	-35,255.70	-562,942
3	2014	117	OVEC	OVPS	4470010	0.00	0
3	2014	117	PBAS	DPC	4470010	-17.59	0
3	2014	117	PBAS	MISO	4470010	-163,389.95	-3,185,000
3	2014	117	PHRD	MISO	4470010	-10,287.28	-242,000
3	2014	117	PHRD	TVAM	4470010	-36,903.62	-932,626
3	2014	117	PHRT	TVAM	4470010	0.00	0
3	2014	117	PMAC	MSUI2	4470010	-1,047.91	0
3	2014	117	PMAC	SWE	4470010	-0.25	0
3	2014	117	PMRT	MISO	4470010	-271,455.90	-3,815,000
3	2014	117	PMWE	MISO	4470010	-77.20	0
3	2014	117	PMWE	MSUI2	4470010	-22.69	0
3	2014	117	PMWE	RBCC2	4470010	-44.78	0
3	2014	117	PMWE	UBSF2	4470010	0.00	0
3	2014	117	PMWS	EXGN	4470010	0.00	0
3	2014	117	PMWS	MSCG	4470010	-5.52	0
3	2014	117	PNEA	MSUI2	4470010	0.00	0
3	2014	117	PSHD	MSUI2	4470010	0.00	0
3	2014	117	PSHD	PJM	4470010	62,935.58	-123,589
3	2014	117	PSHD	RBCC2	4470010	690.21	0
3	2014	117	PSHD	TVAM	4470010	-101,453.82	-2,857,380
					4470010 Total	-1,298,050.61	-30,295,692
3	2014	117			4470035	-2.00	0

					4470035 Total	-2.00	0
3	2014	117	KBAS	MSUI2	4470081	-1,001.86	0
3	2014	117	KBAS	RBCC2	4470081	2,221.62	0
3	2014	117	KCP	MSUI2	4470081	1,533.01	0
					4470081 Total	2,752.77	0
3	2014	117			4470082	-0.16	0
3	2014	117		NASIA	4470082	-10,112.30	0
3	2014	117	HSHS	MSUI2	4470082	7,329.39	0
3	2014	117	HSHS	UBSF2	4470082	699.66	0
3	2014	117	PBAS	AMEM	4470082	498.76	0
3	2014	117	PBAS	ARON	4470082	-14,433.30	0
3	2014	117	PBAS	BARC2	4470082	1,076.19	0
3	2014	117	PBAS	CONC	4470082	-67,323.42	0
3	2014	117	PBAS	DBET	4470082	-4,183.17	0
3	2014	117	PBAS	EDFT2	4470082	-3,487.67	0
3	2014	117	PBAS	EPLU	4470082	-29,504.51	0
3	2014	117	PBAS	EXGN	4470082	128,844.52	0
3	2014	117	PBAS	MECB	4470082	-2,626.48	0
3	2014	117	PBAS	MSCG	4470082	55,440.95	0
3	2014	117	PBAS	MSUI2	4470082	52,963.80	0
3	2014	117	PBAS	NEXT2	4470082	35,153.54	0
3	2014	117	PBAS	RBCC2	4470082	117,932.18	0
3	2014	117	PBAS	SES	4470082	-17,201.62	0
3	2014	117	PBAS	UBSF2	4470082	2,848.66	0
3	2014	117	PHET	MSUI2	4470082	0.00	0
3	2014	117	PHET	RBCC2	4470082	0.00	0
3	2014	117	PHET	UBSF2	4470082	0.00	0
3	2014	117	PHRD	UBSF2	4470082	1,670.33	0
3	2014	117	PHRE	MSUI2	4470082	0.00	0
3	2014	117	PHRE	RBCC2	4470082	0.00	0
3	2014	117	PHRE	UBSF2	4470082	0.00	0
3	2014	117	PHRT	MSUI2	4470082	-51,316.50	0
3	2014	117	PHRT	RBCC2	4470082	0.00	0
3	2014	117	PHRT	UBSF2	4470082	3,279.69	0
3	2014	117	PMWE	AMEM	4470082	-28,209.36	0
3	2014	117	PMWE	BARC2	4470082	7,294.49	0
3	2014	117	PMWE	DBET	4470082	45,853.81	0
3	2014	117	PMWE	EPLU	4470082	-12,526.34	0
3	2014	117	PMWE	EXGN	4470082	103,050.24	0
3	2014	117	PMWE	IESI2	4470082	-1,249.27	0
3	2014	117	PMWE	INGS2	4470082	0.01	0
3	2014	117	PMWE	JPMV2	4470082	68,341.60	0
3	2014	117	PMWE	MECB	4470082	-7,185.72	0
3	2014	117	PMWE	MSUI2	4470082	-79,339.78	0
3	2014	117	PMWE	NEXT2	4470082	6,394.19	0
3	2014	117	PMWE	RBCC2	4470082	120,257.47	0
3	2014	117	PMWE	UBSF2	4470082	-13,812.00	0
3	2014	117	PNEA	MSUI2	4470082	-58,307.52	0
3	2014	117	PNEA	RBCC2	4470082	-3,928.70	0
3	2014	117	PNEA	UBSF2	4470082	11.98	0
3	2014	117	PSHD	MSUI2	4470082	418,269.87	0
3	2014	117	PSHD	RBCC2	4470082	-57,507.09	0
3	2014	117	PSHD	UBSF2	4470082	3,011.35	0
					4470082 Total	717,967.77	0
3	2014	117	SPOT MARKE	PJM	4470089	12,505,524.06	0
					4470089 Total	12,505,524.06	0
3	2014	117		PJM	4470098	-558,935.26	0
3	2014	117		PJM	4470098	-96,097.85	0
					4470098 Total	-655,033.11	0
3	2014	117		PJM	4470099	37,867.48	0
3	2014	117	NRMG	NRG	4470099	1,819.30	0
3	2014	117	NRMG	VAPG	4470099	462.60	0
					4470099 Total	40,149.38	0
3	2014	117		PJM	4470100	567,778.22	0
					4470100 Total	567,778.22	0

3	2014	117	SPOT MARKE	PJM	4470103	12,365,613.12	435,870,693
					4470103 Total	12,365,613.12	435,870,693
3	2014	117		PJM	4470107	21,743.28	0
3	2014	117		PJM	4470107	-2,074.62	0
					4470107 Total	19,668.66	0
3	2014	117		PJM	4470109	-11,407.85	0
					4470109 Total	-11,407.85	0
3	2014	117		PJM	4470110	34,639.54	0
					4470110 Total	34,639.54	0
3	2014	117		PJM	4470115	0.00	0
3	2014	117		PJM	4470115	112.78	0
					4470115 Total	112.78	0
3	2014	117		PJM	4470124	0.25	0
					4470124 Total	0.25	0
3	2014	117		PJM	4470126	0.00	0
3	2014	117		PJM	4470126	-2,796,461.60	0
					4470126 Total	-2,796,461.60	0
3	2014	117	HSHS	MSUI2	4470143	-207,942.48	0
3	2014	117	HSHS	RBCC2	4470143	0.00	0
3	2014	117	HSHS	UBSF2	4470143	-10,287.37	0
					4470143 Total	-218,229.85	0
3	2014	117		UBS	4470168	-3,285.02	0
					4470168 Total	-3,285.02	0
3	2014	117	NPJM	DEOI2	4470170	13,200.70	266,000
3	2014	117	NPJM	FESC	4470170	287,058.91	5,648,000
					4470170 Total	300,259.61	5,914,000
3	2014	117		NASIA	4470175	38,479.88	0
					4470175 Total	38,479.88	0
3	2014	117		NASIA	4470176	-38,479.88	0
					4470176 Total	-38,479.88	0
3	2014	117		NASIA	4470180	-28,758.83	0
					4470180 Total	-28,758.83	0
3	2014	117		NASIA	4470181	28,758.83	0
					4470181 Total	28,758.83	0
3	2014	117		PJM	4470206	188,764.98	0
					4470206 Total	188,764.98	0
3	2014	117		PJM	4470209	0.00	0
3	2014	117		PJM	4470209	-1,240,718.48	0
					4470209 Total	-1,240,718.48	0
3	2014	117		PJM	4470214	7.11	0
					4470214 Total	7.11	0
3	2014	117		PJM	4470221	1,380.77	0
					4470221 Total	1,380.77	0
3	2014	117		PJM	4470222	53,575.43	0
					4470222 Total	53,575.43	0
3	2014	117		PJM	5550039	-6,126.24	0
3	2014	117		PJM	5550039	11,348.70	0
					5550039 Total	5,222.46	0
3	2014	117		NASIA	5550099	10,112.30	0
3	2014	117		PJM	5550099	23,919.20	0
3	2014	117		PJM	5550099	5.68	0
3	2014	117		PJM	5550099	-19.43	0
3	2014	117		PJM	5550099	194.46	0
3	2014	117		PJM	5550099	-16,401.60	-250,038
3	2014	117		PJM	5550099	-29.82	0
3	2014	117		PJM	5550099	23.08	0
3	2014	117		PJM	5550099	5.35	0
3	2014	117		PJM	5550099	-390,962.43	-5,973,986
3	2014	117		PJM	5550099	42.08	0
3	2014	117		PJM	5550099	30.73	0
3	2014	117		PJM	5550099	2.99	0
3	2014	117		PJM	5550099	3.30	0
3	2014	117	HPJM	DBET	5550099	91,281.76	0
3	2014	117	HPJM	EXGN	5550099	8,428.29	0
3	2014	117	HPJM	MSUI2	5550099	0.00	0

3	2014	117	HPJM	RBCC2	5550099	8,837.72	0
3	2014	117	HPJM	UBSF2	5550099	914.45	0
					5550099 Total	-263,611.89	-6,224,024
3	2014	117	NMSO	AMEM	5550100	-118.88	0
3	2014	117	NMSO	CMS	5550100	-2,234.03	0
3	2014	117	NMSO	DYPM	5550100	-245.05	0
3	2014	117	NMSO	EDFT2	5550100	-496.58	0
3	2014	117	NMSO	JPMV2	5550100	-4,034.57	0
					5550100 Total	-7,129.11	0
3	2014	117		PJM	5550107	-7,104.58	0
3	2014	117		PJM	5550107	-1,005.95	0
3	2014	117		PJM	5550107	-159.03	0
3	2014	117		PJM	5550107	-1,227.60	0
					5550107 Total	-9,497.16	0
3	2014	110		EVOL2	5570007	-13.25	-1,325
3	2014	110		WPPI	5570007	-8,983.25	-1,922
					5570007 Total	-8,996.50	-3,247
3	2014	117		PJM	5614000	0.00	0
3	2014	117		PJM	5614000	-26,234.88	0
					5614000 Total	-26,234.88	0
3	2014	180		PJM	5614008	0.00	0
					5614008 Total	0.00	0
3	2014	117		PJM	5618000	0.00	0
3	2014	117		PJM	5618000	-5,693.50	0
					5618000 Total	-5,693.50	0
3	2014	117		PJM	5757000	0.00	0
3	2014	117		PJM	5757000	-33,021.39	0
					5757000 Total	-33,021.39	0
March Total						**21,772,033.09**	**436,168,405**
4	2014	117		NASIA	4470001	0.00	0
					4470001 Total	0.00	0
4	2014	117		NASIA	4470002	0.00	0
					4470002 Total	0.00	0
4	2014	117		DEOI2	4470006	-260.46	0
4	2014	117		MISO	4470006	-26,051.65	0
4	2014	117		NASIA	4470006	0.00	0
4	2014	117		PJM	4470006	-23,026.91	-1,301,462
4	2014	117		PJM	4470006	92,258.13	0
4	2014	117	PBAS	BANG2	4470006	8,428.77	138,000
4	2014	117	PBAS	BARR2	4470006	25,546.47	417,000
4	2014	117	PBAS	BLOO2	4470006	16,850.45	271,000
4	2014	117	PBAS	BMES	4470006	8,759.23	134,000
4	2014	117	PBAS	CADO2	4470006	4,418.09	69,000
4	2014	117	PBAS	CORN2	4470006	4,015.95	63,000
4	2014	117	PBAS	HAME2	4470006	2,028.12	29,000
4	2014	117	PBAS	MEDF2	4470006	40,078.14	691,000
4	2014	117	PBAS	RICE2	4470006	50,641.47	810,000
4	2014	117	PBAS	RPLY	4470006	5,647.56	89,000
4	2014	117	PBAS	SPOO2	4470006	10,508.40	159,000
4	2014	117	PBAS	TOHI2	4470006	6,114.95	96,000
4	2014	117	PBAS	TREM2	4470006	4,360.96	67,000
4	2014	117	PBAS	WAKE2	4470006	4,316.34	70,000
4	2014	117	PHRD	MISO	4470006	95,387.62	2,238,000
4	2014	117	PMAC	EDFT2	4470006	3,176.64	100,320
4	2014	117	PMAC	EXGN	4470006	26,239.70	652,080
4	2014	117	PMAC	JPMV2	4470006	7,923.28	200,640
4	2014	117	PMAC	MSCG	4470006	2,005.90	50,160
4	2014	117	PMAC	MSUI2	4470006	-0.13	0
4	2014	117	PMAC	WR	4470006	3,661.18	100,320
4	2014	117	PMRT	MISO	4470006	24,962.94	0
4	2014	117	PMWE	AMPO	4470006	46,266.49	778,897
4	2014	117	PMWE	BARC2	4470006	13,028.56	270,864
4	2014	117	PMWE	BPPA2	4470006	1,410.97	52,000

4	2014	117	PMWE	CECA2	4470006	0.00	0
4	2014	117	PMWE	COLS2	4470006	264,511.71	4,138,000
4	2014	117	PMWE	EDFT2	4470006	10,441.22	226,398
4	2014	117	PMWE	EKPM	4470006	86,676.48	2,257,200
4	2014	117	PMWE	GLOU2	4470006	2,423.08	21,000
4	2014	117	PMWE	HREA2	4470006	21,459.26	418,000
4	2014	117	PMWE	INGS2	4470006	0.00	0
4	2014	117	PMWE	MPPA	4470006	22,296.62	331,056
4	2014	117	PMWE	MSUI2	4470006	0.00	0
4	2014	117	PMWE	NCEM	4470006	199,085.04	4,514,400
4	2014	117	PMWE	RBCC2	4470006	-91.55	0
4	2014	117	PMWE	SHEL	4470006	21,447.94	196,000
4	2014	117	PMWE	WPSC	4470006	133,942.25	3,385,800
4	2014	117	PMWE	WSTR2	4470006	187,931.27	2,163,000
4	2014	117	PMWS	EXGN	4470006	38,931.43	1,153,680
4	2014	117	PMWS	MSCG	4470006	-10.78	0
4	2014	117	PNEA	RBCC2	4470006	-25.58	0
4	2014	117	PSHD	MSUI2	4470006	-5.22	0
4	2014	117	PSHD	RBCC2	4470006	-54.83	0
					4470006 Total	1,447,655.50	25,049,353
4	2014	117		PJM	4470010	8,573.53	0
4	2014	117		PJM	4470010	23.55	0
4	2014	117		PJM	4470010	52.19	0
4	2014	117		PJM	4470010	7.94	0
4	2014	117		PJM	4470010	-221,128.97	-4,151,083
4	2014	117		PJM	4470010	-118,209.21	-2,167,000
4	2014	117		PJM	4470010	18.72	0
4	2014	117		PJM	4470010	0.06	0
4	2014	117		PJM	4470010	716.80	0
4	2014	117		PJM	4470010	54.65	0
4	2014	117		PJM	4470010	4.47	0
4	2014	117		PJM	4470010	-15,923.44	-177,060
4	2014	117		PJM	4470010	-327,088.58	-8,125,018
4	2014	117		PJM	4470010	0.08	0
4	2014	117		PJM	4470010	-10,406.55	-119,031
4	2014	117		PJM	4470010	-1,661.94	-21,695
4	2014	117		PJM	4470010	-2,438.56	-23,540
4	2014	117		PJM	4470010	-6,126.35	-81,061
4	2014	117		PJM	4470010	12.64	0
4	2014	117		PJM	4470010	-22,428.15	-450,117
4	2014	117	PBAS	DPC	4470010	-4,152.66	0
4	2014	117	PBAS	MISO	4470010	-112,319.70	-2,815,000
4	2014	117	PBAS	WPPI	4470010	-129.79	0
4	2014	117	PHRD	MISO	4470010	-20,167.97	-445,000
4	2014	117	PHRD	TVAM	4470010	-27,798.56	-783,870
4	2014	117	PMAC	EXGN	4470010	-3,242.59	-100,320
4	2014	117	PMAC	MSCG	4470010	-3,662.68	-100,320
4	2014	117	PMAC	MSUI2	4470010	-0.13	0
4	2014	117	PMAC	SWE	4470010	-32,266.92	-953,040
4	2014	117	PMRT	MISO	4470010	-152,380.35	-3,717,000
4	2014	117	PMWE	MISO	4470010	438.22	0
4	2014	117	PMWE	MSUI2	4470010	-9.03	0
4	2014	117	PMWE	RBCC2	4470010	-86.28	0
4	2014	117	PMWS	EXGN	4470010	-5.27	0
4	2014	117	PMWS	MSCG	4470010	-42,761.40	-1,103,520
4	2014	117	PNEA	RBCC2	4470010	-25.58	0
4	2014	117	PSHD	MSUI2	4470010	-19.78	0
4	2014	117	PSHD	PJM	4470010	0.00	0
4	2014	117	PSHD	RBCC2	4470010	-53.21	0
4	2014	117	PSHD	TVAM	4470010	-91,134.18	-2,872,661
					4470010 Total	-1,205,724.98	-28,206,336
4	2014	117		NASIA	4470028	0.00	0
4	2014	117		PJM	4470028	186,577.63	1,804,893
					4470028 Total	186,577.63	1,804,893
4	2014	117			4470035	-87,862.74	-846,069

4	2014	117		NASIA	4470035	0.00	0
					4470035 Total	-87,862.74	-846,069
4	2014	117	KBAS	MSUI2	4470081	1,530.66	0
4	2014	117	KBAS	RBCC2	4470081	1,270.36	0
4	2014	117	KCP	MSUI2	4470081	43.73	0
4	2014	117	KEP	MSUI2	4470081	-12.96	0
					4470081 Total	2,831.79	0
4	2014	117		NASIA	4470082	-8,164.74	0
4	2014	117	PBAS	AMEM	4470082	232.36	0
4	2014	117	PBAS	ARON	4470082	1,131.14	0
4	2014	117	PBAS	BARC2	4470082	-280.70	0
4	2014	117	PBAS	CONC	4470082	1,302.70	0
4	2014	117	PBAS	DBET	4470082	-2,205.21	0
4	2014	117	PBAS	EDFT2	4470082	794.36	0
4	2014	117	PBAS	EPLU	4470082	1,677.83	0
4	2014	117	PBAS	EXGN	4470082	-4,254.06	0
4	2014	117	PBAS	MECB	4470082	-207.00	0
4	2014	117	PBAS	MSCG	4470082	-11,567.58	0
4	2014	117	PBAS	MSUI2	4470082	16,948.12	0
4	2014	117	PBAS	NEXT2	4470082	-1,305.74	0
4	2014	117	PBAS	RBCC2	4470082	-12,613.28	0
4	2014	117	PBAS	SES	4470082	-902.49	0
4	2014	117	PHRT	MSUI2	4470082	-1,998.31	0
4	2014	117	PMWE	AMEM	4470082	242.03	0
4	2014	117	PMWE	BARC2	4470082	-2,505.98	0
4	2014	117	PMWE	DBET	4470082	-4,103.03	0
4	2014	117	PMWE	EPLU	4470082	-488.89	0
4	2014	117	PMWE	EXGN	4470082	-45,694.13	0
4	2014	117	PMWE	IESI2	4470082	-284.55	0
4	2014	117	PMWE	JPMV2	4470082	-20,313.30	0
4	2014	117	PMWE	MECB	4470082	-1,167.85	0
4	2014	117	PMWE	MSUI2	4470082	11,292.42	0
4	2014	117	PMWE	NEXT2	4470082	1,529.83	0
4	2014	117	PMWE	RBCC2	4470082	17,101.88	0
4	2014	117	PNEA	MSUI2	4470082	-2,055.55	0
4	2014	117	PNEA	RBCC2	4470082	-8,251.30	0
4	2014	117	PSHD	MSUI2	4470082	5,824.20	0
4	2014	117	PSHD	RBCC2	4470082	399.92	0
					4470082 Total	-69,886.90	0
4	2014	117		NASIA	4470089	0.00	0
4	2014	117	SPOT MARKE	PJM	4470089	9,435,147.10	0
					4470089 Total	9,435,147.10	0
4	2014	117		NASIA	4470098	0.00	0
4	2014	117		PJM	4470098	570,648.86	0
4	2014	117		PJM	4470098	-798,295.98	0
					4470098 Total	-227,647.12	0
4	2014	117		NASIA	4470099	0.00	0
4	2014	117		PJM	4470099	35,536.50	0
4	2014	117	NRMG	NRG	4470099	1,760.62	0
4	2014	117	NRMG	VAPG	4470099	447.68	0
					4470099 Total	37,744.80	0
4	2014	117		NASIA	4470100	0.00	0
4	2014	117		PJM	4470100	8,958.69	0
					4470100 Total	8,958.69	0
4	2014	117		NASIA	4470103	0.00	0
4	2014	117	SPOT MARKE	PJM	4470103	16,371,827.45	625,523,223
					4470103 Total	16,371,827.45	625,523,223
4	2014	117		PJM	4470107	0.11	0
4	2014	117		PJM	4470107	-1,956.81	0
4	2014	117		PJM	4470107	-204.46	0
					4470107 Total	-2,161.16	0
4	2014	117		PJM	4470109	-2,154.40	0
					4470109 Total	-2,154.40	0
4	2014	117		PJM	4470110	-0.01	0
4	2014	117		PJM	4470110	265.05	0

					4470110 Total	265.04	0
4	2014	117	NRMG	ULHP	4470112	4,943.27	0
					4470112 Total	4,943.27	0
4	2014	117		NASIA	4470115	0.00	0
4	2014	117		PJM	4470115	-2,805.17	0
4	2014	117		PJM	4470115	250.15	0
					4470115 Total	-2,555.02	0
4	2014	117		NASIA	4470124	0.00	0
4	2014	117		PJM	4470124	0.34	0
					4470124 Total	0.34	0
4	2014	117		PJM	4470126	56,533.05	0
4	2014	117		PJM	4470126	-380,530.28	0
					4470126 Total	-323,997.23	0
4	2014	117		NASIA	4470128	0.00	0
					4470128 Total	0.00	0
4	2014	117	HSHS	MSUI2	4470143	-1,467.29	0
4	2014	117	HSHS	RBCC2	4470143	-1,293.23	0
					4470143 Total	-2,760.52	0
4	2014	117		NASIA	4470170	0.00	0
4	2014	117	NPJM	DEOI2	4470170	8,786.64	177,000
4	2014	117	NPJM	FESC	4470170	234,652.13	4,616,000
					4470170 Total	243,438.77	4,793,000
4	2014	117		NASIA	4470173	0.00	0
					4470173 Total	0.00	0
4	2014	117		NASIA	4470174	0.00	0
					4470174 Total	0.00	0
4	2014	117		NASIA	4470175	34,694.51	0
					4470175 Total	34,694.51	0
4	2014	117		NASIA	4470176	-34,694.51	0
					4470176 Total	-34,694.51	0
4	2014	117		NASIA	4470180	5,563.90	0
					4470180 Total	5,563.90	0
4	2014	117		NASIA	4470181	-5,563.90	0
					4470181 Total	-5,563.90	0
4	2014	117		PJM	4470204	-0.04	0
					4470204 Total	-0.04	0
4	2014	117		NASIA	4470206	0.00	0
4	2014	117		PJM	4470206	0.00	0
4	2014	117		PJM	4470206	32,809.44	0
					4470206 Total	32,809.44	0
4	2014	117		NASIA	4470209	0.00	0
4	2014	117		PJM	4470209	-6,262.40	0
4	2014	117		PJM	4470209	-631,494.04	0
					4470209 Total	-637,756.44	0
4	2014	117		PJM	4470214	0.00	0
					4470214 Total	0.00	0
4	2014	117		PJM	4470220	1,236.95	0
					4470220 Total	1,236.95	0
4	2014	117		PJM	4470221	1,391.87	0
					4470221 Total	1,391.87	0
4	2014	117		PJM	4470222	52,700.80	0
					4470222 Total	52,700.80	0
4	2014	117		NASIA	4470228	0.00	0
4	2014	117		PJM	4470228	0.00	0
					4470228 Total	0.00	0
4	2014	117		PJM	5550039	-34.32	0
4	2014	117		PJM	5550039	-1,369.42	0
					5550039 Total	-1,403.74	0
4	2014	117		NASIA	5550099	8,164.74	0
4	2014	117		PJM	5550099	-36,453.77	0
4	2014	117		PJM	5550099	23.55	0
4	2014	117		PJM	5550099	65.68	0
4	2014	117		PJM	5550099	-9,653.40	-185,843
4	2014	117		PJM	5550099	-0.05	0
4	2014	117		PJM	5550099	-0.01	0

4	2014	117		PJM	5550099	-196,906.41	-4,842,825
4	2014	117		PJM	5550099	34.30	0
4	2014	117		PJM	5550099	25.84	0
4	2014	117	HPJM	DBET	5550099	11,628.29	0
4	2014	117	HPJM	EXGN	5550099	344.01	0
4	2014	117	HPJM	RBCC2	5550099	-6,269.70	0
					5550099 Total	-228,996.93	-5,028,668
4	2014	117	NMSO	AMEM	5550100	-118.88	0
4	2014	117	NMSO	CMS	5550100	-2,234.03	0
4	2014	117	NMSO	DYPM	5550100	-245.05	0
4	2014	117	NMSO	EDFT2	5550100	-496.58	0
4	2014	117	NMSO	JPMV2	5550100	-4,034.57	0
					5550100 Total	-7,129.11	0
4	2014	117		PJM	5550107	-6,875.40	0
4	2014	117		PJM	5550107	-973.50	0
4	2014	117		PJM	5550107	-153.90	0
4	2014	117		PJM	5550107	-1,188.00	0
					5550107 Total	-9,190.80	0
4	2014	117		PJM	5614000	-43,528.41	0
					5614000 Total	-43,528.41	0
4	2014	117		PJM	5614008	-2,417.32	0
4	2014	180		PJM	5614008	0.00	0
					5614008 Total	-2,417.32	0
4	2014	117		PJM	5618000	-9,995.98	0
					5618000 Total	-9,995.98	0
4	2014	117		PJM	5757000	-50,069.06	0
					5757000 Total	-50,069.06	0
April Total						**24,912,291.54**	**623,089,395**

Kentucky Power Company
Sales to Electric Utilities
Billing Summary

Tracking Code	Description
ADPR2	Advan Promotions, Inc
AMEM	Ameren Energy Marketing
AMPO	American Muni Power - Ohio
APBE2	ICAP Energy LLC
APN5	American Power Net Management
APX	Automated Power Exchange Inc
ARON	J. Aron Company
BANG2	Village of Bangor, Wisconsin
BARC2	Barclays Bank
BARR2	City of Barron, Wisconsin
BLOO2	City of Bloomer, Wisconsin
BMES	Village of Bethel Ohio
BPEC	BP Energy Company
BPPA2	The Borough of Pitcaim, PA
BUCK	Buckeye Rural Electric
CADO2	Village of Cadott, Wisconsin
CECA2	Commonwealth Edison Company
CEI	Citigroup Energy Inc
CISO	California ISO
CMS	CMS Energy Resource Management Company
COLS2	City of Columbus
CONC	Conoco Inc.
CORN2	City of Cornell, Wisconsin
CRIU2	Crius Energy, LLC
CWEL2	City of Croswell, MI
DBET	DB Energy Trading LLC
DEL	Delmarva Power & Light
DEOI2	Duke Energy Ohio, Inc.
DPC	Dairyland Power Cooperative
DPLG	DP&L Power Services
DTET	DTE Energy Trading Inc.
DYPM	Dynergy Power Marketing Inc.
ECSO2	ECR SO2
EDFT2	EDF Trading North America LLC
EKPM	East Kentucky Power Co-Op Power Marketing
EMAH2	Energy Marketing, a division of America Hess
ENAM	Energy America
ENTE	Entergy Power Services
EPLU	PP&L Energy Plus Co.
EUTL2	Easton Utilities Commission
EVOL2	Evolution Markets Inc.
EXGN	Exelon Generation
FESC	First Energy Trading Services
GLOU2	Village of Glouster

Kentucky Power Company
Sales to Electric Utilities
Billing Summary

HAME2	Village of Hammersville
HREA2	Harrison Rural Electrification
IESI2	Integrys Energy Services Inc.
INGS2	Interstate Gas Supply, Inc.
IPWC2	Interstate Power & Light Company
JPMV2	JP Morgan Ventures Energy Corporation
MECB	MidAmerican Energy
MEDF2	City of Medford
MISO	Midwest ISO
MPPA	Michigan Public Power Agency
MSCG	Morgan Stanley Capt.
MSUI2	Mizuho Securities USA Inc.
NAGP	Noble America's Gas & Power Corp
NASIA	Systems Integration Agreement
NCEM	NC Electric Membership Corp
NEXT2	NextEra Energy Power Marketing, LLC
NRG	NRG Power Marketing, Inc
OPCVR	OPC Variable
OTP	Otter Tail Corporation d.b.a. Otter Tail Power Company
OVPS	Ohio Valley Electric Corporation Power Scheduling
PJM	PJM Interconnection
POLM2	Polaris Markets
PPLT2	PPL Electric Utilities Corporation
RBCC2	RBC Capital Market, LLC
RICE2	City of Rice Lake Utilities
RPLY	Village of Ripley Ohio
SEBE2	Village of Sebewang, MI
SES	Sempra Energy Solutions, LLC
SHEL	City of Shelby
SOLS2	Sol Systems
SOY	Prairie Power
SPOO2	City of Spooner, Wisconsin
SWE	Southern Company
TFS2	TFS Energy
TIMB2	Timber Canyon
TITA2	Titan Energy Markets
TOHI2	Town of Hagerstown Indiana
TREM2	TVA Bulk Power Trading
TVAM	UBS AG Long Branch
UBS	UBS Securities LLC
UBSF2	Union Electric Company
UECO2	Union Electric Company
ULHP	Duke Energy Kentucky, Inc
VAPG	Virginia Power Marketing
WAKE2	City of Wakefield, Michigan
WGES	Washington Gas Energy Services Inc.
WPPI	WPPI Energy
WPSC	Wolverine Power Supply Coop.
WR	Westar Energy Inc
WSTR2	City of Westerville

Kentucky Power Company

REQUEST

List Kentucky Power's scheduled, actual, and forced outages from November 1, 2013, through April 30, 2014.

RESPONSE

Please see Attachment 1 to this response for a listing of outages for the Big Sandy Plant for November 1, 2013 through April 30, 2014 and a listing of outages for the Mitchell Plant for January 1, 2014 through April 30, 2014.

WITNESS: Daniel L. Moyer and Aaron M. Sink

Company Name: Kentucky Power Company
Station Name - Unit Number: Big Sandy Unit No. 1
For the Months of: November 1, 2013 to April 30, 2014

	MAINTENANCE				HOURS OF DURATION			
	Scheduled		Actual 1/					
MONTH	From	To	From	To	Scheduled	Forced	Actual	REASON FOR DEVIATIONS FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE, AS APPROPRIATE
November	1-Nov	22-Nov	1-Nov	22-Nov	514.17		514.17	Planned Outage Repair (Boiler, Precipitator)
April	18-Apr	30-Apr	18-Apr	30-Apr	310.73		310.73	Maintenance Outage Repair (Boiler, Precipitator)

Company Name: Kentucky Power
Station Name - Unit Number: Big Sandy Unit No. 2
For the Months of November 1,2013 to April 30, 2014

	MAINTENANCE				HOURS OF DURATION			
	Scheduled		Actual[1/]					
MONTH	From	To	From	To	Scheduled	Forced	Actual	REASON FOR DEVIATIONS FROM SCHEDULED MAINTANANCE OR REASON FOR FORCED OUTAGE, AS APPROPRIATE
November			1-Nov	30-Nov		714.5	714.5	Turbine Rotor Replacement
December			1-Dec	1-Dec		0.53	0.53	Turbine Overspeed Protection Check
December			18-Dec	23-Dec		122.77	122.77	Boiler Water Chemistry Upset
December	23-Dec	31-Dec	23-Dec	31-Dec	192		192	Maintenance Outage- Boiler Casing Repairs
December	31-Dec	1-Jan	31-Dec	1-Jan	25.27		25.27	Reserve Shutdown
February			25-Feb	12-Mar		367.72	367.72	Boiler Tube Leak
March	12-Mar	14-Mar	12-Mar	14-Mar	56.8		56.8	Maintenance Outage - Boiler Casing Repairs
March	14-Mar	15-Mar	14-Mar	15-Mar	12.3		12.3	Reserve Shutdown
March			24-Mar	2-Apr		206.55	206.55	Boiler Tube Leak
April	2-Apr	4-Apr	2-Apr	4-Apr	44.02		44.02	Maintenance Outage - Boiler Casing Repairs
April	4-Apr	4-Apr	4-Apr	4-Apr	13.58		13.58	Reserve Shutdown

Company Name: Kentucky Power Company
Station Name - Unit Number: Mitchell Unit No. 1
For the Months of: January 1, 2014 to April 30, 2014

	MAINTENANCE				HOURS OF DURATION			
	Scheduled		Actual[1/]					
MONTH	From	To	From	To	Scheduled	Forced	Actual	REASON FOR DEVIATIONS FROM SCHEDULED MAINTENANCE OR REASON FOR FORCED OUTAGE, AS APPROPRIATE
January	12/30/2013	1/4/2014	12/30/2013	1/4/2014		92.9	92.9	Damage to #5 Turbine Bearing
January	1/4/2014	1/5/2014	1/4/2014	1/5/2014	15.2		15.2	Reserve Shutdown
January	1/11/2014	1/13/2014	1/11/2014	1/13/2014		31.2	31.2	LP Turbine Bearing Vibration
January	1/13/2014	1/13/2014	1/13/2014	1/13/2014	12.3		12.3	Reserve Shutdown
January	1/15/2014	1/16/2014	1/15/2014	1/16/2014		6.9	6.9	LP Turbine Bearing Vibration
January	1/16/2014	1/16/2014	1/16/2014	1/16/2014	7.8		7.8	Reserve Shutdown
January	1/21/2014	1/21/2014	1/21/2014	1/21/2014		10.4	10.4	LP Turbine Bearing Vibration
January	1/21/2014	1/21/2014	1/21/2014	1/21/2014	7.7		7.7	Reserve Shutdown
January	1/22/2014	1/22/2014	1/22/2014	1/22/2014		15.3	15.3	#1 Throttle Valve Failure
January	1/22/2014	1/23/2014	1/22/2014	1/23/2014	12.7		12.7	Reserve Shutdown
January	1/23/2014	1/23/2014	1/23/2014	1/23/2014		1.8	1.8	LP Turbine Bearing Vibration
February	2/5/2014	2/5/2014	2/5/2014	2/5/2014		5.3	5.3	LP Turbine Bearing Vibration
February	2/5/2014	2/6/2014	2/5/2014	2/6/2014	5.5		5.5	Reserve Shutdown
February	2/6/2014	2/7/2014	2/6/2014	2/7/2014		14.8	14.8	LP Turbine Bearing Vibration
February	2/7/2014	2/23/2014	2/7/2014	2/23/2014	384		384	Turbine Bearing Inspection & Repair
February	2/23/2014	2/25/2014	2/23/2014	2/25/2014	70.1		70.1	#1 Throttle Valve Repairs
March	3/8/2014	3/12/2014	3/8/2014	3/12/2014	111.5		111.5	First Reheat Turbine Leak
March	3/12/2014	3/13/2014	3/12/2014	3/13/2014	15.8		15.8	Reserve Shutdown
April	3/27/2014	4/3/2014	3/27/2014	4/3/2014		165.7	165.7	Air Heater Wash
April	4/3/2014	4/4/2014	4/3/2014	4/4/2014	13.6		13.6	Reserve Shutdown

Company Name: Kentucky Power
Station Name - Unit Number: Mitchell Unit No. 2
For the Months of January 1, 2014 to April 30, 2014

	MAINTENANCE				HOURS OF DURATION			
	Scheduled		Actual[1/]					
MONTH	From	To	From	To	Scheduled	Forced	Actual	REASON FOR DEVIATIONS FROM SCHEDULED MAINTANANCE OR REASON FOR FORCED OUTAGE, AS APPROPRIATE
January	1/11/2014	1/14/2014	1/11/2014	1/14/2014		88.4	88.4	Convection Pass Water Wall Tube Leak
January	1/14/2014	1/15/2014	1/14/2014	1/15/2014	8.7		8.7	Reserve Shutdown
January	1/22/2014	1/22/2014	1/22/2014	1/22/2014		6.2	6.2	BFP Injection Water Line Leak
January	1/22/2014	1/22/2014	1/22/2014	1/22/2014	10.5		10.5	Reserve Shutdown
April	4/18/2014	4/23/2014	4/18/2014	4/23/2014	140.9		140.9	Economizer Tube Leak
April	4/23/2014	4/24/2014	4/23/2014	4/24/2014	19.6			Reserve Shutdown
April	4/26/2014	4/30/2014				83.9	83.9	Economizer Tube Leak
April	4/30/2014	4/30/2014			12.9		12.9	Reserve Shutdown

Kentucky Power Company

REQUEST

List all existing fuel contracts categorized as long-term (i.e., one year or more in length). Provide the following information for each contract:

a. Supplier's name and address;
b. Name and location of production facility;
c. Date when contract was executed;
d. Duration of contract;
e. Date(s) of each contract revision, modification, or amendment;
f. Annual tonnage requirements;
g. Actual annual tonnage received since the contract's inception;
h. Percentage of annual requirements received during the contract's term;
i. Base price in dollars per ton;
j. Total amount of price escalations to date in dollars per ton; and
k. Current price paid for coal under the contract in dollars per ton (i + j).

RESPONSE

Please see Attachment 1 for the requested information.

WITNESS: Charles F West

This response is provided for the time period of November 1, 2013 through April 30, 2014 and lists all pertinent fuel contract information requested.

Please note that all contracts are annual fixed price agreements and do not escalate based on price indices. The response to "i" reflects the first year fixed price of the contract when executed. The response to "k" is the fixed price of the contract at the end of the review period (April 30, 2014).

BEECH FORK PROCESSING (Contract No. 08-901)

a. Beech Fork Processing, Inc., State Route 292, Fast Lane Building, Lovely, KY 41231.
b. Bear Branch Mine in Lawrence County, KY, and the Spurlock Loadout/Mine in Floyd County, KY.
c. June 13, 2008.
d. October 1, 2008 – February 28, 2014.
e. February 5, 2009, August 30, 2010 and January 27, 2011, September 9, 2011, December 7, 2011, March 23, 2012, October 23, 2012, February 6, 2013, and January 8, 2014.
f. 180,000 tons in 2008; 450,000 tons in 2009; 360,000 tons in 2010 and 2011; 46,692 tons in 2012; 173,844 tons in 2013; 16,164 tons in 2014.

g&h.

Year	Tons Received	Percent of Annual Requirements
2008	0	0%
2009	630,502	140%
2010	360,443	100%
2011	329,113	91%
2012	85,931	184%
2013	173,836	100%
2014	16,670	103%

i. $82.00 FOB Plant.
j. None.
k. $77.16 FOB Plant.

OHIO VALLEY RESOURCES, INC (Contract No. 05-900)

a. Ohio Valley Resources, Inc., 46226 National Road, St. Clairsville, OH 43950.
b. McElroy Mine, Marshall WV.
c. January 1, 2006.
d. January 1, 2007 – December 31, 2021.
e. January 2, 2014.
f. 2,000,000 tons per year from 2014 through 2021.

g&h.

Year	Tons Received	Percent of Annual Requirements
2014	311,653	16%

i. $58.055 FOB Plant**
j. None.
k. $58.055 FOB Plant.

*Based on requirements through April 30, 2014.
**Response reflects price as of January 1, 2014.

RHINO ENERGY, LLC (Contract No. 10-900)

a. Rhino Energy LLC, 424 Lewis Hargett Circle Suite 250, Lexington, KY 40503.
b. Bevins Branch Mine in Floyd County, KY.
c. August 18, 2010.
d. October 1, 2010 – June 30, 2014.
e. August 25, 2010 and September 19, 2013.
f. 30,000 tons from October through December of 2010; 480,000 tons per year for 2011 and 2012; 351,800 tons for 2013; 128,202 tons for January through June of 2014.

g&h.

Year	Tons Received	Percent of Annual Requirements
2010	30,000	100%*
2011	439,343	92%
2012	487,499	102%
2013	388,091	110%
2014	91,448	71%**

i. $73.00 FOB Plant.
j. None.
k. $78.45 FOB Plant.

* 11,904 tons over 2010 obligation, delivered in December 2010, were applied to the 2011 obligation.

**Based on requirements through April 2014.

S. M. & J., Inc (Contract No. 10-901)

a. S. M. & J., Inc, 17838 US Rt 23, Catlettsburg, KY 41129.
b. Diablo West Mine, Right Oakley Mine, Diablo 2A Mine, and Diablo 4 Mine all located in Magoffin County, KY.
c. November 29, 2010.
d. January 1, 2011 – March 31, 2014.
e. January 9, 2014 and February 12, 2014.
f. 240,000 Tons per year for 2011 and 2012; 204,372 tons per year for 2013; 35,634 tons per year for January through March of 2014.

g&h.

Year	Tons Received	Percent of Annual Requirements
2011	199,829	83%
2012	276,027	115%
2013	207,231	101%
2014	36,409	102%

i. $78.15 FOB Plant.
j. None.
k. $78.15 FOB Plant.

S. M. & J., Inc (Contract No. 10-900)

a. S. M. & J., Inc, 17838 US Rt 23, Catlettsburg, KY 41129.
b. Diablo West Mine, Right Oakley Mine, Diablo 2A Mine, and Diablo 4 Mine all located in Magoffin County, KY.
c. November 17, 2011.
d. January 1, 2011 – December 31, 2013.
e. February 11, 2014.

f. 0 tons for 2014.

g&h.

Year	Tons Received	Percent of Annual Requirements
2014	7,875	*

i. $68.70 FOB Barge.
j. None.
k. $68.70 FOB Barge.

*2014 tons are carryover from 2013. There were no annual requirements for 2014.
**Response reflects price as of January 1, 2014.

SOUTHERN COAL SALES (Contract No. 12-900)

a. Southern Coal Sales Corporation, 302 S. Jefferson Street, Suite 600, Roanoke, VA 24011.
b. Bent Mountain Mine in Pike County, KY, Bevins Branch Mine in Pike County, KY, Beech Creek Mine in Pike County, KY, Yellow Mountain Mine in Pike County, KY, and WV3 Mine in Logan County, WV.
c. November 28, 2012.
d. January 1, 2013 – December 31, 2014.
e. None.
f. 41,667 Tons per month for 2013 through 2014.

g&h.

Year	Tons Received	Percent of Annual Requirements
2013	246,703	49%
2014	198,559	40%*

i. $72.60 FOB Plant.
j. None.
k. $76.60 FOB Plant.

*Based on requirements through April 2014.

SOUTHERN COAL SALES (Contract No. 12-901)

a. Southern Coal Sales Corporation, 302 S. Jefferson Street, Suite 600, Roanoke, VA 24011.
b. Bent Mountain Mine in Pike County, KY, Bevins Branch Mine in Pike County, KY, Beech Creek Mine in Pike County, KY, Yellow Mountain Mine in Pike County, KY, and WV3 Mine in Logan County, WV.
c. November 28, 2012.
d. January 1, 2013 – December 31, 2013.
e. January 2, 2014 and April 30, 2014.
f. 83,333 Tons per month for 2013 through 2014.

g&h.

Year	Tons Received	Percent of Annual Requirements
2014	40,680	*

i. $65.50 FOB Plant.
j. None.
k. $76.12 FOB Plant.

*2014 tons are carryover from 2013. There were no annual requirements for 2014.

Kentucky Power Company

REQUEST

a. State whether Kentucky Power regularly compares the price of its coal purchases to those paid by other electric utilities.

b. If yes, state:

(1) How Kentucky Power's prices compare with those of other utilities for the review period. Include all prices used in the comparison in cents per MMbtu.

(2) The utilities that are included in this comparison and their locations.

RESPONSE

a. The Company performs a comparison of its coal purchases at least twice a year. Additionally, all purchase decisions are evaluated against the market at the time of the purchase to ensure the competitiveness of procurement practices.

b. (1) and (2) The following table contains a comparison of Kentucky Power's fuel prices to fuel prices of other utilities. The fuel cost data here was obtained from Velocity Suites which is a search engine that, in this case, used monthly fuel cost information from the U.S. Energy Information Agency (EIA) Form 923 for the period of November 1, 2013 through April 30, 2014.

This table shows that, for the companies included in the comparison, Kentucky Power has the highest fuel costs for the review period on a cents per million British Thermal Units (MMBTU) basis. However, it should be noted that the fuel being delivered to these facilities may not be of the same quality or mixture as that being delivered to Kentucky Power. A review of the sulfur data shows that Kentucky Power purchased coal with the second lowest sulfur content of all of the companies included in the comparison.

Operator	State	Calculated Cents/MMBtu
Kentucky Power Company	KY	295.03
East Kentucky Power Coop	KY	279.55
Tennessee Valley Authority	TN	253.26
Kentucky Utilities Co	KY	253.24
Monongahela Power Co	WV	241.02
Big Rivers Electric Corp	KY	239.46
Louisville Gas & Electric Co	KY	233.48
Duke Energy Kentucky	OH	223.91

For additional reference, the table below compares companies purchasing a lower sulfur coal than the first comparison group. In this comparison, Kentucky Power has the second lowest fuel costs for the review period on a cents per million British Thermal Units (MMBTU) basis. However, it should be noted that the fuel being delivered to these facilities may not be of the same quality or mixture as that being delivered to Kentucky Power. A review of the sulfur data shows that Kentucky Power purchased coal with sulfur content roughly in the middle of the companies included in the comparison.

Operator	State	Calculated Cents/MMBtu
South Carolina Generating Co Inc	SC	403.48
Duke Energy Carolinas	NC	382.74
South Mississippi Electric Power Association	MS	377.23
Duke Energy Progress	NC	348.96
Gainesville Regional Utilities	FL	336.67
Virginia Electric & Power Co	VA	315.69
Kentucky Power Co	KY	295.03

WITNESS: Charles F West

Kentucky Power Company

REQUEST

State the percentage of Kentucky Power's coal, as of the date of this Order, that is delivered by:

a. Rail;
b. Truck; or
c. Barge.

RESPONSE

From November 1, 2013 through April 30, 2014, the percentage of Kentucky Power's coal delivery method* is as follows:

a. Rail: 0%
b. Truck: 42%
c. Barge: 33%

*Please note that a portion of Mitchell generating station's coal is delivered by a belt conveyor system from an adjacent mine. The remaining 25% of coal not accounted for in the percentage above was delivered by belt conveyor system.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

a. State Kentucky Power's coal inventory level in tons and in number of days' supply as of April 30, 2014. Provide this information by generating station and in the aggregate.

b. Describe the criteria used to determine number of days' supply.

c. Compare Kentucky Power's coal inventory as of April 30, 2014, to its inventory target for that date for each plant and for total inventory.

d. If actual coal inventory exceeds inventory target by ten days' supply, state the reasons for excessive inventory.

e. (1) State whether Kentucky Power expects any significant changes in its current coal inventory target within the next 12 months.

(2) If yes, state the expected change and the reasons for this change.

RESPONSE

a. As of April 29, 2014 Kentucky Power's actual coal inventory levels were as follows:

Big Sandy: 288,441 tons, or 28 days of supply
Mitchell High Sulfur: 155,840 tons, or 21 days of supply
Mitchell Low Sulfur: 243,973 tons, or 33 days of supply

b. Days' supply is determined by dividing the tons of coal in storage by the full load burn rate (tons per day).

For Big Sandy, $\dfrac{\text{288,441 tons in storage as of 04/29/2014}}{\text{10,250 (full load burn rate – tons/day)}}$ = 28 days

For Mitchell High Sulfur, $\frac{\text{155,840 tons in storage as of 04/29/2014}}{\text{7,430 (full load burn rate – tons/day)}}$ = 21 days

For Mitchell Low Sulfur, $\frac{\text{243,973 tons in storage as of 04/29/2014}}{\text{7,430 (full load burn rate – tons/day)}}$ = 33 days

c. As of April 29, 2014,

Big Sandy: Target Inventory Days = 30 days, Actual Inventory Days = 28 days
(2 days under target)
Mitchell High Sulfur: Target Inventory Days = 15 days, Actual Inventory Days = 21 days
(6 days over target)
Mitchell Low Sulfur: Target Inventory Days = 30 days, Actual Inventory Days = 33
(3 days over target)

d. N/A.

e. (1) Yes.

(2) Due to the planned retirement of Big Sandy Unit 2 in mid-2015, inventory levels are forecasted to decline until the unit retires. Once the unit retires, the inventory target will change to reflect the retirement.

Kentucky Power does not expect any significant changes in the coal inventory target for the Mitchell plant within the next 12 months.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

a. State whether Kentucky Power has audited any of its coal contracts during the period from November 1, 2013, through April 30, 2014.

b. If yes, for each audited contract:

(1) Identify the contract;
(2) Identify the auditor;
(3) State the results of the audit; and
(4) Describe the actions that Kentucky Power took as a result of the audit.

RESPONSE

a. Kentucky Power did not audit any of its coal contracts during the review period from November 1, 2013 to April 30, 2014.

b. N/A.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

a. State whether Kentucky Power has received any customer complaints regarding its FAC during the period from November 1, 2013, through April 30, 2014.

b. If yes, for each complaint, state:

(1) The nature of the complaint; and
(2) Kentucky Power's response.

RESPONSE

a-b. Kentucky Power did not receive any customer complaints regarding its FAC during the review period.

WITNESS: John A Rogness III

Kentucky Power Company

REQUEST

State whether Kentucky Power is currently involved in any litigation with its current or former coal suppliers.

b. If yes, for each litigation:

(1) Identify the coal supplier;
(2) Identify the coal contract involved;
(3) State the potential liability or recovery to Kentucky Power;
(4) List the issues presented; and
(5) Provide a copy of the complaint or other legal pleading that initiated the litigation and any answers or counterclaims. If a copy has previously been filed with the Commission, provide the date on which it was filed and the case in which it was filed.

c. State the current status of all litigation with coal suppliers.

RESPONSE

a. Kentucky Power is not currently involved in any litigation with its current or former coal suppliers.

b. N/A.

c. N/A.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

During the period from November 1, 2013, through April 30, 2014, have there been any changes to Kentucky Power's written policies and procedures regarding its fuel procurement?

b. If yes:

(1) Describe the changes;
(2) Provide the written policies and procedures as changed;
(3) State the date(s) the changes were made; and
(4) Explain why the changes were made.

c. If no, provide the date Kentucky Power's current fuel procurement policies and procedures were last changed, when they were last provided to the Commission, and identify the proceeding in which they were provided.

RESPONSE

a. There were no changes to Kentucky Power's written policies and procedures regarding its fuel procurement during the period from November 1, 2013 through April 30, 2014.

b. N/A.

c. Kentucky Power's Fuel Procurement Policy was last updated in September 2012 and was provided to the Commission in Case No. 2012-00550 in March 2013.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

a. State whether Kentucky Power is aware of any violations of its policies and procedures regarding fuel procurement that occurred prior to or during the period from November 1, 2013, through April 30, 2014.

b. If yes, for each violation:

(1) Describe the violation;
(2) Describe the action(s) that Kentucky Power took upon discovering the violation; and
(3) Identify the person(s) who committed the violation

RESPONSE

a. Kentucky Power is not aware of any violations of its policies and procedures regarding fuel procurement prior to or during the period from November 1, 2013 to April 30, 2014.

b. N/A.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

Identify and explain the reasons for all changes in the organizational structure and personnel of the departments or divisions that are responsible for Kentucky Power's fuel procurement activities that occurred during the period from November 1, 2013, through April 30, 2014.

RESPONSE

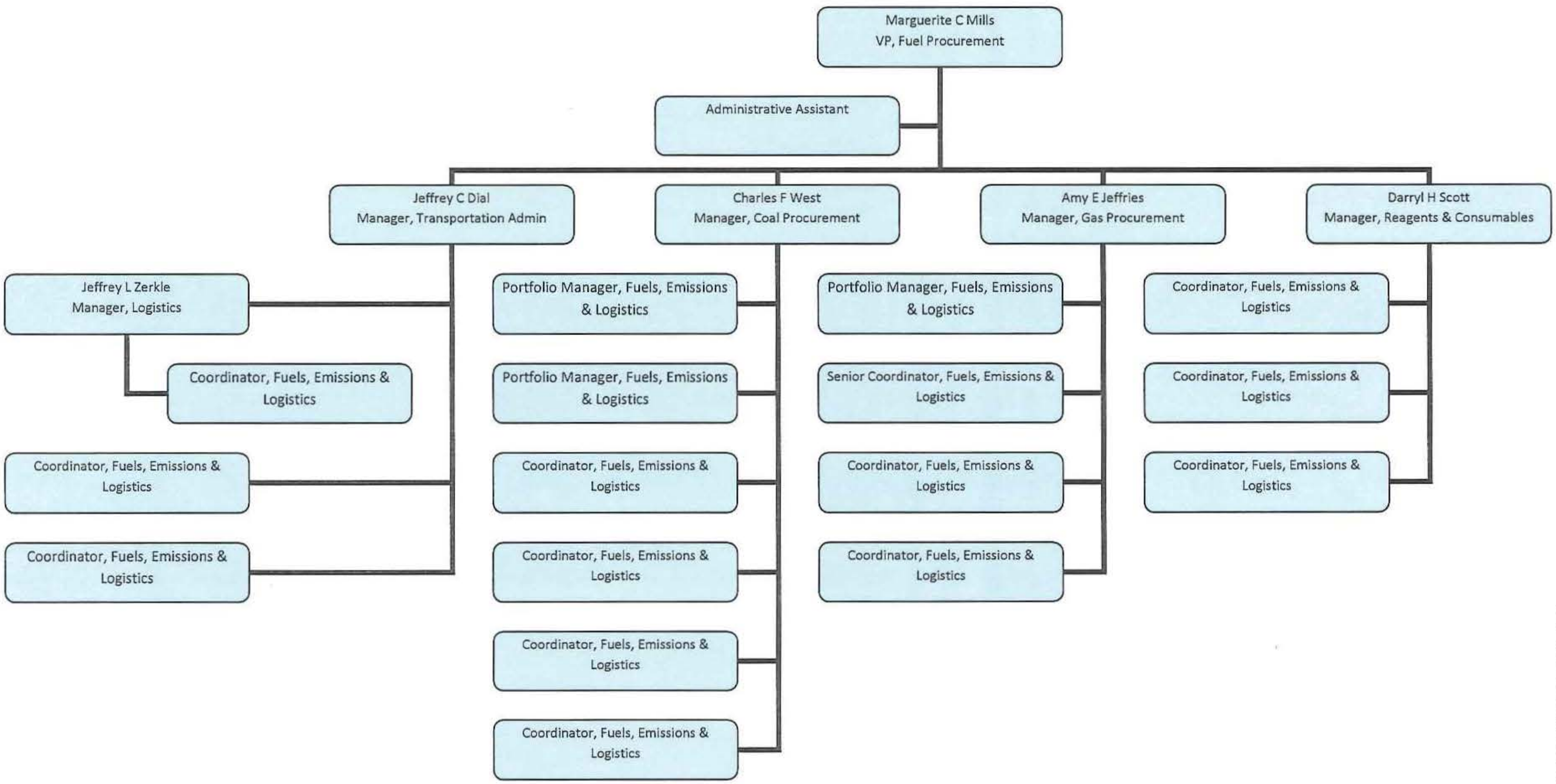
As a result of corporate separation due to deregulation in Ohio, the following organizational changes involving personnel responsible for Kentucky Power's fuel procurement were effective as of January 1, 2014:

- Marguerite Mills is Vice President of Fuel Procurement within the Regulated Commercial Operations group,
- Charles West is Manager of Fuel Procurement within the Regulated Commercial Operations group, and
- Darryl H. Scott is Manager of Reagents & Coal Combustion Products. Fuel oil procurement is now also managed within this group.

Please see Attachment 1 for organizational chart as of January 1, 2014.

WITNESS: Charles F West

American Electric Power Company
Organization Chart – Fuel Procurement
As of January 31, 2014



Kentucky Power Company

REQUEST

a. Identify all changes that Kentucky Power has made during the period under review to its maintenance and operation practices that also affect fuel usage at Kentucky Power's generation facilities.

b. Describe the impact of these changes on Kentucky Power's fuel usage.

RESPONSE

There have been no maintenance or operation practice changes during the period at the Big Sandy Plant or Mitchell Plant.

WITNESS: Daniel L. Moyer and Aaron M. Sink

Kentucky Power Company

REQUEST

List each written coal-supply solicitation issued during the period from November 1, 2013, through April 30, 2014.

a. For each solicitation, provide the date of the solicitation, the type of solicitation (contract or spot), the quantities solicited, a general description of the quality of coal solicited, the time period over which deliveries were requested, and the generating unit(s) for which the coal was intended.

b. For each solicitation, state the number of vendors to whom the solicitation was sent, the number of vendors who responded, and the selected vendor. Provide the bid tabulation sheet or corresponding document that ranked the proposals.

   (This document should identify all vendors who made offers.) State the reasons for each selection. For each lowest-cost bid not selected, explain why the bid was not selected.

RESPONSE

Kentucky Power did not issue written coal supply solicitations during the period from November 1, 2013 to April 30, 2014.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

List each oral coal-supply solicitation issued during the period from November 1, 2013, through April 30, 2014.

a. For each solicitation, state why the solicitation was not written, the date(s) of the solicitation, the quantities solicited, a general description of the quality of coal solicited, the time period over which deliveries were requested, and the generating unit(s) for which the coal was intended.

b. For each solicitation, identify all vendors solicited and the vendor selected. Provide the tabulation sheet or other document that ranks the proposals.

(This document should identify all vendors who made offers.) State the reasons for each selection. For each lowest-cost bid not selected, explain why the bid was not selected.)

RESPONSE

Kentucky Power issued two oral coal supply solicitations during the period from November 1, 2013 to April 30, 2014.

a.

	Oral Solicitation #1	Oral Solicitation #2
Date of Solicitation	March 10, 2014	April 11, 2014
Quantities Solicited	200,000 Tons	150,000 Tons
Description of Quality of Coal Solicited	NYMEX Quality	NYMEX Quality
Time Period Requested for Deliveries	July 1, 2014 to December 31, 2014	May 1, 2014 – September 30, 2014
Generating Unit(s) Intended	Mitchell	Big Sandy
Why Solicitation Was Not Written	Due to the low volume of coal being requested and the low price of NYMEX quality coal at the time.	After the winter, there was an immediate need for coal at Big Sandy. Rail was unavailable at the time, so all suppliers who were known to have crushed coal deliverable by truck were solicited.

b. Please see Attachments 1 & 2 for all vendors solicited and documentation that ranks proposals. Confidential treatment is being sought for portions of Attachments 1 & 2.

WITNESS: Charles F West

AEP - 2014 tons
CAPP PHONE SOLICITATION 03-10-2014

Company	Shipping Location	Total Tons	Term	Coal Price	Barge/Rail Rate	BTU	SO2	Ash %	Del $/MMBtu
Maple Coal Sales	KR 74.6	[redacted]	7/1/2014 - 12/31/2014	[redacted]	[redacted]	12,000	1.60	12.50%	[redacted]
Mercuria*	OR 300-316	300,000	7/1/2014 - 12/31/2014	$61.65	$5.64	12,000	1.67	13.50%	$2.92
River Trading	KR 69.1	[redacted]	7/1/2014 - 12/31/2014	[redacted]	[redacted]	12,000	1.80	13.00%	[redacted]
SM&J		[redacted]	7/1/2014 - 12/31/2014	[redacted]	[redacted]	*12,000*	1.67	12.00%	[redacted]
Patriot Coal Sales	KR 73.3	[redacted]	7/1/2014 - 12/31/2014	[redacted]	[redacted]	12,000	1.60	13.50%	[redacted]
Central	OR 300-316	[redacted]	7/1/2014 - 12/31/2014	[redacted]	[redacted]	12,000	1.67	13.50%	[redacted]
Argus / Pevier	BS 7.7	[redacted]	04/1/2014 - 12/31/2014	[redacted]	[redacted]	12,000	1.60	10.50%	[redacted]
Trafigura			04/1/2014 - 06/30/14						
Alpha Coal Sales									
Peerless									

made an offer at a lower cost than the winning offer. This coal was no longer available for purchase at the time of awarding bids.

** Winning Offer*

KPCO - BIG SANDY - 2014 tons
NYMEX TRUCK DELIVERED PHONE SOLICITATION

Company	Tons	Term	Coal Price	Delivery Method	Additional Delivery Fee	BTU	SO2	Ash %	Del $/MMBtu
Beechfork Processing*	132,000	May-Sept	$ 66.00	truck	$ -	12,000	1.60	10.50%	$ 2.750
SM&J*	150,000	May-Sept	$ 67.00	truck	$ -	12,000	1.67	10.50%	$ 2.792
Rhino	[redacted]	May-Sept	[redacted]		[redacted]	12,000	1.67	13.50%	[redacted]

*Winning Offer

Kentucky Power Company

REQUEST

a. List all intersystem sales during the period under review in which Kentucky Power used a third party's transmission system.

b. For each sale listed above:

(1) Describe how Kentucky Power addressed, for FAC reporting purposes, the cost of fuel expended to cover any line losses incurred to transmit its power across the third party's transmission system; and

(2) State the line-loss factor used for each transaction and describe how that line-loss factor was determined.

RESPONSE

a. & b. Beginning on June 1, 2007, based on FERC Order EL06-055, PJM modified the Locational Marginal Pricing (LMP) approach to calculate transmission line loss costs on a marginal basis. The new LMP calculation reflects the full marginal cost of serving an increment of load at each bus from each resource associated with an eligible energy offer. The LMP price will be the sum of three separate components: System Energy Price, Congestion Price and Loss Price. Therefore, each spot market energy customer pays an energy price that includes the full marginal cost of energy for delivering an increment of energy to the purchaser's location. Market buyers are assessed for their incremental impact on transmission line losses resulting from total load scheduled to be served from the PJM Spot Energy Market in the day-ahead energy market at the same day-ahead loss price applicable at the relevant load bus.

Market sellers are assessed for their incremental impact on transmission line losses resulting from energy scheduled for delivery in the day-ahead market at the day-ahead loss prices applicable to the relevant resource bus.

Transactions are balanced in the real-time market using the same calculation, but are based on deviation at each bus from the day-ahead using the real time loss price.

WITNESS: John A Rogness III

Kentucky Power Company

REQUEST

Describe each change that Kentucky Power made to its methodology for calculating intersystem sales line losses during the period under review.

RESPONSE

Kentucky Power did not make any changes to its methodology for calculating intersystem sales line losses during the review period.

WITNESS: John A Rogness III

Kentucky Power Company

REQUEST

State whether, during the period under review, Kentucky Power has solicited bids for coal with the restriction that it was not mined through strip mining or mountaintop removal. If yes, explain the reasons for the restriction on the solicitation, the quantity in tons and price per ton of the coal purchased as a result of this solicitation, and the difference between the price of this coal and the price it could have obtained for the coal if the solicitation had not been restricted.

RESPONSE

No. During the review period, Kentucky Power did not solicit bids for coal with the restriction that it was not mined through strip mining or mountaintop removal.

WITNESS: Charles F West

Kentucky Power Company

REQUEST

Provide a detailed discussion of any specific generation efficiency improvements Kentucky Power has undertaken during the period under review.

RESPONSE

There have been no efficiency improvements during the review period.

WITNESS: Daniel L. Moyer and Aaron M. Sink

Kentucky Power Company

REQUEST

State whether any PJM Interconnection, LLC costs were included in Kentucky Power's monthly FAC filings during the period under review. If yes, provide the amount of the costs by month and by type of cost.

RESPONSE

Certain PJM costs were included in Kentucky Power's monthly FAC filings during the period under review. Please see Attachment 1 to this response for costs by month.

WITNESS: John A Rogness III

Kentucky Power Company
PJM Costs included in the FAC
November 1, 2013 to April 30, 2014

Expense Month	Transaction Class		Fuel Cost
November 2013	SPOT MARKET ENERGY - BAL	$	136,407
November 2013	SPOT MARKET ENERGY - DA	$	75,667
November 2013	MARGINAL LINE LOSS	$	505,637
December 2013	SPOT MARKET ENERGY - BAL	$	8,976
December 2013	MARGINAL LINE LOSS	$	685,698
January 2014	SPOT MARKET ENERGY - BAL	$	69,279
January 2014	SPOT MARKET ENERGY - DA	$	82,709
January 2014	MARGINAL LINE LOSS	$	4,390,858
February 2014	SPOT MARKET ENERGY - BAL	$	53,803
February 2014	MARGINAL LINE LOSS	$	1,692,237
March 2014	SPOT MARKET ENERGY - BAL	$	104,108
March 2014	SPOT MARKET ENERGY - DA	$	111,173
March 2014	MARGINAL LINE LOSS	$	1,897,456
April 2014	SPOT MARKET ENERGY - BAL	$	875
April 2014	MARGINAL LINE LOSS	$	1,031,716
	TOTAL	$	10,846,597

Kentucky Power Company

REQUEST

Explain how purchase power costs are accounted for in the calculation of the FAC when Kentucky Power experiences a planned generation outage and purchases power to meet load (i.e., is the entire amount of the purchase power recorded in the calculation, or is there a limit as to the amount recorded?). If there is a limit, explain the basis for the limitation and how it is calculated. If there is no limit, explain the basis for including 100 percent of the purchase power costs.

RESPONSE

In accordance with 807 KAR 5:056 Section 1(3), KRS 278.160, and the Commission's Order dated February 7, 2005 in Case No. 2004-00430, Kentucky Power includes "the actual identifiable fossil and nuclear fuel costs associated with energy purchased for … [non-economic reasons]" other than purchases to substitute for forced outages, and the net energy cost of energy purchases, exclusive of capacity or demand charges…" purchased on an economic dispatch basis or in connection with a schedule outage. There are no "limits" except as required by the regulation and noted above.

WITNESS: John A Rogness III

Kentucky Power Company

REQUEST

Explain how purchase power costs are accounted for in the calculation of the FAC when Kentucky Power is not experiencing a generation outage but must purchase power in order to meet demand (i.e., is the entire amount of the purchase power recorded in the calculation, or is there a limit as to the amount recorded?). If there is a limit, explain the basis for the limitation and how it is calculated. If there is no limit, explain the basis for including 100 percent of the purchase power costs.

RESPONSE

Kentucky Power includes 100% of the purchased power costs that it may incur during a time of an energy shortage that is not directly linked to a forced outage in the FAC.

Please see also the response to KPSC 1-26.

WITNESS: John A Rogness III

Kentucky Power Company

REQUEST

State whether it was anticipated that, with the transfer of 50 percent of the Mitchell station to Kentucky Power, fuel costs to native-load customers would decrease. If a decrease was anticipated but has not materialized, provide an explanation.

RESPONSE

The Company anticipated that the cost of coal for the Mitchell units would be cheaper than the cost of coal for the Big Sandy units, and that has materialized over the first part of 2014.

What was not anticipated was the polar vortex that occurred during the first quarter of 2014. The polar vortex created an unanticipated increase in native load energy consumption and the opportunity for increased off-system sales. As part of the Stipulation and Settlement agreement in Case No. 2012-00578, the Company had the opportunity to keep all off-system sales margins over the $15.3 million level currently in base rates in return for receiving only a fraction of its Mitchell-related costs. To cover the increased internal load and to "earn back" a portion of the Mitchell-related costs and revenue through off-system sales as permitted under the Stipulation and Settlement Agreement, the Company, at the direction of PJM, ran all four of its owned generation units as much as possible. Running all four units increased the amount of "no-load costs" that have been historically and properly allocated to internal customers.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Provide Kentucky Power's definition of "no load costs".

a. Explain in detail how these costs are calculated for each generating unit.

b. Explain how the "no load costs" are allocated between native-load sales and off-system sales each hour.

c. State the length of time "no load costs" have been allocated in this manner.

d. By month and generating unit, provide the amount of "no load costs" that have been allocated to native-load customers from November 1, 2012, through April 30, 2014.

e. If "no load costs" have been allocated 100 percent to native-load customers, state the amount, by month, that would have been allocated to native-load customers if "no load costs" had been considered with all other fuel costs and allocated according to economic dispatch.

f. State whether any "no load costs" are being recovered through base rates. If yes, provide the amount by generating unit that was included in the test year in the utility's most recent adjudicated base rate case and state whether the costs are being double-recovered through the FAC.

g. State whether "no load costs" are discussed in Kentucky Power's Cost Allocation Manual. If yes, provide excerpts of the manual wherein it is discussed.

h. For each month under the review period and for each generating unit (Big Sandy units 1 and 2, Rockport units 1 and 2, and Mitchell units 1 and 2), provide the following:

(1) The total MWh generated;
(2) The dollar amount of fuel costs allocated to native-load customers;
(3) The amount of MWh allocated to the native-load customers;
(4) The dollar amount of fuel costs allocated to off-system sales;
(5) The amount of MWh allocated to off-system sales;
(6) The percent of each unit's MWh allocated to native-load customers; and
(7) Each unit's "no load costs".

i. During the years that the American Electric Power Interconnection Agreement was in place, provide the dates when changes were made in how fuel costs were allocated between native-load and off-system sales and describe the changes made.

j. State whether Kentucky Power has discussed "no load costs" with the Commission prior to the meeting held on June 26, 2014, at the Commission's offices. If yes, identify the proceeding.

RESPONSE

"No load costs" are the fixed fuel and consumable costs incurred when a unit is in operation that are not dependent on the output level of the unit. In other words, these are the costs incurred in any hour to ensure that a generating unit is online and available to serve internal load, which has long been a principle of how AEP dispatches its units.

a. "No load costs" are calculated using second degree polynomial equations which are used to model the efficiency of a generating unit at various levels of output. These equations take the form:

"REQUIRED HEAT INPUT = A + B*MWh + C* MWh^2"

and model the heat input required to generate the specified "MWh" of generation. The equation coefficients are derived based on the design of the unit and are unique to each unit based on its configuration and operation.

"No load costs" are the fixed costs of fuel and consumables needed to supply the Required Heat Input in the formula above with the formula evaluated at zero MWh output (ie. the heat input specified by the A coefficient).

b. "No load costs" are not associated with specific increments of generation, and thus have never been allocated to off-system sales and remain with native load costs. Economic dispatch allocates generation costs based on incremental changes associated with increasing or decreasing unit output. Because "no load costs" do not change when generation is increased or decreased, economic dispatch does not provide a basis for allocation of "no load costs".

This is a historical practice that dates back as far as the Company has been able to determine -- at least 30 years -- and nothing was found that suggested any other treatment prior to that period. Units were and are first and always available for internal load. Units that are on-line in a given hour are assumed first to satisfy internal load, and only the controllable dispatch between the unit minimums and maximums may be available to make off-system sales (OSS) if additional economic power is available and it is not needed for internal load.

As a result, dispatch between unit minimums and maximums for each hour was analyzed in the post-period cost reconstruction settlement process with the units of all AEP Interconnection Agreement members "pooled" together. In each hour, for the entire AEP East fleet (which in 2013 consisted of 22 plants or 59 units excluding renewable sources which are directly assigned to internal load), the unit with the very highest \$/MWh cost of the last MWh it dispatched, was the first MWh to be assigned to off-system sales (OSS) for that hour. The cost associated with that MWh is the cost as calculated using the heat input curve as described in response to subpart (a) above. For each hour, this OSS allocation continued, always selecting the next highest cost MWh, which is the cost of producing the last MWh (that has not already been assigned to OSS) from the highest cost unit, until costs were allocated to all OSS. The remaining MWhs and costs are what were used to serve the internal load of all of the members.

This treatment was further supported in Article 7.5. of the AEP Interconnection Agreement regarding settlement of power sales to foreign companies, "Electric Power and energy for such sales shall be considered to be supplied from the highest cost source carrying load on the System, *excluding sources operated for minimum operating requirements*, or,,," (emphasis added).

For this reason, AEP's consistent, historical practice of treating "no load costs" in this manner did not change in 2014. Only now, rather than all of the units of the AEP East fleet, the OSS are assigned using only KPCo's units.

Finally, this treatment is economically sound and mirrors the real time dispatch of units. For example, if the Company's fleet is on-line serving only its native load, the no-load cost are already being incurred. If the market then requests additional power at a \$30 /MWh price and a Company unit can dispatch another MWh at \$28/MWh, it is economic to do so.

The resulting real margin is $2 ($30 - $28) and this $2 can be shared in an equitable fashion between the Company's customers and shareholders -- in short, everyone benefits. If however, some artificial means is used to subsequently allocate $3 of fixed no load fuel cost to the cost basis of this sale, increasing the cost basis to $31 ($28 + $3), the resulting margin now becomes -$1 ($30 - $31), which is a loss and signals that the sale was uneconomic. This is a distorted result and leads to the irrational incentive to serve only internal load and make no OSS even if the sale is truly economic.

c. "No load costs" have been assigned to native load in this manner since at least 1984.

d. Please see subpart (h)(7) below.

e. Economic dispatch does not result in an allocation of "no-load costs." Please refer to subpart (b) above.

f. There is no double-recovery. The fuel portion of "no load costs" is excluded from base rates and is recovered only through the fuel recovery mechanism of base fuel with the fuel adjustment clause. A portion of environmental consumable costs is also classified as "no load costs" and is recovered through base rates or the environmental surcharge.

g. "No load costs" are not addressed within the Cost Allocation Manual.

h. (1-6) Please Attachments 1 to this response. For Mitchell and Rockport plants, both total and allocated fuel costs are provided at the unit level. For Big Sandy, the total fuel costs are only available at the plant level.

(7) Please see Attachment 2 to this response.

i. AEP is not aware of any changes in the way that "no load costs" have been allocated since at least 1984. It has been AEP's consistent, historical method to allocate "no load costs" to internal load for at least 30 years and possibly longer.

j. Kentucky Power is not aware of any proceeding in which inquiry has been made regarding "no load costs".

WITNESS: Ranie K. Wohnhas

	Generation (MWh)						Fuel Cost (in $1000)					
	November 2013	December 2013	January 2014	February 2014	March 2014	April 2014	November 2013	December 2013	January 2014	February 2014	March 2014	April 2014
PLANT/UNIT TOTALS (Question: 29.h.(1))												
Big Sandy 1	35,583	124,779	141,915	154,971	149,784	78,200						
Big Sandy 2	286	255,015	469,235	425,614	146,071	399,940						
Big Sandy Plant							2,075.97	13,224.76	19,054.15	17,147.65	9,283.76	14,450.19
Rockport 1 KP AEG	113,853	137,910	135,241	94,746	143,800	109,938	2,907.93	3,497.66	3,274.17	2,459.42	3,191.50	2,790.04
Rockport 2 KP AEG	126,399	135,072	128,673	95,240	138,629	90,024	3,204.09	3,396.93	3,080.78	2,539.07	3,081.68	2,352.53
Mitchell 1 KP			139,495	52,281	180,246	217,935			4,450.96	1,968.71	5,522.94	5,255.91
Mitchell 2 KP			219,535	249,044	250,451	150,979			6,403.18	7,335.77	6,347.64	4,294.64
ALLOCATION TO OFF-SYSTEM (Question: 29.h.(5))							**(Question: 29.h.(4))**					
Big Sandy 1	5,467	45,784	58,702	79,303	49,943	42,678	174.96	2,872.68	1,697.45	2,353.30	1,517.60	1,264.62
Big Sandy 2	0	126,687	200,463	224,174	93,761	241,962	0.00	6,529.53	4,934.04	5,778.34	2,250.13	5,781.29
Big Sandy Plant												
Rockport 1 KP AEG	17,421	50,799	57,057	49,491	53,897	64,711	406.40	1,178.97	1,262.86	1,167.49	1,207.74	1,480.58
Rockport 2 KP AEG	18,332	43,615	49,753	38,437	45,385	50,853	425.94	1,004.96	1,090.06	895.53	997.26	1,150.85
Mitchell 1 KP			26,741	3,248	79,491	103,339			637.28	77.76	1,960.97	1,881.98
Mitchell 2 KP			48,331	34,638	74,136	67,373			1,149.15	866.17	1,738.60	1,207.18
ALLOCATION TO NATIVE LOAD (Question: 29.h.(3))							**(Question: 29.h.(2))**					
Big Sandy 1	30,116	78,995	83,213	75,668	99,841	35,522						
Big Sandy 2	286	128,328	268,772	201,440	52,310	157,978						
Big Sandy Plant							1,901.01	3,822.55	12,422.66	9,016.01	5,516.03	7,404.28
Rockport 1 KP AEG	96,432	87,111	78,184	45,255	89,903	45,227	2,501.53	2,318.69	2,011.31	1,291.93	1,983.76	1,309.46
Rockport 2 KP AEG	108,068	91,457	78,920	56,804	93,244	39,171	2,778.15	2,391.97	1,990.72	1,643.53	2,084.42	1,201.68
Mitchell 1 KP	0	0	112,754	49,033	100,755	114,596	0.00	0.00	3,813.68	1,890.95	3,561.97	3,373.93
Mitchell 2 KP	0	0	171,204	214,406	176,315	83,606	0.00	0.00	5,254.03	6,469.60	4,609.04	3,087.46
PERCENT MWh ALLOCATED TO NATIVE LOAD (Question: 29.h.(6))												
Big Sandy 1	84.64%	63.31%	58.64%	48.83%	66.66%	45.42%						
Big Sandy 2	100.00%	50.32%	57.28%	47.33%	35.81%	39.50%						
Big Sandy Plant												
Rockport 1 KP AEG	84.70%	63.17%	57.81%	47.76%	62.52%	41.14%						
Rockport 2 KP AEG	85.50%	67.71%	61.33%	59.64%	67.26%	43.51%						
Mitchell 1 KP	0.00%	0.00%	80.83%	93.79%	55.90%	52.58%						
Mitchell 2 KP	0.00%	0.00%	77.98%	86.09%	70.40%	55.38%						

No Load Costs from November 2012 through April 2014 for Kentucky Units (29.d & 29 h -7)

Periods	Big Sandy 1	Big Sandy 2	Mitchell 1 KP	Mitchell 2 KP	Rockport 1 KP AEG	Rockport 2 KP AEG	Grand Total
2012/11	0.010	0.000			192,970.562	266,952.658	459,923.230
2012/12	472,697.692	933,187.323			284,976.679	292,890.789	1,983,752.483
2013/01	480,312.173	3,345,690.500			301,204.928	311,715.001	4,438,922.603
2013/02	420,971.973	3,453,936.159			281,499.032	14,706.970	4,171,114.134
2013/03	520,102.982	5,198,100.614			312,367.103	0.000	6,030,570.699
2013/04	86,450.012	4,988,347.040			314,101.775	0.000	5,388,898.827
2013/05	61,970.029	519,039.954			334,150.241	102,251.519	1,017,411.742
2013/06	593,905.539	118,387.646			211,545.923	316,494.998	1,240,334.106
2013/07	640,957.696	114,293.626			381,620.196	397,208.135	1,534,079.653
2013/08	629,727.982	0.000			381,467.903	336,661.447	1,347,857.333
2013/09	576,437.181	0.000			343,950.122	336,297.147	1,256,684.451
2013/10	73,942.887	0.000			229,045.228	351,695.447	654,683.562
2013/11	165,016.741	42,523.961			327,021.996	324,896.494	859,459.193
2013/12	970,391.571	5,901,922.839			330,932.196	333,547.652	7,536,794.258
2014/01	448,955.898	4,700,457.677	1,730,564.379	2,006,349.462	314,973.515	310,999.875	9,512,300.806
2014/02	400,241.534	3,802,847.804	707,862.363	2,131,025.841	226,435.358	241,648.940	7,510,061.840
2014/03	499,222.214	1,535,995.926	1,706,322.712	2,227,440.182	409,244.657	403,847.803	6,782,073.495
2014/04	276,695.127	4,250,145.342	1,530,893.445	1,114,711.762	368,710.179	303,590.485	7,844,746.340
Total	7,317,999.241	38,904,876.412	5,675,642.899	7,479,527.248	5,546,217.593	4,645,405.362	69,569,668.754

Kentucky Power Company

REQUEST

State whether Kentucky Power outsources coal handling or whether coal handling is performed by Kentucky Power employees, and explain how coal-handling costs are accounted for in the calculation of the FAC.

RESPONSE

Kentucky Power coal handling is performed by Kentucky Power employees, contract personnel, and AEP Service corporation employees. Coal handling costs are included in base rates and excluded from the FAC calculations.

WITNESS: John A Rogness

Kentucky Power Company

REQUEST

State whether all long-term fuel transportation contracts have been filed with the Commission. If any contracts have not been filed, provide a copy.

RESPONSE

All long-term fuel transportation contracts have been filed with the Commission.

WITNESS: John A. Rogness

Kentucky Power Company

REQUEST

For each generating station;

a. State how often coal-pile surveys are undertaken

b. Explain how any resulting adjustment affects fuel costs in the calculation of the FAC;

c. Provide the costs of performing a coal-pile survey at each of the generating stations and explain how the costs are accounted for; and

d. Provide a copy of all internal accounting policies related to coal-pile survey adjustments and the date the policies were last revised

RESPONSE

a. Coal Pile Surveys are typically done once or twice annually. For plants that blend coal there are two coal pile surveys conducted each year. Most other plants conduct annual survey adjustments except that a second survey will be performed within six months when the difference between the book inventory and the physical (surveyed) inventory varies by more than +/- two percent of the coal consumed.

Therefore, surveys are conducted twice annually at Mitchell. Big Sandy surveys are conducted at least annually.

b. Coal pile survey adjustments are treated as an increase/decrease to consumption in the month recorded and result in a correlating effect on the fuel costs included in the FAC calculations.

Note: During the review period, the adjustment following the Big Sandy survey in the fourth quarter of 2013 was valued at $1 in accordance with previous accounting practice. Please also refer to KPSC 1-33 for additional information regarding the required changes in Kentucky's survey accounting treatment after the Mitchell plant asset transfer.

c. The Big Sandy November 2013 and April 2014 coal pile survey costs were $7,166.53 and $8,334.23 respectively. The Mitchell February 2014 coal pile survey costs were $9,552.97. These costs are charged to FERC Account 1520000, coal handling.

d. Please see Attachment 1 to this response for a copy of Accounting Bulletin #4.

WITNESS: John A Rogness III

AEP®

Accounting Policy/Procedure

Policy/Procedure Title	Accounting for Coal Costs	Date	1/1/14

Purpose

This accounting policy / procedure memo serves to update and replace AEP Accounting Bulletin 4, "Accounting for Coal Costs." The detailed instructions that follow have been developed for the purpose of establishing System uniformity in the classification of the more significant items of coal cost among Account 151, Fuel Stock; Account 152, Fuel Stock Expenses Undistributed; Account 501, Fuel; and Account 502, Steam Expenses.

This Bulletin also outlines the physical inventory process and the procedures for recognizing coal inventory adjustments.

Fossil fuel inventories are generally carried at weighted average cost with the exception of AGR and TNC-EP which are carried at the lower of average cost or market. Coal mine inventories are also carried at the lower of cost or market.

This policy / procedure document may not be released to parties outside AEP without the approval of the Chief Accounting Officer.

Policy/Procedure Statement

I. ACCOUNT 151, FUEL STOCK-COAL

This account, as it applies to coal, shall include the invoice cost of coal, freight, switching, demurrage, barging, excise taxes, insurance, and other purchase and transportation related costs. Exclude from this account all costs of labor and other expenses of unloading coal at the generating plant site and handling in storage, as provided in "Account 152, Fuel Stock Expenses Undistributed."

Items:

1. Invoice price of coal, less any trade discounts.

2. Freight, switching, barging, demurrage and other transportation charges and related taxes.

3. Inventory adjustments to correct overages and shortages.

4. Excise taxes, purchasing agents' commissions, liability insurance on cargo and barge operations, other insurance and expenses directly related to the purchase and transportation of coal.

5. Tipple and dumping charges regarding transfer from railroad cars to barges and other transfer activities prior to delivery at the generating plant site.

6. Operating, maintenance and depreciation expenses and ad valorem taxes on utility-owned transportation equipment used to transport coal anywhere between the point of acquisition and the generating plant unloading point.

7. Lease or rental costs of transportation equipment used to transport coal anywhere between the point of acquisition and the generating plant unloading point.

II. ACCOUNT 152, FUEL STOCK EXPENSES UNDISTRIBUTED-COAL

This account, as it applies to coal, shall include the cost of labor and supplies used and expenses incurred in procuring coal, in unloading coal from the shipping medium at the generating plant site and in handling coal prior to use.

Amounts included herein shall be charged monthly to Account 501, Fuel, based on the product of the accumulated average handling costs per ton (as of the close of the current month) and the tons of coal consumed. The balance maintained in this account shall not exceed the expenses attributable to the inventory of fuel on hand (therefore, inventory adjustments to correct overages and shortages should include a proportionate share of the expenses included in Account 152, see Section V. C.)

Labor:

1. Procurement activities performed by AEP System personnel, including investigation of sources of coal supply and the negotiation of contracts.

2. Unloading coal shipments from rail cars, barges or trucks into storage.

3. Weighing and recording coal.

4. Fuel accounting activities performed by AEP System personnel, including the processing of invoices and related records for coal placed in stock would be included in Account 152.

5. Moving of coal in storage pile; e.g., movement for fire prevention purposes and transferring from one station to another.

6. Packing coal pile.

7. Checking moisture content of coal pile.

8. Controlling dust from coal in storage.

9. Cleaning coal bunkers separate from boiler-house structure to prevent or release jams.

10. Routine analysis of coal before being consumed.

11. Routine testing and calibrating of coal conveyor scales located outside of the boiler-house structure.

12. Handling coal from shipping medium and storage to the first bunker in the boiler-house structure.

13. Conducting a physical inventory of the coal pile, including vendor costs. (See Section V. B. for recordation of adjustments.)

Supplies and Expenses:

1. Expenses associated with procurement activities performed by AEP System personnel, including investigation of sources of coal supply and negotiation of contracts.

2. Oil for thawing coal in coal cars or barges at the plant site.

3. Rent of leased coal handling and storage equipment.

4. Transportation and other expenses in moving coal in storage and from plant to plant.

5. Stores expenses applicable to coal.

6. Tools, lubricants, fuel and miscellaneous supplies used in connection with analyzing coal, dust control, packing and inventorying the coal pile and operating coal handling equipment.

NOTES:

(A) Maintenance of fuel handling equipment located within the boiler plant shall be charged to Account 512.0, Maintenance of Boiler Plant.

(B) Fuel oil not used in the generation of electricity should be classified to account 152000, Fuel Stock Expenses Undistributed.

III. ACCOUNT 501, FUEL

This account, as it applies to coal, shall include the cost of coal used in the production of steam for the generation of electricity, including expenses in unloading coal from the shipping media and handling thereof up to the point where it enters the boiler-house structure.

Costs shall be charged to this account from Accounts 151, Fuel Stock, and 152, Fuel Stock Expenses Undistributed, as provided in Sections I. and II. above.

In addition, this account shall include, on a direct charge basis, the cost of labor, supplies used and expenses incurred for:

1. Preparing and maintaining coal records and reports of coal consumed.

2. Testing refuse ash and refuse to determine characteristics and properties (when related to disposal of residuals).

3. Consultants' fees and expenses applicable to fuel consumed.

4. Disposal expenses regarding cinders, fly ash and other residuals after they are accumulated at a generating plant site, less any sales proceeds derived from the disposal thereof.

5. Information services and usage charges in connection with monitoring of coal shipments en route and reporting of coal shipments received.

6. Other significant fuel related activities with review of AEPSC Accounting Policy and Research.

IV. ACCOUNT 502, STEAM EXPENSES

The cost (labor, supplies, and expenses) of the following activities shall be charged to Account 502, Steam Expenses:

1. Operating air pollution control equipment located outside the boiler plant, e.g., fly ash bins, silos and pump houses.

2. Operating water pollution control equipment in the ash disposal system, i.e., checking, adjusting, cleaning and lubricating motors and related equipment of the bottom ash pond reclaim water system.

3. Operating ash-handling equipment outside of the boiler plant. Testing refuse ash and refuse to determine characteristics and properties (when related to other than disposal of residuals).

4. Operating coal conveying, storage, weighing and processing equipment within the boiler plant.

V. COAL INVENTORY ADJUSTMENTS

A. Procedures for Determining the Amount of the Adjustment

1. Frequency of Inventories

a. An annual physical inventory of coal piles shall be conducted at each coal burning power plant. The results of this inventory shall be reported by each plant, using form 0955A-Coal Storage Inventory Report, in accordance with Circular Letter CI-O-CL-008 as developed by the Civil Engineering Lab. Civil Engineering will provide an updated copy of the coal pile inventory schedule to Accounting when changes are made. The schedule will include deadlines for Coal Pile Inventory (CPI) report distribution (density and volume of coal) and the 0955A report distribution (tons of coal). Accounting will review the deadlines and will follow up with the plants as necessary, if a report is not received on schedule. For surveys completed prior to a quarter-end, the 0955A report should be distributed no later than the first work day of the following month so adjustments can be recorded in the same quarter.

For surveys completed during the last week of a quarter-end month, whereby the completion of the CPI and 0955A reports by the first work day of the following month is not feasible, the reports should be completed as soon as possible and the results provided to Accounting immediately. Accounting will assess the materiality of the survey adjustment to determine if the books should be reopened to record the survey adjustment.

(i) As set out in Circular Letter CI-O-CL-008, if, as the result of a physical inventory, the difference between the book inventory and the physical inventory as a percent of the coal consumed is greater than the established tolerance, currently +/- 2%, an investigation will be conducted to determine the cause of the difference, a plan will be developed to correct the cause and an additional, special, physical inventory will be performed within six months to measure and record the results of the corrective action.

b. An annual physical inventory at Cook Coal Terminal will not be required as long as the coal pile has been physically depleted and adjustments made in accordance with Section V. B. 2. of this bulletin at least once every year.

2. Acceptance of the physical inventory

a. A coal pile inventory is considered technically acceptable if, after a careful review of the measurements and computations by the AEP Civil Engineering Lab and/or a competent third party, the measurements are deemed to have been taken in accordance with the instructions in circular letter CI-O-CL-008 and that no significant errors exist in the inventory computations.

b. If the results of the physical inventory are still deemed to be unacceptable by either the Plant Manager or the Regional Director of Fossil & Hydro Operations, an additional physical inventory shall be conducted as soon as possible.

3. Calculation of Adjustments

a. Based on an evaluation of the results of the annual or special physical inventory, adjustments will be made to the coal inventory accounts for differences between the physical inventory and the perpetual inventory records. Adjustments will be recorded as expeditiously as possible after receipt of the inventory report. Prior to being recorded, adjustments will be reviewed for mathematical accuracy by accounting and the variance explanation will be reviewed for reasonableness.

b. Inventory adjustments to be recorded for tonnage overages or shortages will be determined as follows:

(i) Corrections to the book tonnages resulting from any physical inventory will be recorded to the extent of 100 percent of the discrepancy between the physical inventory and the perpetual inventory records. (See NOTES.)

(ii) Before computation of the discrepancy from a physical inventory, the perpetual inventory records shall reflect any previous inventory adjustment.

(iii) Before computation of the discrepancy from a physical inventory, the perpetual inventory records shall reflect the passed through effect of a coal pile adjustment at the Cook Coal Terminal for plants receiving such coal, provided an inventory was required and performed at the Cook Coal Terminal.

NOTES:

(A) In cases of joint ownership of generating plants, a single method of adjusting tonnage must be used for the entire coal inventory regardless of ownership.

(B) At multiunit plants that feed different units from the same pile the amount of the adjustment shall be apportioned to each unit based on the coal consumed by each unit. The coal consumption data used to determine the ration between units shall be taken from the Fuel Data Reporting System (FDR). The reporting period for this calculation shall be from the close of business on the date of previous inventory to the close of business for the current inventory.

4. Records and Reports Generated from Physical Inventories

   a. The Materials Handling Section and the Civil Engineering Lab Section of the Civil & Mining Engineering Division shall maintain a database of coal pile inventory results.

   b. The data base of coal pile inventory results shall include the following statistics:
      (i) Percent Difference of Physical Inventory as compared to Book Inventory.
      (ii) Percent Difference of Physical Inventory as compared to Coal Consumed during the period between inventories.

   c. The data base of coal pile inventory results will be compiled as quickly as possible after receipt of 0955A reports and made available to plant managers and others.

5. Elimination of Coal in Inventory

   Periodically, a coal inventory may be physically depleted, particularly at the Cook Coal Terminal. Any perpetual inventory balance at that time (including any deficit) shall be adjusted to eliminate the book balance. Such an adjustment will be recorded in the month in which the physical inventory is depleted.

   At the time of physical depletion of the coal there may be unusable coal remaining in the coal yard. The depleted coal pile should be mapped to establish a revised base map of the coal yard for use in future inventories.

B. Recordation

   1. Generating Plants
      Account 151, Fuel Stock-Coal, and 152, Fuel Stock Expenses Undistributed-Coal, are to be charged (if the results of the physical inventory exceed the recorded amounts) or credited (if the results of the physical inventory are less than the

recorded amounts) with an appropriate offset to Operating Expense Account 501, Fuel.

Overages or shortages will be priced at the average unit cost per ton during the months that the adjustments are recorded.

Unusually large total company adjustments are to be promptly reported (before recordation) to the attention of AEPSC Accounting Policy and Research for consideration.

The Cardinal, Conesville, Oklaunion, Pirkey, and Flint Creek Plants maintain separate coal piles of different quality. As a result, System companies reflect a different fuel cost per ton from that of the non-associated owner companies.

2. Cook Coal Terminal

Adjustments will be prorated to the recipients of all AEP coal shipments from Cook Coal Terminal since the later of either the last coal inventory or the establishment of the present coal pile.

C. Example

Annual Inventory Results

Physical Inventory	625,000 tons
Perpetual Inventory	600,000
Overage	25,000
Adjustment	25,000

Average Unit Cost per ton:

Fuel Stock-Coal	\$34.579
Fuel Stock Expenses Undistributed –Coal	.23
Total	\$34.809

Entry

Account 151, Fuel Stock -Coal	\$864,475	
Account 152-Fuel Stock Expenses Undist. Coal	\$ 5,750	
Account 501, Fuel		\$870,225

To record, in accordance with AEP System Accounting Bulletin No. 4, the coal inventory overage disclosed by the Annual coal pile inventory at the _______ plant.

D. Coal Storage Inventory Reports

Copies of the completed form 0955A-Coal Storage Inventory Reports are to be sent to the AEPSC Internal Auditing Department, the Performance Engineering Division of the AEPSC Fossil Plant Operations Department, and other personnel as specified by the circular letter CI-O-CL-008.

Kentucky Power Company

REQUEST

Refer to Kentucky Power's "Standard Fuel Adjustment Clause Backup Filing" filed on April 15, 2014, for the expense month of February 2014. This filing shows a coal-pile survey adjustment of $457,588.53 for the Mitchell Station which resulted in an increase in fuel costs.

a. Provide the date the survey adjustment was undertaken.

b. Provide the date the previous survey adjustment was undertaken.

c. Explain why the physical inventory was not taken on the date the change in control of the Mitchell Station occurred.

d. Provide the total amount of the adjustment among all owners of the Mitchell Station and explain how the allocation of $457,588.53 to Kentucky Power was calculated.

e. In past filings, Kentucky Power assigned a cost of $1 to coal-pile survey adjustments. Explain the reason for the change and state whether this change is in compliance with the internal accounting policy regarding coal pile adjustments.

f. By month, for January through April 2014, provide the total kWh generated at the Mitchell Station along with the total kWh and percentage allocated to Kentucky Power. If the percentages are something other than 50 percent, and if the Kentucky Power's financial reports reflect 50 percent of the costs associated with Mitchell Station, both investment and operating (less fuel) and maintenance expenses, explain why it is appropriate for Kentucky Power's financial reports to reflect something other than 50 percent of the Mitchell generating station generation.

g. By month for the review period, provide the total kWh generated at the Rockport generating station along with the total kWh and percentage allocated to Kentucky Power.

RESPONSE

a. The Mitchell survey was conducted during the first quarter of 2014 for the survey period September 18, 2013 through February 5, 2014.

b. The previous Mitchell survey was conducted during the third quarter of 2013 for the survey period February 6, 2013 through September 18, 2013.

c. Prior to the change in control of Mitchell, the most current survey at Mitchell was completed during the third quarter of 2013. The per book records of Mitchell tons at the end of the December 2013 were considered accurate until the next scheduled survey. The subsequent survey in the first quarter of 2014, which included a period of time prior to the Mitchell transfer, was evaluated for appropriate proration between the owners. Please see subpart (d) below.

d. The total amount of the survey adjustment for Mitchell Plant was $2,331,384.29 for AEP Generation Resources (AEPGR) and $457,588.53 for Kentucky Power. The survey adjustment tons were prorated among the owners based on coal tons consumed over the survey period. For coal tons consumed at Mitchell Plant from 09/18/2013 through 12/31/2013, 100% was assigned to AEPGR. For coal tons consumed at Mitchell Plant from 01/01/2014 through 02/05/2014, survey adjustment tons were prorated among the owners based on the 2014 Net Take percentages provided by Generation Dispatch. The resulting total prorated survey tons assigned to the owners were valued at the available February 2014 weighted average cost of inventory. Please see Attachment 1 to this response for the calculation.

e. Since about 1980, KPCo has recorded coal pile survey adjustments for Big Sandy plant by reflecting the adjustment with 100% of the number of tons to be adjusted but adjusting the inventory dollars by $1. Under the FERC-approved Mitchell Plant Operating Agreement (operating agreement), that is attached to this response as Attachment 2, both of the Mitchell owners, KPCo and AEPGR, are required to have the same weighted average cost of inventory every month. Kentucky Power could not value its inventory adjustments at $1 and comply with the operating agreement. To be consistent with its accounting practices and because Kentucky Power could not use the $1 valuation methodology for the Mitchell plant, it was also determined that KPCo should no longer use the $1 valuation methodology for the Big Sandy plant.

The $1 method has the effect of adjusting the $/ton of inventory only and impact fuel expense (favorable or unfavorable) in the months to follow. The rationale for adjusting for 100% of the survey adjustment tons and dollars in the first month reported is that the adjustment is in fact a true-up of consumption. All other AEP plants adjust both the tons and dollars of coal inventory for the survey results when reported.

This change is in compliance with the internal accounting policy regarding coal pile adjustments formally adopted in August 2014 and effective January 1, 2014. Please see KPSC 1-32 Attachment 1 for a copy of the updated internal accounting policy.

f. Below is total kWh generated at Mitchell Plant and with the kWh and percentage allocated (dispatched) to Kentucky Power as provided by Generation Dispatch:

	Total Mitchell:	Kentucky Share:	Kentucky Percentage:
Jan 2014	703,641,000	359,029,500	51.025%
Feb 2014	600,780,000	301,325,000	50.156%
Mar 2014	859,384,000	430,697,000	50.117%
Apr 2014	745,902,000	368,914,000	49.459%

Section 6.1(c) of the Mitchell Operating Agreement (pages 7 & 8 of Attachment 2) states, "In each calendar month, KPCo's and AEPGR's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1(b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month." O&M (less fuel) would be different than 50 percent due to the variable O&M being based on the previous 60-month rolling average of net take (dispatch), which is not 50:50.

g. Please see Attachment 3 to this response.

WITNESS: John A Rogness III

KPCO/AEPGR
SURVEY OWNERSHIP RATIOS
MITCHELL PLANT

COAL

	TONS CONSUMED (a)		
MITCHELL	**KPCO**	**AEPGR/OPCo**	**TOTAL**
UNIT 1 TONS CONSUMED	69,407.66	288,707.34	358,115.00
UNIT 2 TONS CONSUMED	102,504.47	587,837.53	690,342.00
TOTAL PLANT	171,912.13	876,544.87	1,048,457.00
RATIO-UNIT 1	19.380%	80.620%	100.000%
RATIO-UNIT 2	14.850%	85.150%	100.000%
RATIO-TOTAL PLANT	16.397%	83.603%	100.000%

(a) Survey period 09/18/2013 - 02/05/2014 -- MWH's Prorated based on tons consumed over survey period
09/18/2013 thru 12/31/2013 > AEPGR assigned 100%
01/01/2014 thru 02/05/2014 > AEPGR & KPCo assigned respective Net Take %'s for the period

RATE SCHEDULE NO. 303

MITCHELL PLANT OPERATING AGREEMENT

KENTUCKY POWER COMPANY

AEP GENERATION RESOURCES INC.

And

AMERICAN ELECTRIC POWER SERVICE CORPORATION, AS AGENT

Tariff Submitter: **Kentucky Power Company**
FERC Program Name: **FERC FPA Electric Tariff**
Tariff Title: **KPCo Rate Schedules and Service Agreement Tariffs**
Tariff Proposed Effective Date: **01/01/2014**
Tariff Record Title: **Mitchell Plant Operating Agreement**
Option Code: **A**
Record Content Description: **Rate Schedule No. 303**

THIS MITCHELL PLANT OPERATING AGREEMENT ("Agreement"), dated January 1, 2014 is by and among Kentucky Power Company, a Kentucky corporation qualified as a foreign corporation in West Virginia ("KPCo") and AEP Generation Resources Inc., a Delaware corporation qualified as a foreign corporation in West Virginia ("AEPGR") (such two parties hereinafter sometimes referred to as the "Owners"); and American Electric Power Service Corporation ("Agent"), a New York corporation qualified as a foreign corporation in West Virginia. KPCo, AEPGR, and Agent may hereinafter be referred to as a "Party" or collectively as the "Parties".

WITNESSETH:

WHEREAS, KPCo and AEPGR have acquired an undivided ownership interest in the Mitchell Power Generation Facility consisting of two 800MW generating units and associated plant, equipment and real estate, located in Moundsville, West Virginia, (the "Mitchell Plant"); and

WHEREAS, KPCo now has an undivided 50% ownership interest in the Mitchell Plant and AEPGR now has an undivided 50% ownership interest in the Mitchell Plant; and

WHEREAS, the Owners desire that KPCo shall operate and maintain the Mitchell Plant in accordance with the provisions set forth herein; and

WHEREAS, the Owners are subsidiaries of American Electric Power Company, Inc., ("AEP") the parent company in an integrated public utility holding company system, and use the services of Agent, (an affiliated company engaged solely in the business of furnishing essential services to the Owners and to other affiliated companies), as outlined in the service agreements between Agent and KPCo and between Agent and AEPGR.

NOW THEREFORE, in consideration of the premises and for the purposes hereinabove recited, and in consideration of the mutual covenants hereinafter contained, the signatories agree as follows:

ARTICLE ONE

FUNCTIONS OF KPCO AND AGENT

1.1 KPCo shall operate and maintain the Mitchell Plant in accordance with good utility practice consistent with procedures employed by KPCo at its other generating stations, and in conformity with the terms and conditions of this Agreement.

1.2 KPCo shall keep all necessary books of record, books of account and memoranda of all transactions involving the Mitchell Plant, and shall make computations and allocations on behalf of the Owners, as required under this Agreement. The books of record, books of account and memoranda shall be kept in such manner as to conform, where so required, to the Uniform System of Accounts as prescribed by the Federal Energy Regulatory Commission ("FERC") for Public Utilities and Licensees ("Uniform System of Accounts"), and to the rules and regulations of other regulatory bodies having jurisdiction as they may from time to time be in effect.

1.3 The Owners shall establish such joint bank accounts as may from time to time be required or appropriate.

1.4 As soon as practicable after the end of the month, KPCo shall furnish to AEPGR a statement setting forth the dollar amounts associated with the operation and maintenance of the Mitchell Plant as allocated hereunder to KPCo and AEPGR for such month. The Owners shall, on a timely basis, deposit sufficient dollar amounts in the appropriate bank accounts to cover their respective allocations of such costs.

1.5 KPCo shall be responsible for the day to day operation and maintenance of the Mitchell Plant. KPCo shall obtain such materials, labor and other services as it considers necessary in connection with the performance of the functions to be performed by it hereunder from such sources or through such persons as it may designate.

1.6 Agent, as directed by the Operating Committee and consistent with Agent's service agreements with KPCo and AEPGR, shall provide services necessary for the safe and efficient operation and maintenance of the Mitchell Plant.

ARTICLE TWO

APPORTIONMENT OF CAPACITY AND ENERGY

2.1 The Total Net Capability of the Mitchell Plant at the Mitchell Unit 1 and Unit 2 low-voltage busses, after taking into account auxiliary load demand, is 1,560,000 kilowatts. The Owners may from time to time modify the Total Net Capability of the Mitchell Plant as they may mutually agree.

2.2 The Total Net Generation of the Mitchell Plant during a given period, as determined by the requirements of KPCo and AEPGR, shall mean the electrical output of the Mitchell Plant generators during such period, measured in kilowatt hours by suitable instruments, reduced by the energy used by auxiliaries for the Mitchell Unit 1 and Unit 2 during such period.

2.3 Except as set forth in Section 7.6 (including Section 7.6 Subsections), in any hour, KPCo and AEPGR shall share the minimum load responsibility of Mitchell Unit 1 and Unit 2 in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time. Each Owner shall independently dispatch its share of the generating capacity between minimum and full load.

2.4 In any hour during which the Mitchell Units are out of service, the energy used by the out-of-service Units' auxiliaries during such hour shall be provided by KPCo and AEPGR in respective amounts proportionate to their ownership interests in the Mitchell Plant at such time.

ARTICLE THREE

REPLACEMENTS, ADDITIONS, AND RETIREMENTS

3.1 KPCo shall from time to time make or cause to be made any additions to, replacements of, and retirements of capitalizable facilities associated with the Mitchell Plant in accordance with the approved annual budget.

3.2 The dollar amounts associated with any additions to, replacements of, or retirements of capitalizable facilities associated with the Mitchell Plant shall be allocated to KPCo and AEPGR in respective amounts proportionate to their ownership interests in the Mitchell Plant at the time such additions, replacements, or retirements are made.

ARTICLE FOUR

WORKING CAPITAL REQUIREMENTS

4.1 KPCo and AEPGR shall periodically mutually determine the amount of funds required for use as working capital in meeting payrolls and other expenses incurred in the operation and maintenance of the Mitchell Plant, and in buying materials and supplies (exclusive of fuel) for the Mitchell Plant.

4.2 KPCo and AEPGR shall from time to time provide their share of working capital requirements in respective amounts proportionate to their ownership interests at such time in the Mitchell Plant.

ARTICLE FIVE

INVESTMENT IN FUEL

5.1 KPCo and Agent shall establish and maintain reserves of coal in stock piles for the Mitchell Plant of such quality and in such quantities as the Operating Committee shall determine to be required to provide adequate fuel reserves against interruptions of normal fuel supply, provided each Owner, subject to the approval of the Operating Committee and subject to no adverse impact on the operation of the Mitchell Plant, will have the right, but not the obligation, to directly purchase coal, transportation and consumables for its ownership interest. For the purposes of this Agreement "consumables" shall be as defined in FERC account 502.

5.2 Except as provided in Section 5.1 for an Owner to elect to procure coal for its own interest, the Owners shall make such monthly investments in the common coal stock piles associated with the Mitchell Plant as are necessary to maintain the number of tons in such coal stock piles, after taking into account the coal consumption from the common coal stock piles by Mitchell Unit 1 and Unit 2 during such month.

5.3 At any time, KPCo's and AEPGR's respective shares of the investment in the common coal stock piles shall be proportionate to their ownership interests in the Mitchell Plant, unless an Owner elects to procure its own coal as provided in Section 5.1, in which case inventories will be separately maintained for accounting purposes.

5.4 Fuel oil and consumables charged to operation for the Mitchell Plant shall be owned and accounted for between the Owners in the same manner as coal.

ARTICLE SIX

APPORTIONMENT OF STATION COSTS

6.1 Except in the case where an Owner has elected to purchase coal for its own interest as provided for in Section 5.1 (in which case the allocation to the Owners of fuel expense shall be in accordance with procedures and processes approved by the Operating Committee), the allocation to the Owners of fuel expense associated with Mitchell Unit 1 and Unit 2 shall be determined by KPCo and Agent as follows:

(a) In any calendar month, the average unit cost of coal available for consumption from the Mitchell Plant common coal stock piles shall be determined based on the prior month's ending inventory dollar and ton balances plus current month receipts delivered to the Mitchell Plant common coal stock piles. Each Owner's average unit cost will be the same, and receipts and inventory available for consumption amounts will be allocated to each Owner based on monthly usage.

(b) The number of tons of coal consumed by the Mitchell Plant in each calendar month from the Mitchell Plant common coal stock piles shall be determined and shall be converted into a dollar amount equal to the product of (i) the average cost per ton of coal associated with the Mitchell Plant in the Mitchell Plant common coal stock pile at the close of such month, and (ii) the number of tons of coal consumed by the Mitchell Plant from the Mitchell Plant common coal stock piles during such month. Such dollar amount shall be credited to the Mitchell Plant fuel in stock pile and charged to Mitchell Plant fuel consumed.

(c) In each calendar month, KPCo's and AEPGR's respective shares of the Mitchell Plant fuel consumed expense as determined by the provisions of Section 6.1 (b) shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(d) Fuel oil reserves will be owned and accounted for in the same manner as coal stock piles, and fuel oil consumed will be allocated to the Owners in the same manner as coal consumed.

6.2 For purposes of this Agreement, KPCo's Assigned Capacity in the Mitchell Plant shall be equal to 50% of the Total Net Capability, and AEPGR's Assigned Capacity shall be equal to 50% of the Total Net Capability.

6.3 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant operations expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.4 For each calendar month, KPCo and Agent will, to the extent practicable, determine all Mitchell Plant maintenance expenses and associated overheads, as accounted for under the FERC Uniform System of Accounts.

6.5 In each calendar month, KPCo's and AEPGR's respective shares of operations and maintenance expenses associated with the Mitchell Plant, as determined in accordance with Sections 6.3 and 6.4, shall be allocated as follows:

(a) In each calendar month, KPCo's and AEPGR's respective shares of the Mitchell Plant steam expenses as recorded in FERC Account 502, and emission tons, with allowance expenses as recorded in FERC Account 509, shall be proportionate to each Owner's dispatch of the Mitchell Plant in such month.

(b) In each calendar month, the maintenance of boiler plant expenses as recorded in FERC Account 512, and maintenance of electric plant expenses as recorded in FERC Account 513, shall be directly assigned to Mitchell Unit 1 or Unit 2 or designated as a common expense attributable to both units. In each calendar month, KPCo's and AEPGR's respective shares of these expenses shall be proportionate to each Owner's dispatch of the applicable unit, or both units in the case of common expenses, over the previous sixty (60) calendar months. Dispatch is assumed to have been allocated fifty percent (50%) to each Owner for months that are prior to this Agreement.

(c) In each calendar month, KPCo's and AEPGR's respective shares of all other operations, maintenance, administrative and general expenses shall be proportionate to their respective ownership interests.

6.6 Each Owner shall bear the cost of all taxes attributable to its respective ownership interest in the Mitchell Plant.

ARTICLE SEVEN

OPERATING COMMITTEE AND OPERATIONS

7.1 By written notice to each other, the Owners and Agent each shall name one representative ("Operating Representative") and one alternate to act for it in matters pertaining to operating arrangements under this Agreement. Any Party may change its Operating Representative or alternate at any time by written notice to the other Parties. The Operating Representatives for the respective Parties, or their alternates, shall comprise the Operating Committee. All decisions, directives, or other actions by the Operating Committee must be by unanimous agreement of the Operating Representatives of the Owners. The Operating Representative of Agent, or of any third party that provides services in replacement of Agent, shall be free to express the views of Agent or such third party on any matter, but shall not have a vote on the Operating Committee. Except as otherwise provided in Sections 11.1, 11.2 and 11.3 with respect to a dispute referred to the Operating Committee by an Owner, the failure of the Owners' respective Operating Representatives to unanimously agree with respect to a matter pending before the Operating Committee shall not be considered to be a dispute that would be subject to resolution under Article Eleven.

7.2 The Operating Committee shall have the following responsibilities:

a) Review and approval of an annual budget and annual operating plan, including determination of the emission allowances required to be acquired by KPCo and AEPGR. If the Operating Committee fails to approve an annual budget, the approved annual budget from the previous year will continue to apply until such time as the new annual budget is approved.

b) Establishment and review of procedures and systems for dispatch, notification of dispatch, and unit commitment under this Agreement, including any commitment of Called Capacity pursuant to Section 7.6.2.

c) Establishment and monitoring of procedures for communication and coordination with respect to the Mitchell Plant capacity availability, fuel-firing options, and scheduling of outages for maintenance, repairs, equipment replacements, scheduled inspections, and other foreseeable cause of outages, as well as the return to availability following an unplanned outage.

d) Decisions on capital expenditures, including unit upgrades and re-powering.

e) Determinations as to changes in the unit capability and decisions on unit retirement.

f) Establishment and modification of billing procedures under this Agreement.

g) Approval of material contracts for fuel, transportation or consumable supply. Establishment of specification of fuels, oversight of fuel inspection and certification procedures, management of fuel inventories, and allocation of rights under fuel supply, transportation and consumable contracts. Establishment of an Owner's procurement rights and procedures if the Owner elects to purchase coal, transportation or consumables for its own interest.

h) Establishment of, termination of, and approval of any change or amendment to the operating arrangements between KPCo and Agent or any replacement third party with respect to the Mitchell Plant generating units; provided, however, that Agent or any replacement third party shall participate in discussions pursuant to this subsection 7.2.h only if and to the extent requested to do so by both Owners.

i) Review and approval of plans and procedures designed to ensure compliance with any environmental law, regulation, ordinance or permit, including procedures for allocating and using emission allowances or for any programs that permit averaging at more than one unit for compliance.

j) Other duties as assigned by agreement of the Owners.

7.3 The Operating Committee shall meet at least annually, and at such other times as any Party may reasonably request.

7.4 The Parties shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties, and to supplement or correct such information on a timely basis.

7.5 The Owners will each make an initial unit commitment one business day ahead of real-time dispatch.

7.6 Application of this Section 7.6 (including subsections) is subject to (i) the receipt of any necessary regulatory approvals or waivers expressly granted for this Section 7.6; and (ii) the Operating Committee establishing and approving procedures and systems for dispatch. As used in this Section and subsections of this Section, the terms "Party" or "Parties" refers only to KPCo and AEPGR, or both of them, as the case may be.

7.6.1 If Mitchell Unit 1 or Unit 2 is designated to be committed by both Parties, such unit will be brought on line or kept on line. If neither Party designates Mitchell Unit 1 or Unit 2 to be committed, such unit will remain off line or to be taken offline.

7.6.2 When a Mitchell Unit is designated to be committed by one Party, but designated not to be committed by the other Party, the unit will be brought on line or kept on line if the Party designating the unit for commitment undertakes to pay any applicable start-up costs for the unit, as well as any applicable minimum running costs for the unit thereafter, in which event the unit shall be brought on line or kept on line, as the case may be. The Party so designating the unit to be committed shall have the right to schedule and dispatch up to all of the Available Capacity of the unit. Available

Capacity means that portion of the Owners' aggregate Assigned Capacity that is currently capable of being dispatched. The Party exercising this right shall be referred to as the "Calling Party," and the capacity called by that Party in excess of its Assigned Capacity Percentage of the Available Capacity of that unit shall be referred to as its "Called Capacity." The other Party shall be referred to as the "Non-Calling Party". The Calling Party shall provide reasonable notice to the Non-Calling Party of its call, including any start-up or shut-down time for the Unit. For purposes of this Agreement, KPCo's Assigned Capacity Percentage shall be 50%, and AEPGR's Assigned Capacity Percentage shall be 50%.

7.6.3 The Non-Calling Party can reclaim any Called Capacity attributable to its Assigned Capacity share by giving the Calling Party notice equal to the normal cold start-up time for the unit. At the end of the notice period, the Non-Calling Party shall have the right to schedule and dispatch the recalled capacity. At that point, the Non-Calling Party shall resume its responsibility for its share of any applicable start-up costs for the unit and prospectively shall bear its responsibility for the costs associated with its Assigned Capacity from the unit.

7.6.4 If any capacity remains available but is not dispatched from a Party's Available Capacity committed as a result of the initial unit commitment, the other Party may only schedule and dispatch such capacity pursuant to agreement with the non-dispatching Party.

7.7 KPCo and AEPGR shall be individually responsible for any fees charged by FERC on the basis of the sales or transmission by each of capacity or energy at wholesale in interstate commerce.

7.8 Emission Allowances. To the extent such assignment has not previously occurred, on or before the effective date of this Agreement, KPCo and Agent will assign to AEPGR a pro rata share of the remaining Emission Allowances for each vintage year of Emission Allowances, issued by the U.S. Environmental Protection Agency ("USEPA") pursuant to Title IV of the Clean Air Act Amendments of 1990 and any regulations thereunder, and any other emission allowance trading program created under the Clean Air Act and administered by USEPA or the State of West Virginia, including but not limited to the Clean Air Interstate Rule 40 CFR Parts 96 and 97, and any amendments thereto ("Emission Allowances"), that it has received from the Administrator of USEPA or the State of West Virginia with respect to the Mitchell Plant in the past and has not expended as of the date of assignment. In each case, the number of such Emission Allowances to be assigned by KPCo to AEPGR will be determined by multiplying AEPGR's Assigned Capacity Percentage, as specified in Section 7.6.2, by the total of such Emission Allowances that KPCo or Agent has received or purchased for the Mitchell Plant and has not expended as of the date of assignment rounded to the nearest whole number. Emission Allowances received by KPCo with respect to the Mitchell Plant will be shared by the Owners in accordance with the Assigned Capacity Percentage of each of them. To the extent that additional Emission Allowances are required for operation of the Mitchell Plant, KPCo and AEPGR will each be responsible for acquiring sufficient Emission

Allowances to satisfy the Emission Allowances required because of its dispatch of energy from the Mitchell Plant, and the Emission Allowances required to satisfy the Emission Allowance surrender obligations attributable to the Mitchell Plant imposed under the Consent Decree between USEPA and Ohio Power Company entered on December 10, 2007, in Civil Action No. C2-99-1182 and consolidated cases by the U.S. District Court in the Southern District of Ohio. On or before January 10 of each year, Agent shall determine and notify KPCo and AEPGR of the number of additional annual Emission Allowances consumed by each of them through December 31 of the previous year, and KPCo and AEPGR shall each transfer into the Mitchell Plant U.S. EPA Allowance Transfer System account that number of Emission Allowances with a small compliance margin by January 31 of that year. For seasonal Emission Allowance programs, Agent shall determine and notify KPCo and AEPGR of the number of additional seasonal Emission Allowances consumed by each of them during the applicable compliance period by the 10th day of the first month following the end of the compliance period, and KPCo and AEPGR shall each transfer into the appropriate Mitchell Plant U.S. EPA Allowance Transfer System Account that number of Emission Allowances with a small compliance margin by the last day of the first month following the end of the compliance period. In the event that KPCo or AEPGR fails to surrender the required number of Emission Allowances by January 31 or the last day of the first month following any seasonal compliance period, Agent shall purchase the required number of Emission Allowances, and KPCo or AEPGR, as the case may be, shall reimburse Agent for such purchases, with interest at the Federal Funds Rate (as published by the Board of

Governors of the Federal Reserve System as from time to time in effect) running from the date of such purchases to the date of payment. The Operating Committee will develop procedures to be implemented after the end of each calendar year to account for the Emission Allowances required by the use of the Mitchell Plant by KPCo and AEPGR and to correct any imbalance between Emission Allowances supplied and Emission Allowances used through the end of the preceding year by settlement or payment.

7.9 Capital repairs and improvements to the Mitchell Plant will be determined by the Operating Committee pursuant to the annual budgeting process set forth in Section 7.10. Expenditures that the Operating Committee determines have been or will be incurred exclusively for one Owner shall be assigned exclusively to that Owner.

7.10 At least 90 days before the start of each operating year, KPCo and Agent shall submit to the Operating Committee a proposed annual budget with respect to the Mitchell Plant, a proposed annual operating plan, and an estimate and schedule of costs to be incurred for major maintenance or replacement items during the next six-year period. The annual budget shall be presented on a month-by-month basis for each month during the next operating year, and shall include an operating budget, a capital budget, an estimate of the cost of any major repairs that are anticipated will occur during such operating year with respect to the Mitchell Plant, and an itemized estimate of all projected non-fuel variable operating expenses relating to the operation of the Mitchell Plant during that operating year. The members of the Operating Committee will meet and work in good faith to agree upon the final annual budget and final annual operating plan. Once approved, the annual budget and annual operating plan shall remain in effect throughout the applicable operating year, subject to such changes, revisions, amendments, and updating as the Operating Committee may determine.

ARTICLE EIGHT

EFFECTIVE DATE AND TERM

8.1 Subject to FERC approval or acceptance for filing, the effective date of this Agreement shall be January 1, 2014.

8.2 Subject to FERC approval or acceptance, if necessary, this Agreement shall remain in force until such time as (i) KPCo or AEPGR has divested itself of all or any portion of its ownership interest in the Mitchell Plant, other than assignment or other transfer of such ownership interests to another AEP affiliate; or (ii) either KPCo or AEPGR is no longer a direct or indirect wholly owned subsidiary of AEP; or (iii) KPCo and AEPGR may mutually agree to terminate this Agreement.

ARTICLE NINE

GENERAL

9.1 This Agreement shall inure to the benefit of and be binding upon the signatories hereto and their respective successors and assigns, but this Agreement may not be assigned by any signatory without the written consent of the others, which consent shall not be unreasonably withheld.

9.2 This Agreement is subject to the regulatory authority of any State or Federal agency having jurisdiction.

9.3 The interpretation and performance of this Agreement shall be in accordance with the laws of the State of Ohio, excluding conflict of laws principles that would require the application of the laws of a different jurisdiction.

9.4 This Agreement supercedes all previous representations, understandings, negotiations, and agreements, either written or oral between the signatories or their representatives with respect to operation of the Mitchell Plant, and constitutes the entire agreement of the signatories with respect to the operation of the Plant. Notwithstanding the foregoing, this Agreement does not supercede any previous agreements among any of the signatories allocating or transferring rights to capacity and associated energy, or ownership, of the Mitchell Plant.

9.5 Each party shall designate in writing a representative to receive any and all notices required under this Agreement. Notices shall be in writing and shall be given to the representative designated to receive them, either by personal delivery, certified mail, facsimile, e-mail or any similar means, properly addressed to such representative at the address specified below:

KENTUCKY POWER COMPANY
Gregory G. Pauley
President & COO

Attn:

Phone: (502) 696-7007

Facsimile:(502) 696-7006

Email: ggpauley@aep.com

AEP GENERATION RESOURCES INC.
Charles E. Zebula
President

Attn:

Phone: (614) 716-2800

Facsimile: (614) 716-1404

Email: cezebula@aepes.com

AMERICAN ELECTRIC POWER SERVICE CORPORATION
Mark C. McCullough
Executive Vice President – Generation

Attn:

Phone: (614) 716-2400

Facsimile: (614) 716-1331

Email: mcmccullough@aep.com

All notices shall be effective upon receipt, or upon such later date following receipt as set forth in the notice. Any Party may, by written notice to the other Parties, change the representative or the address to which such notices are to be sent.

ARTICLE TEN

LIMITATION OF LIABILITY

10.1 Notwithstanding anything in this Agreement to the contrary, neither of the Owners or Agent shall be liable under this Agreement for special, consequential, indirect, punitive or exemplary damages, or for lost profits or business interruption damages, whether arising by statute, in tort or contract or otherwise.

ARTICLE ELEVEN

DISPUTE RESOLUTION

11.1 If either Owner believes that a dispute has arisen as to the meaning or application of this Agreement, it shall present that matter to the Operating Committee in writing, and shall provide a copy of that writing to the other Owner.

11.2 If the Operating Committee is unable to reach agreement on a dispute submitted to the Operating Committee pursuant to Section 11.1within thirty (30) days after the dispute is presented to it, the matter shall be referred to the chief operating officers of the Owners for resolution in the manner that such individuals shall agree is appropriate; provided, however, that either Owner involved in the dispute may invoke the arbitration provisions set forth in Section 11.3 at any time after the end of the thirty (30) day period provided for the Operating Committee to reach agreement if the Operating Committee has not reached agreement.

11.3 If the Owners are unable to resolve a dispute through the Operating Committee within thirty (30) days after the dispute is presented to the Operating Committee pursuant to Section 11.1, or through reference of the matter to the chief operating officers of the Owners pursuant to Section 11.2, either Owner may commence arbitration proceedings by providing written notice to the other Owner, detailing the nature of the dispute, designating the issue(s) to be arbitrated, identifying the provisions of this Agreement under which the dispute arose, and setting forth such Owner's proposed resolution of such dispute.

11.3.1 Within ten (10) days of the date of the notice of arbitration, a representative of each Owner shall meet for the purpose of selecting an arbitrator. If the Owners' representatives are unable to agree on an arbitrator within fifteen (15) days of the date of the notice of arbitration, then an arbitrator shall be selected in accordance with the procedures of the American Arbitration Association ("AAA"). Whether the arbitrator is selected by the Owners' representatives or in accordance with the procedures of the AAA, the arbitrator shall have the qualifications and experience in the occupation, profession, or discipline relevant to the subject matter of the dispute.

11.3.2 Any arbitration proceeding shall be subject to the Federal Arbitration Act, 9 U.S.C. §§ 1 *et seq.* (1994), as it may be amended, or any successor enactment thereto, and shall be conducted in accordance with the commercial arbitration rules of the AAA in effect on the date of the notice to the extent not inconsistent with the provisions of this Article.

11.3.3 The arbitrator shall be bound by the provisions of this Agreement where applicable, and shall have no authority to modify any terms and conditions of this Agreement in any manner. The arbitrator shall render a decision resolving the dispute in an equitable manner, and may determine that monetary damages are due to an Owner or may issue a directive that an Owner take certain actions or refrain from taking certain actions, but shall not be authorized to order any other form of relief; provided, however, that nothing in this Article shall preclude the arbitrator from rendering a decision that adopts the resolution of the dispute proposed by an Owner. Unless otherwise agreed to by the Owners, the arbitrator shall render a decision within one hundred twenty (120) days of appointment, and shall notify the Owners in writing of such decision and the reasons supporting such decision. The decision of the arbitrator shall be final and binding upon the Owners, and any award may be enforced in any court of competent jurisdiction.

11.3.4 The fees and expenses of the arbitrator shall be shared equally by the Owners, unless the arbitrator specifies a different allocation. All other expenses and costs of the arbitration proceeding shall be the responsibility of the Owner incurring such expenses and costs.

11.3.5 Unless otherwise agreed by the Owners, any arbitration proceedings shall be conducted in Columbus, Ohio.

11.3.6 Except as provided in this Article, the existence, contents, or results of any arbitration proceeding under this Article may not be disclosed without the prior written consent of the Owners, provided, however, that either Owner may make disclosures as may be required to fulfill regulatory obligations to any agencies having jurisdiction, and may inform its lenders, affiliates, auditors, and insurers, as necessary, under pledge of confidentiality, and may consult with expert consultants as required in connection with an arbitration proceeding under pledge of confidentiality.

11.3.7 Nothing in this Agreement shall be construed to preclude either Owner from filing a petition or complaint with FERC with respect to any claim over which FERC has jurisdiction. In such case, the other Owner may request that FERC reject the petition or complaint or otherwise decline to exercise its jurisdiction. If FERC declines to act with respect to all or part of a claim, the portion of the claim not so accepted by FERC may be resolved through arbitration, as provided in this Article. To the extent that FERC asserts or accepts jurisdiction over all or part of a claim, the decisions, findings of fact, or orders of FERC shall be final and binding, subject to judicial review under the Federal Power Act, 16 U.S.C. § 791a *et seq.*, as amended from time to time, and any arbitration proceedings that may have commenced prior to the assertion or acceptance of jurisdiction by FERC shall be stayed, pending the outcome of the FERC proceedings. The arbitrator shall have no authority to modify, and shall be conclusively bound by, any decisions, findings of fact, or orders of FERC; provided, however, that to the extent that any decisions, findings of fact, or orders of FERC do not provide a final or complete remedy to an Owner seeking relief, such Owner may proceed to arbitration under this Article to secure such a remedy, subject to any FERC decisions, findings, or orders.

11.4 The procedures set forth in this Article shall be the exclusive means for resolving disputes arising under this Agreement and shall survive this Agreement to the extent necessary to resolve any disputes pertaining to this Agreement. Except as provided in Sections 11.3 and 11.3.7, neither Owner shall have the right to bring any dispute for resolution before a court, agency, or other entity having jurisdiction over this Agreement, unless both Owners agree in writing to such procedure.

11.5 To the extent that a dispute involves the actions, inactions or responsibilities of Agent under this Agreement, the provisions of this Article shall be applicable to such dispute. For such purposes, Agent shall be treated as an Owner in applying the provisions of this Article.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By:______________________________
Gregory G. Pauley

Title: President & COO

AEP GENERATION RESOURCES INC.

By: Charles E. Zebula
Charles E. Zebula

Title: President

AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: [signature]
Mark C. McCullough

Title: Executive Vice President - Generation

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their officers thereunto duly authorized as of the date first above written.

KENTUCKY POWER COMPANY

By: Gregory G. Pauley

Title: President & COO

AEP GENERATION RESOURCES INC.

By: Charles E. Zebula

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AMERICAN ELECTRIC POWER SERVICE CORPORATION

By: Mark C. McCullough

Title: Executive Vice President - Generation

Rockport
KWH Generated
KYPCO Case No. 2014-00225 -- KPSC 1-33 (g)

											Kentucky Power Share	
			(A)			(B)					(A) * 30%	(B) * 30%
	Rockport - Unit 1			Rockport - Unit 2			Rockport Total				RK Unit 1	RK Unit 2
	Total	I&M	AEG	Total	I&M	AEG	Total	I&M	AEG	Total	KYP	KYP
Nov-2013	759,020,000	379,510,000	379,510,000	842,660,000	421,330,000	421,330,000	1,601,680,000	800,840,000	800,840,000	240,252,000	113,853,000	126,399,000
Dec-2013	919,400,000	459,700,000	459,700,000	900,480,000	450,240,000	450,240,000	1,819,880,000	909,940,000	909,940,000	272,982,000	137,910,000	135,072,000
Jan-2014	901,606,667	450,803,333	450,803,333	857,820,000	428,910,000	428,910,000	1,759,426,667	879,713,333	879,713,333	263,914,000	135,241,000	128,673,000
Feb-2014	631,640,000	315,820,000	315,820,000	634,933,333	317,466,667	317,466,667	1,266,573,333	633,286,667	633,286,667	189,986,000	94,746,000	95,240,000
Mar-2014	958,666,667	479,333,333	479,333,333	924,193,333	462,096,667	462,096,667	1,882,860,000	941,430,000	941,430,000	282,429,000	143,800,000	138,629,000
Apr-2014	732,920,000	366,460,000	366,460,000	600,160,000	300,080,000	300,080,000	1,333,080,000	666,540,000	666,540,000	199,962,000	109,938,000	90,024,000
Total	**4,903,253,333**	**2,451,626,667**	**2,451,626,667**	**4,760,246,667**	**2,380,123,333**	**2,380,123,333**	**9,663,500,000**	**4,831,750,000**	**4,831,750,000**	**1,449,525,000**	**735,488,000**	**714,037,000**