COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED

FEB 20 2013

PUBLIC SERVICE
COMMISSION

IN THE MATTER OF:

THE APPLICATION OF KENTUCKY POWER COMPANY FOR: (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; 5) FOR ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2012-00578

KENTUCKY POWER COMPANY RESPONSES TO

COMMISSION STAFF'S FIRST SET OF DATA REQUESTS

February 20. 2013

VERIFICATION

The undersigned, Mark A. Becker, being duly sworn, deposes and says he is the Manager, Resource Planning for American Electric Power Company that he has personal knowledge of the matters set forth in the foregoing 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

Mark A. Becker

Mark A. Becker

STATE OF OKLAHOMA	)	
	)	CASE NO. 2012-00578
COUNTY OF TULSA	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Mark A. Becker, this the 14 day of February, 2013.

Angela Brown

Notary Public

ANGELA BROWN
Notary Public in and for
STATE OF OKLAHOMA
Commission # 02003536
Expires: February 27, 2014

My Commission Expires: 2-27-14

VERIFICATION

The undersigned, Karl R. Bletzacker, being duly sworn, deposes and says he is Director, Fundamental Analysis 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.

Karl R Bletzacker

Karl R. Bletzacker

STATE OF OHIO	)	
	)	CASE NO. 2012-00578
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 19 day of February 2013.

NOTARY PUBLIC STATE OF OHIO

Holly M. Charles
Notary Public-State of Ohio
My Commission Expires
March 7, 2016

Holly M. Charles

Notary Public

My Commission Expires: March 7, 2016

VERIFICATION

The undersigned, Jeffery D. LaFleur, being duly sworn, deposes and says he is Vice President Generating Assets APCO/KY, 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

Jeffery D. LaFleur

JEFFERY D. LAFLEUR

STATE OF WEST VIRGINIA)
) Case No. 2012-00578
COUNTY OF KANAWHA)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jeffery D. LaFleur, this the 19 day of February 2013.

Dorothy E. Philyaw

Notary Public

OFFICIAL SEAL
STATE OF WEST VIRGINIA
NOTARY PUBLIC
DOROTHY E. PHILYAW
APPALACHIAN POWER
PO BOX 1986
CHARLESTON, WV 25327-1986
My commission expires October 2, 2019

My Commission Expires: October 2, 2019

VERIFICATION

The undersigned, Karl A. McDermott, being duly sworn, deposes and says he is the Special Consultant with NERA that he has personal knowledge of the matters set forth in the forgoing responses for which he/she is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Karl A. McDermott

Karl A. McDermott

STATE OF ILLINOIS)
) CASE NO. 2012-00578
COUNTY OF CHAMPAIGN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl A. McDermott, this the 16th day of February 2013.

"OFFICIAL SEAL"
BRADLEY M. KRALL
Notary Public, State of Illinois
My commission expires 01/04/15

Notary Public

My Commission Expires: 01/04/15

VERIFICATION

The undersigned, John M. McManus, being duly sworn, deposes and says he is Vice President Environmental Services 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

John M. McManus

John M. McManus

STATE OF OHIO)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 11 day of February 2013.

Janet White

Notary Public

My Commission Expires: JANET L. WHITE Notary Public, State of Ohio My Commission Expires 09-09-2013

VERIFICATION

The undersigned, Gregory G. Pauley, being duly sworn, deposes and says he is the President and Chief Operating Officer 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/her information, knowledge and belief

Greg G Pauley

Gregory G. Pauley

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory G. Pauley, this the 11th day of February, 2013.

Judy K Rasquist 481393

Notary Public

My Commission Expires: January 23, 2017

VERIFICATION

The undersigned, Scott C. Weaver, being duly sworn, deposes and says he is Managing Director Resource Planning and Operation Analysis 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

Scott C. Weaver

STATE OF OHIO)
) CASE NO. 2012-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver, this the 15th day of February 2013.

Notary Public

NOTARIAL SEAL
STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

My Commission Expires: October 1st, 2016

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. 2012-00578
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 11th day of February, 2013.

Judy K Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

Kentucky Power Company

REQUEST

Refer to paragraph 1 of Kentucky Power's verified application ("Application"), where it states, "[A]t this crossroad, and as promised earlier this year when Kentucky Power withdrew its application to retrofit Big Sandy Unit 2, the Company has conducted in-depth analysis of reasonable portfolio alternatives to determine the best path to ensure adequate and reliable capacity for its customers." Provide in electronic format, with formulas intact and unprotected, along with the date the analysis was performed, copies of all in-depth analyses performed to determine the best path to ensure adequate and reliable capacity for Kentucky Power's customers.

RESPONSE

Please see KPSC 1-1.zip on the enclosed CD for the response.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to paragraph 11 of the Application, where it states, "[T[he net book value of the fifty percent interest as of December 31, 2011 was $519 million and presently is forecasted to be approximately $535 million at the time of closing." Provide the following:

a. The projected investments, along with the estimated in service date of the investments, which will cause the net book value to increase from $519 million as of December 31, 2011 to the estimated $536 million as of the anticipated closing date of December 31, 2013;

b. The December 31, 2012 allowance inventory and the associated cost for the Mitchell and Big Sandy Plants;

c. An explanation, by plant, of how the Mitchell and Big Sandy Plants' allowance inventory and the associated costs are to be accounted for as of December 31, 2013, the expected date of the Transfer and Assumption Transaction; and

d. The net book value of the undivided 50 percent interest of the Mitchell generating station as of December 31, 2012, including the book value of the transferred assets and the book value of the assumed liabilities as of December 31, 2012.

RESPONSE

a. Please see KPSC Staff 1-2 Attachment 1 for details on the capital spending forecast for 2012 and 2013. The majority of the projects listed in the attachment will go in service during 2012 and 2013.

   Please see RKW-Exhibit 3 of Company witness Wohnhas' testimony for a reconciliation from $519 million to $536 million. This exhibit starts with the net book value as of 12/31/11 and then shows account balances that change over the 2012/13 time period. The primarily driver of the net book value increase is an increase in utility plant ($79 million) which is offset by an increase in accumulated depreciation expense ($63 million).

b. The December 31, 2012 allowance inventory and associated costs for one-half of Mitchell Plant allowances and Big Sandy allowances are provided below.

Approximate Values at
12/31/2012
(in millions)

Plant	Quantity	$ Value
Mitchell	0.630	$ 3.733
Big Sandy	0.816	$ 10.101

c. The allowance inventory and associated costs of Mitchell will be transferred at cost and recorded in account 158 as of December 31, 2013, which is the expected date of the transfer. The transfer of the 50% interest in Mitchell Plant allowances has no effect on the quantity and amount of allowances related to Big Sandy which continue to be recorded at cost in account 158.

d. The value of the 50% interest Mitchell Generating Station including the value of transferred assets and assumed liabilities as of December 31, 2012 is $538 million.

WITNESS: Ranie K Wohnhas

Mitchell Plant Estimated 2012 Capital Expense			
Actuals through August and 2012 Control Budget amounts for Sept-December			
Included in Asset Transfer Analysis 12-31-13 NBV Forecast			
Dollars in Thousands			
Mitchell Unit Number	Project	2012 Total - 100% of Mitchell	2012 Total - 50% of Mitchell
Mitchell Plant Unit 1	000020312 ML U1 Ash WWT System	572	286
	000021257 ML U1 ESP Upgrades	831	415
	ARCFLA181 Arc Flash Protection Swi OPCo	7	3
	FHNERC181 FHG NERC PPB OPCO	2	1
	GWSCB Cap Blkt - Prod Plant Blnkt	(83)	(42)
	KML11EP05 KML E POWER CABLE REPLACEMENT	0	0
	KML11EP06 KML E VALVE REPLACEMENT 6 IN G	(1)	(0)
	KML11EP08 ELECTRICAL #1	2	1
	KML11EP09 KML E AIR COMPRESSOR RPL	16	8
	KML11EP10 ELECTRICAL #3	29	14
	KML11EP13 KM2 NORTH TRAVELING SCREEN RPL	1	0
	KML11EP14 KML E MISC ELECTRICAL PROCESS	3	2
	KML11EP50 ML1 PRECIPITATOR LIGHTING	(15)	(7)
	KML11EP52 ML1 PRECIPITATOR TEMP POWER	(2)	(1)
	KML11SP07 SP #1	0	0
	KML11SP09 SP#3	0	0
	KML12EC01 ML PURCHASE BFP	335	168
	KML12EP01 KML E MOTORS GREATER THAN 50 H	4	2
	KML12EP03 KML E PUMP REPLACEMENT DR 50 H	74	37
	KML12EP06 KML E VALVE REPLACEMENT 6 IN G	2	1
	KML12EP07 KML E CIRCUIT BREAKER REPLACEM	4	2
	KML12EP26 KML E WORLD CLASS CHEMISTRY	16	8
	KML12EP55 KML E HVAC REPLACE	24	12
	KML12EP56 KML MISC ELECTRICAL PROCESS IT	29	15
	KML12MP01 KML MH COAL CHUTE REPLACEMENT	18	9
	KML12SP02 ML0 S PULVERIZER REBUILD CAP	30	15
	KML12SP04 ML1 S PULVERIZER GEARBOX #12	36	18
	KML12SP05 ML1 S PULV GEARBOX RPL 13	103	51
	KML12SP06 ML0 S PRECIPITATOR LINE GATE V	6	3
	KML12SP07 ML1 S UPPER BOILER VENT FAN RP	18	9
	KML12SP08 KML S INSTRUMENTATION RPL	3	2
	KML12SP11 KML S STEAM PROCESS	15	8
	ML0VP1201 ML NON OUTAGE PPB FGD	0	0
	ML113EP50 ML1 E TURBINE EBOP MOTOR	3	2
	ML11CSP01 ML PURCHASE CAP SPARE ID FAN	1	1
	ML11VPN01 ML NON OUTAGE PPB FGD	(32)	(16)
	ML1E11C06 ML 1 E GEN RETAINING RINGS INS	47	23
	ML1EP1104 ML1 E CONTROLS RECORDERS GAUGE	4	2
	ML1EP1201 ML1 E CONTROL POWER CABLE RECO	38	19
	ML1EP1210 ML1 E WESTRONIC SMARTMUX RPL	54	27
	ML1MP1301 ML1 MH VAC PIPING CH	73	37
	ML1NP1201 ML1 MISC PPB PROJECT	35	17
	ML1SP1201 ML1 S PREC EJ RPL	593	296
	ML1SP1202 ML1 S CLINKER GRINDER REPLACE	50	25
	ML1VC1101 ML1 FGD ABSORBER COATING	0	0
	ML1VC1201 ML1 CATALYST REPLACE 1ST LAYER	1,753	876
	ML1VP1102 ML1 V INSTALL AR PP DISCHARGE	(549)	(275)
	ML1VP1203 ML1 V INSTALL AR PP DISCHARGE	810	405
	ML2EP1216 ML2 E CLEAN UP SYSTEM RESIN RP	37	19
Mitchell Plant Unit 1 Total		4,996	2,498

Mitchell Plant Estimated 2012 Capital Expense			
Actuals through August and 2012 Control Budget amounts for Sept-December			
Included in Asset Transfer Analysis 12-31-13 NBV Forecast			
Dollars in Thousands			
Mitchell Unit Number	Project	2012 Total - 100% of Mitchell	2012 Total - 50% of Mitchell
Mitchell Plant Unit 0	*000019681 ML Hg Perm In-Pond Treatment*	3	1
	000019836 ML U1&2 Dry Fly Ash Conversion	27,667	13,834
	ARCFLA181 Arc Flash Protection Swi OPCo	9	4
	FGCEMS181 FHG CEMS DAHS Upgrade OPCo	3	2
	FHSECU181 FH Pysical Security OPCo	0	0
	GWSCB Cap Blkt - Prod Plant Blnkt	550	275
	ITGEN0388 NRX ASSET HUB - OHIO PWR	92	46
	KML11EP08 ELECTRICAL #1	0	0
	KML11EP10 ELECTRICAL #3	11	5
	KML11EP11 KML E ROOF REPLACEMENT	1	1
	KML11EP12 KM2 E HP EXCITER REDUCTION GEA	4	2
	KML11EP14 KML E MISC ELECTRICAL PROCESS	39	20
	KML11EP54 ML0 COAL HANDLING SPARE TRANS	8	4
	KML11MP05 MH #3	(25)	(13)
	KML11MP07 ML0 NEW GUARD BUILDING	(9)	(4)
	KML11MP08 ML MH COAL CRACKER REPLACEMENT	40	20
	KML11MP25 ML0 TRACK SCALE REPLACEMENT	1	0
	KML11MP27 ML FUEL OIL FURNANCE REPLACE	4	2
	KML11NP02 KML NP INSTALL CAP SPARE PARTS	3	2
	KML11NP03 KML NP PURCHASE PLANT TOOLS	12	6
	KML11NP04 KML NP PURCHASE PDM TOOLING	1	0
	KML12EC02 ML E BARGE UNLOADER CONTROLS	406	203
	KML12EP01 KML E MOTORS GREATER THAN 50 H	106	53
	KML12EP02 KML E MOTOR REWINDS GREATER 50	45	23
	KML12EP03 KML E PUMP REPLACEMENT DR 50 H	260	130
	KML12EP04 KML E LIGHTING PANEL REPLACEME	55	27
	KML12EP05 KML E POWER CABLE REPLACEMENT	51	26
	KML12EP06 KML E VALVE REPLACEMENT 6 IN G	226	113
	KML12EP07 KML E CIRCUIT BREAKER REPLACEM	10	5

Mitchell Plant Estimated 2012 Capital Expense			
Actuals through August and 2012 Control Budget amounts for Sept-December			
Included in Asset Transfer Analysis 12-31-13 NBV Forecast			
Dollars in Thousands			
Mitchell Unit Number	Project	2012 Total - 100% of Mitchell	2012 Total - 50% of Mitchell
	KML12EP11 ML E CONTAINMENTS	2	1
	KML12EP26 KML E WORLD CLASS CHEMISTRY	85	42
	KML12EP55 KML E HVAC REPLACE	8	4
	KML12EP56 KML MISC ELECTRICAL PROCESS IT	60	30
	KML12EP57 ML SULFURIC TANK REPLACE	5	2
	KML12MP01 KML MH COAL CHUTE REPLACEMENT	28	14
	KML12MP02 KML MH CONVEYOR BELT REPLACEME	172	86
	KML12MP03 ML MH RIVER CELL LIGHTING	28	14
	KML12MP04 ML MH LIMESTONE STAMBLER	91	46
	KML12MP05 KML MH GEARBOX REPLACEMENT	14	7
	KML12NP01 KML NP PLANT LABOR FOR CAPITAL	254	127
	KML12NP05 KML PURCHASE CSP	56	28
	KML12NP06 KML PURCHASE TOOLS	16	8
	KML12NP09 KML SAFETY RELATED PURCHASES	11	6
	KML12SP02 ML0 S PULVERIZER REBUILD CAP	373	186
	KML12SP03 ML0 S PULVERIZER REBUILD CAPIT	372	186
	KML12SP06 ML0 S PRECIPITATOR LINE GATE V	5	2
	KMLFALFCI ML New Landfill	2,009	1,005
	KMLFALFHR ML New Landfill Haul Road	6,745	3,372
	ML0SC8001 ML0-S-AUX BOILER REPLACEMENT	13,629	6,815
	ML0VP1201 ML NON OUTAGE PPB FGD	170	85
	ML11VPN01 ML NON OUTAGE PPB FGD	4	2
	ML11VPN02 ML0 V BALL MILL REBUILD	(5)	(3)
	ML12VPN02 ML0 V BALL MILL REBUILD	157	79
	MLMPHSTCI ML HS TUNNEL CI	18	9
	MLPNRXDEP ML NRX Asset Hub Deployment	196	98
	WSN103015 ML0-Conners Run Expansion	1,251	626
Mitchell Plant Unit 0 Total		55,329	27,664

Mitchell Plant Estimated 2012 Capital Expense Actuals through August and 2012 Control Budget amounts for Sept-December Included in Asset Transfer Analysis 12-31-13 NBV Forecast *Dollars in Thousands*			
Mitchell Unit Number	Project	2012 Total - 100% of Mitchell	2012 Total - 50% of Mitchell
Mitchell Plant Unit 2	000020315 ML U2 Ash WWT System	572	286
	ARCFLA181 Arc Flash Protection Swi OPCo	13	7
	FHNERC181 FHG NERC PPB OPCO	2	1
	GWSCB Cap Blkt - Prod Plant Blnkt	230	115
	KML11EP02 KML E MOTOR REWINDS GREATER 50	0	0
	KML11EP09 KML E AIR COMPRESSOR RPL	26	13
	KML11EP10 ELECTRICAL #3	(5)	(2)
	KML11EP14 KML E MISC ELECTRICAL PROCESS	(1)	(1)
	KML11EP51 ML2 PRECIPITATOR LIGHTING	1	0
	KML11EP53 ML2 STAND BY LIGHTING TRANSFOR	8	4
	KML11SP05 ML2 #21 PULVERIZER REBUILD	3	2
	KML11SP07 SP #1	0	0
	KML12EC01 ML PURCHASE BFP	175	87
	KML12EP01 KML E MOTORS GREATER THAN 50 H	9	5
	KML12EP03 KML E PUMP REPLACEMENT DR 50 H	32	16
	KML12EP04 KML E LIGHTING PANEL REPLACEME	0	0
	KML12EP06 KML E VALVE REPLACEMENT 6 IN G	64	32
	KML12EP26 KML E WORLD CLASS CHEMISTRY	17	8
	KML12EP55 KML E HVAC REPLACE	1	1
	KML12EP56 KML MISC ELECTRICAL PROCESS IT	17	9
	KML12SP08 KML S INSTRUMENTATION RPL	10	5
	KML12SP10 ML S AIR HEATER SEALS	49	24
	MLOPMCEMS ML PM CEMS NSR EMISSIONS	70	35
	ML0VP1201 ML NON OUTAGE PPB FGD	22	11
	ML213EP50 ML2 E TURBINE EBOP MOTOR	3	2
	ML2E12C05 MLU2 LPA & LPB TURB INSPECT	3,029	1,514
	ML2EP1201 ML2 E DOG BONE EJ REPLACEMENT	149	75
	ML2EP1205 ML2 E EHC PP RPL	294	147
	ML2EP1206 ML2 E CONTROLS RECORDERS GAUGE	58	29
	ML2EP1210 ML2 E CABLE VAULT FIRE SYSTEM	112	56
	ML2EP1213 ML2 E INLET SCREENS	2	1
	ML2EP1214 ML2 E MONITORING SYSTEM	451	225
	ML2EP1215 ML2 E WESTRONIC SMARTMUX RPL	76	38
	ML2EP1216 ML2 E CLEAN UP SYSTEM RESIN RP	7	3
	ML2EP1217 ML2 TRANSFORMER BUSHINGS	13	7
	ML2EP1220 ML2 E CONTROL AIR DRYER REPLAC	108	54
	ML2MP1201 ML2 MH VAC PIPING CH INSTALL	95	47
	ML2SC1501 ML2 S AIR HEATER BASKET REPLAC	1,649	824
	ML2SP1202 ML2 S CLINKER GRINDER RPL	58	29
	ML2VC1101 ML2 FGD ABSORBER COATING	2,092	1,046
	ML2VC1201 ML2 Replace 1st Catalyst Layer	1,106	553
	ML2VC1401 ML2 V CATALYST REPLACEMENT 1 L	249	125
	ML2VP1302 ML2 V INSTALL AR PP DISCHARGE	403	201
Mitchell Plant Unit 2 Total		11,268	5,634
Grand Total 2012		71,593	35,797

2013 Mitchell Plant Capital Forecast			
Included in Asset Transfer Analysis 12-31-13 NBV Forecast			
Dollars in Thousands			
		100% of Mitchell	50% of Mitchell
Mitchell Unit Number	Project		
Mitchell Plant Unit 0	000019836 ML U1&2 Dry Fly Ash Conversion	54,798	27,399
	KML13EP01 KML E MOTORS GREATER THAN 50 H	183	91
	KML13EP02 KML E MOTOR REWINDS GREATER 50	137	68
	KML13EP03 KML E PUMP REPLACEMENT	296	148
	KML13EP04 KML E LIGHTING PANEL REPLACEME	45	22
	KML13EP05 KML E POWER CABLE REPLACEMENT	55	27
	KML13EP06 KML E VALVE REPLACEMENT 6 IN G	171	86
	KML13EP07 KML E CIRCUIT BREAKER REPLACEM	27	14
	KML13EP11 ML E CONTAINMENTS	34	17
	KML13EP55 KML E HVAC REPLACE	46	23
	KML13MP01 KML MH COAL CHUTE REPLACEMENT	114	57
	KML13MP02 KML MH CONVEYOR BELT REPLACE	171	86
	KML13NP01 KML NP PLANT LABOR FOR CAPITAL	406	203
	KML13SP02 ML0 S PULVERIZER REBILD CAP	369	185
	KML13SP03 ML0 S PULVERIZER REBUILD CAP	374	187
	KML13SP06 ML0 PRECIPITATOR LINE GATE V	14	7
	KMLFALFCI KML New Landfill	21,989	10,995
	KMLFALFHR ML New Landfill Haul Road	10,568	5,284
	ML0SC8001 ML0-S-AUX BOILER REPLACEMENT	283	142
	ML0VP1301 CAP BLKT-PROD PLANT BLNKT	274	137
	ML13VPN02 ML0 V BALL MILL REBUILD	266	133
	WSN103015 ML0-Conners Run Expansion	1,105	553
Mitchell Plant Unit 1	000020312 ML U1 Ash WWT System	1,529	764
	000021257 ML U1 ESP Upgrades	4,527	2,264
	KML13SP01 ML S PULVERIZER GEARBOX	224	112
	ML1E13C05 ML1 LP TURBINE INSPECTION	668	334
	ML1E13P01 ML1 E BFPT COUPLING RPL	145	73
	ML1E13P02 ML1 E CONTROLS AND RECORDERS	68	34
	ML1E13P05 ML1 E BFPT INSPECTION	310	155
	ML1E13P10 ML1 E CABLE VAULT FIRE SYSTEM	96	48
	ML1E13P50 ML1 E EBOP MOTOR STARTER	74	37
	ML1EP1316 ML1 E MONITORING SYSTEM	416	208
	ML1EP1320 ML1 E CONTROL AIR DRYER REPLAC	102	51
	ML1EP1326 ML1 VALVE REPLACEMENT	55	27
	ML1MP1301 ML1 MH VAC PIPING CH	(0)	(0)
	ML1S13P02 ML1 S BOILER EJ RPL	134	67
	ML1SC1301 ML1 S AIR HEATER BASKET REPLAC	5,313	2,657
	ML1SP1301 ML1 S PRECIPITATOR EJ REPLACEM	194	97
	ML1SP1320 ML1 PENTHOUSE SEAL AIR VENT	329	165
	ML1SP1330 ML1 S CLINKER GRINDER HOPPER	0	0
	ML1VC1305 ML1 ID FANS	225	113
	ML1VC1401 ML1 V CATALYST REPLACEMENT 1 L	1,483	741
	ML1VP1303 ML1 V FGD CAPITAL PROJECTS	0	0
	ML2EP1320 ML2 E ELECTRICAL	0	0
	MLU113CO1 ML1 E BFPT INSPECTION	(0)	(0)
Mitchell Plant Unit 2	000020315 ML U2 Ash WWT System	1,529	764
	ML2E13P50 ML2 E EBOP MOTOR STARTER	74	37
	ML2EP1315 ML2 E WESTRONIC SMARTMUX RPL	52	26

Mitchell Unit Number	Project			
	ML2SP1301	ML2 S PRECIPITATOR EJ	199	100
	ML2SP1320	ML2 S PENTHOUSE SEAL AIR VENT	344	172
	ML2VC1205	ML2 ID FANS	231	116
	ML2VC1401	ML2 V CATALYST REPLACEMENT 1 L	1,527	764
	ML2VP1301	ML2 FGD CAPITAL OUTAGE PROJECT	158	79
	ML2VP1302	ML2 V INSTALL AR PP DISCHARGE	516	258
Total			112,246	56,123

Kentucky Power Company

REQUEST

Refer to paragraph 12 of the Application where it states, "[T]he Mitchell generating station consists of two base load coal-fired electric generating units with a total average annual capacity rating of 1,560 MW. Unit 1 of the Mitchell generating station has an average annual capacity rating of 770 MW; Unit 2 has an average annual capacity rating of 790 MW." Also, refer to Exhibit 3, page 2, of the Application where it states, "WHEREAS, Appalachian and KPCo 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")." Reconcile the difference between the capacity rating for the two Mitchell units mentioned in paragraph 12 of the Application (i.e., 770 MW for unit 1 and 790 MW for unit 2) and Exhibit 3, page 2 (i.e., 800 MW for each unit).

RESPONSE

The Mitchell generating units each have a nominal rating of 800 MW. This is a common reference to units of this boiler series and/or design. The 770 MW and 790 MW ratings are the average annual output of these specific units based on weather-normalized testing data from the units and are utilized for reporting needs to the PJM regional transmission organization and the Reliability First Corporation NERC region. The variation in the ratings from nominal arises primarily due to the auxiliary load of environmental control equipment (e.g., flue gas desulfurization or "scrubbers").

WITNESS: Jeffery D LaFleur

Kentucky Power Company

REQUEST

Refer to paragraph 19 of the Application where it states, "[F]ollowing termination of the Pool Agreement, the Company will be required to have sufficient generation to meet its load and reserve obligation." Provide separately by year, from 2014 to 2024, Kentucky Power's estimated generation, estimated load obligation, and estimated reserve obligation.

RESPONSE

Please refer to Exhibit SCW-1 (page 8 of 15) of the direct testimony of Company witness Weaver, specifically, "Section G. SUMMARY: KPCo's current and potential PJM capacity positions". This discussion describes the derivation of KPCo's PJM load/reserve obligation for the years in question from two perspectives. The first perspective offers a "going in" KPCo capacity position in which the Big Sandy 1 and 2 units are both retired, but not yet replaced (as summarized on Table 1-3 [page 9 of 15] of Exhibit SCW-1). The second perspective offers a "final" KPCo capacity position in which the recommended Mitchell Asset Transfer as well as an assumed 250 MW market purchase are reflected which would allow the Company to achieve these PJM obligations going-forward in lieu of those Big Sandy units (as summarized on Table 1-4 [page 10 of 15] of Exhibit SCW-1).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to paragraph 21 of the Application where it states, "[T]he Transfer and Assumption Transaction is intended to permit the Company to meet its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements." Explain whether the Transfer and Assumption Transaction is the least-cost and most cost-effective means for Kentucky Power to comply with existing and anticipated environmental requirements.

RESPONSE

The (Mitchell) Transfer and Assumption Transaction is the least-cost and most cost-effective means for Kentucky Power to comply with known and emerging environmental requirements.

Please refer to Company witness Weaver's direct testimony Section V. "Planning Process and Impending Environmental Requirements" (pages 8-15) along with Section VII "Evaluation of Modeling Results" (pages 28-40) --including Exhibit SCW-5-- for both a description and summary of the evaluation.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to paragraph 27 of the Application, pages 11-12, and Exhibit 3, the Mitchell Plant Operating Agreement.

a. Provide Kentucky Power's definition of "good utility practice." Explain whether there are internal or external reviews or audits to assess this.

b. State whether there are written procedures used by Appalachian Power as identified in Section 1.1 of Exhibit 3.

c. State whether this type of agreement is in use elsewhere.

RESPONSE

a. Kentucky Power's definition of "good utility practice" is based upon the Federal Energy Regulatory Commission's (FERC) definition of such in section 1 of FERC's Standard Large Generator Interconnection Procedures ("LGIP"). Section 1 of the Standard LGIP defines "Good Utility Practice" to mean:

 "Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region." [i]

 The Company relies on audits, formal and informal, to meet the objective of good utility practice. The Company engages in good utility practices, procedures, and inspections (both written and unwritten) that continually change due to the conditions and the experiences of the Company and other various utilities.

b. Yes, there are both written and unwritten procedures.

c. There are similar operating agreements in place throughout the AEP system.

WITNESS: Jeffery D LaFleur

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[i] See Standardization of Generator Interconnection Agreement and Procedures, Order No. 2003, 68 Fed. Reg. 49,845, Appendix C at 4 (August 19, 2003), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶31,146 (2003), order on reh 'g, Order No. 2003-A, 69 Fed. Reg. 15,932 (March 26, 2004), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶31,160 (2004), order on reh'g, Order No. 2003-B, 70 Fed. Reg. 265 (January 4, 2005), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶31,171 (2004), order on reh'g, Order No. 2003-C, 70 Fed. Reg. 37,661 (June 30, 2005), FERC Stats. and Regs., Regulations Preambles 2001-2005 ¶31,190 (2005); see also Notice Clarifying Compliance Procedures, 106 FERC ¶61,009 (2004).

Kentucky Power Company

REQUEST

Refer to paragraph 30 of the Application which states, ". . . there are no capacity equalization payments required under the Power Coordination Agreement."

a. Provide Kentucky Power's actual capacity equalization payments, by month, from 2008 to 2012.

b. If Kentucky Power were to purchase energy from either Appalachian Power Company or Indiana Michigan Power Company under the Power Coordination Agreement, explain how the energy would be priced and state whether there would be any associated transmission charge.

RESPONSE

a. Please see KPSC 1-7 Attachment 1 for Kentucky Power's actual capacity equalization payments, by month, from 2008 to 2012.

b. The Power Coordination Agreement does not provide for energy transactions between Kentucky Power and its affiliated operating companies.

WITNESS: Ranie K Wohnhas

Kentucky Power - Capacity Equalization Payments

Jan08	($3,714,122)		Jan11	($4,785,665)
Feb08	($3,827,012)		Feb11	($4,716,261)
Mar08	($3,915,346)		Mar11	($4,886,856)
Apr08	($4,138,446)		Apr11	($4,914,969)
May08	($4,194,177)		May11	($4,844,515)
Jun08	($3,959,874)		Jun11	($4,786,681)
Jul08	($4,157,357)		Jul11	($4,810,752)
Aug08	($4,075,591)		Aug11	($3,861,944)
Sep08	($4,865,078)		Sep11	($6,196,900)
Oct08	($4,793,805)		Oct11	($3,574,142)
Nov08	($4,751,761)		Nov11	($3,679,275)
Dec08	($5,276,715)		Dec11	($3,464,791)
Jan09	($4,678,080)		Jan12	($2,633,449)
Feb09	($4,265,617)		Feb12	($3,061,188)
Mar09	($4,476,614)		Mar12	($1,462,620)
Apr09	($4,478,997)		Apr12	($1,454,640)
May09	($4,702,227)		May12	($1,463,760)
Jun09	($4,480,173)		Jun12	($1,418,160)
Jul09	($4,740,041)		Jul12	($1,467,180)
Aug09	($4,917,888)		Aug12	($1,878,148)
Sep09	($4,798,246)		Sep12	($1,840,098)
Oct09	($5,010,477)		Oct12	($1,854,699)
Nov09	($4,925,341)		Nov12	($1,888,117)
Dec09	($5,787,837)		Dec12	($1,895,396)
Jan10	($5,970,139)			
Feb10	($4,896,445)			
Mar10	($5,173,477)			
Apr10	($4,883,278)			
May10	($4,942,396)			
Jun10	($5,909,940)			
Jul10	($5,344,809)			
Aug10	($4,199,672)			
Sep10	($4,216,537)			
Oct10	($4,167,274)			
Nov10	($4,202,670)			
Dec10	($4,507,572)			

Kentucky Power Company

REQUEST

Refer to paragraph 36, pages 15-16, of the Application, which states, "Kentucky Power performed a thorough review of reasonable alternatives to meet its capacity and energy requirements, including energy efficiency resources, and determined the Transferred Assets are the least cost, reasonable alternative for meeting the Company's capacity and energy requirements."

a. Provide a list of the energy efficiency programs reflected in the aforementioned review, along with each program's associated energy savings and the cost to implement the energy savings program.

b. State whether any cost benefit analysis was performed on these energy efficiency programs. If yes, provide the cost benefit analysis. If no, explain why.

c. State whether any costs associated with the energy efficiency programs are reflected in Kentucky Power's review.

d. State whether Kentucky Power's review of reasonable alternatives to meet its capacity and energy requirements included an analysis in which it would receive more than the planned 50 percent undivided ownership in the Mitchell Plant. If yes, provide the analysis. If no, explain why such an analysis was not performed.

Kentucky Power Company

RESPONSE

a. Implicit in the Company's load peak demand forecast are the energy efficiency resources detailed in Table 1-2 of Company witness Weaver's Exhibit SWC-1. A brief description of each energy efficiency program is provided as follows:

<u>Targeted Energy Efficiency Program</u>

This program will supplement the resources of not-for-profit agencies that provide weatherization services to low-income households. Energy audits, consultation, and extensive weatherization and energy conservation measures will be provided to eligible low-income customers. Low-income customers who use on the average of 700 kWh per month are eligible for the program.

<u>High Efficiency Heat Pump – Mobile Home Program</u>

Kentucky Power Company will provide a $400 incentive to mobile home customers who replace their resistant heat system with a high-efficiency heat pump. Eligible customers must live in a mobile home, have resistant heat, have service with KPCo for at least 12 months. For promoting the program, participating HVAC dealers will receive a $50 incentive for each high efficiency heat pump installed.

<u>Mobile Home New Construction Program</u>

Kentucky Power Company will provide a $500 incentive to mobile home buyers who purchase a new home with zone 3 insulation levels and a high efficiency heat pump. Participating manufactured housing dealers will also receive a $50 incentive for promoting the program.

<u>Modified Energy Fitness Program</u>

The Modified Energy Fitness Program provides Kentucky Power Company residential customers an energy audit and, where applicable, installation of energy saving measures. The audit and consultation will also identify energy conservation measures that can be implemented by the customer including education on the benefits of energy efficiency.

The primary target market will be site built and manufactured homes utilizing electric space heating and electric water heating and use a minimum average of 1,000 kWh of electricity per month.

Kentucky Power Company

High Efficiency Heat Pump Program

Kentucky Power Company will provide an incentive to residential customers living in site-built homes who purchase a new high-efficiency heat pump for upgrades of less efficient heating and cooling systems. For upgrades of an electric resistance heating system with a high efficiency heat pump (SEER greater than or equal to 13.0 SEER and 7.7 HSPF), the customer will receive an incentive of $400. For upgrades of an electric heat pump unit with a ultra high efficiency heat pump (SEER greater than or equal to 14.0 SEER and 8.2 HSPF), the customer will receive an incentive of $400. Participating HVAC dealers will also receive a $50 incentive for promoting the program.

Community Outreach Compact Fluorescent Lighting Program

This program is designed to educate and encourage Kentucky Power Company residential customers to purchase and use compact fluorescent lighting (CFLs) in their homes. A package of four energy efficient CFLs will be distributed to customers attending community outreach activities sponsored by Kentucky Power.

Energy Education for Students Program

Kentucky Power will partner with the National Energy Educational Development Project (NEED) to implement an energy education program at participating middle schools throughout the Kentucky Power service territory.

NEED staff will conduct workshops on a scheduled basis to ensure participating schools are reached during the calendar year. Educational materials on energy, electricity, environment and economics will be provided. The program will also provide a package of four energy efficient compact fluorescent lamps (CFLs) that will allow students to install the CFLs in their homes as part of the curriculum. This allows learning and direct savings from the program. All 7th grade students at participating schools will be eligible for the program.

Residential & Commercial HVAC Diagnostic and Tune-up Program

Available to Kentucky Power residential customers and small commercial customers using less than 100 kW peak demand whose primary heat source is electricity. The Kentucky Power Small Commercial HVAC Program encourages small commercial customers to keep their heating and ventilation (HVAC)

Kentucky Power Company

equipment operating at peak efficiency, either by way of a simple tune-up or an equipment upgrade.

The residential and commercial customer will receive a $30 incentive when receiving this Diagnostic and Tune-up service from a participating, state licensed contractor. The HVAC contractor receives a $25 incentive for participating and promoting the program. The diagnostic and tune-up service includes testing for inefficiencies in heat pump systems due to air-restricted indoor or outdoor coils and over or under refrigerant charge.

Small Commercial AC HP Program

Available to Kentucky Power commercial customers using less than 100 kW peak demand whose primary heat source is electricity. The Kentucky Power Small Commercial HVAC Program encourages small commercial customers to keep their heating, ventilation and air conditioning (HVAC) equipment operating at peak efficiency by an equipment upgrade.

The commercial customer will receive financial incentives ranging from $250 to $450 for upgrading to a new qualifying central air conditioning or heat pump system (up to a five-ton unit with a Consortium for Energy Efficiency (CEE) Tier 1 rating).

Residential Efficient Products

The Kentucky Power Residential Efficient Products Program (REP) offers residential customers instant rebates on ENERGY STAR lighting products at participating retail stores across our service territory. The program targets the purchase of lighting products through in-store promotion as well as special sales events. All Kentucky Power residential customers are eligible to participate.

Commercial Incentive Program

The Kentucky Power Commercial Incentive Program (CIP) offers a convenient way to receive funding for common energy efficiency projects. The Commercial Inventive Program provides financial incentives to business customers who implement qualified energy-efficient improvements and technologies.

Incentives are available for a variety of energy-saving technologies in existing buildings and new construction projects. All commercial (non-industrial) customers in Kentucky Power's service territory are eligible to participate.

Kentucky Power Company

Pilot Residential and Small Commercial Load Management

This pilot program ended 12/31/2012 and was designed to reduce peak demand through certain load management measures to assist in lowering costs and delaying future generating requirements. To participate, customers must allow the Company, or its authorized agents, to install load control equipment and, if necessary, auxiliary communicating devices to control the customer's central air conditioning, heat pumps, and/or electric water heating equipment. The program was available on a voluntary basis to individual residential customers and small commercial customers receiving retail electric service from the Company.

Interruptible Load

The Company uses Tariff C.S.-I.R.P. (Contract Service - Interruptible Power) to develop special contracts with customers whom choose to make load available for interruption. These special contract are submitted for approval to the Kentucky Public Service Commission prior to implementation.

Please see KPSC 1-8 Attachment 1 for the energy savings and costs for each program.

b. There was no additional cost benefit analysis performed by Resource Planning on KPCo programs, current or prospective. Energy and demand reductions associated with a continuation of current programs is incorporated in the load forecast and those programs are further assumed to be cost effective prospectively.

c. Costs associated with energy efficiency programs are an integral part of the cost benefit analysis. However, just as is the case with current or committed supply assets, revenue requirements associated with these "sunk" costs are not included in Strategist analyses.

d. No, an analysis in which Kentucky Power would receive more than the planned 50 percent undivided ownership in the Mitchell Plant was not performed; the only ownership options that were made available to Kentucky Power are outlined in the testimony of Company witness Weaver.

WITNESS: Scott C Weaver

Program	Evaluation Date	Measure Description	Annual Estimated Cost per 3 yr. extension	MW per year (net)	MWH per year (net)	Life Expectancy of individual program measures	TRC Retrospective	TRC Prospective	Total Benefits (Retrospective)	Total Benefits (Prospective)
Community Outreach CFL (COCFL)	2011		$65,588	0.255	1,293.0	6	4.17	3.91	$357,722	$505,480
Energy Education For Students (EEFS)	2011		$29,832	0.059	488.4	6	2.04	1.65	$110,659	$174,606
High Efficiency Heat Pump (HEHP) *	2011	Resistance Heat	$84,988	0.092	238.0	15	1.74	2.03	$1,216,032	$2,984,494
		Heat Pump Replacement	$230,931	0.283	815.0	15				
Modified Energy Fitness (MEF)	2011		$430,465	0.269	729.1	7	1.15	1.37	$649,377	$1,319,448
Mobile Home Heat Pump (MHHP)	2011		$106,539	0.167	569.1	15	5.23	6.41	$766,986	$1,601,079
Mobile Home New Construction (MHNC)	2011		$112,883	0.047	322.8	15	2.25	2.64	$410,323	$620,754
Targeted Energy Efficiency (TEE)*	2011	All-Electric	$302,432	0.124	475.5	10	1.59	1.95	$1,006,092	$2,039,229
		Non-All-Electric	$2,743	0.004	23.0	10				
Commercial Incentive	2012		$1,111,106	1.049	3,415.6	10	0.63	1.32	$147,433	$778,690
Residential Efficient Products	2012		$604,270	1.027	9,656.5	5	2.39	2.39	$1,341,838	$1,341,838
Small Commercial HP/AC *	2012	HP	$23,730	0.022	47.8	15	0.76	1.18	$18,032	$45,343
		AC	$11,235	0.000	5.1	15				
HVAC DIAGNOSTIC	2012	Res HP	$37,397	0.109	251.9	5	0.88	1.03	$90,844	$85,062
		Comm HP	$8,017	0.027	79.3	5	0.96	1.1	$20,645	$18,528

* TRC benefits represent Program level versus measure specific.

Kentucky Power Company

REQUEST

Refer to paragraph 37 of the Application, which states, "Kentucky Power will submit requests to modify existing Title V permits, and other permits and licenses to reflect its transfer of an undivided fifty percent interest in the Transferred Assets."

a. Provide the amount of air emission fees paid to the State of West Virginia for the Mitchell Plant from 2008 to 2012.

b. Provide the amount of air emission fees paid to the Commonwealth of Kentucky for the Big Sandy Plant from 2008 to 2012.

c. Provide any other environmentally related fees paid by the Mitchell Plant from 2008 to 2012.

d. Provide any other environmentally related fees paid by the Big Sandy Plant from 2008 to 2012.

RESPONSE

a. The amount of air emission fees paid to the State of West Virginia for the Mitchell Plant from 2008 to 2012 is below:

2008: $197,096.63
2009: $186,028.07
2010: $145,540.41
2011: $222,712.78
2012: $233,911.74

b. The amount of air emission fees paid to the Commonwealth of Kentucky for the Big Sandy Plant from 2008 to 2012 is below:

2008: $378,457.00
2009: $366,611.00
2010: $380,382.00
2011: $506,715.00
2012: $471,193.00

c. Other environmental fees to regulatory agencies are typically minor compared to the annual air emission fees. The scope of other environmental fees can include annual fees associated with permitting and regulatory programs, as well as fees to submit applications for new, modified, or renewed permits. These fees are not separately tracked; however, an estimate of those fees follows:

2008: < $10,000
2009: < $15,000
2010: < $10,000
2011: < $15,000
2012: < $65,000

d. Other environmental fees to regulatory agencies are typically minor compared to the annual air emission fees. The scope of other environmental fees can include annual fees associated with other permitting and regulatory programs, as well as any fee to submit applications for new, modified, or renewed permits. These fees are not separately tracked; however, an estimate of those fees follows:

2008: < $5,000
2009: < $5,000
2010: < $5,000
2011: < $5,000
2012: < $5,000

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to paragraph 39 of the Application where it states, "[U]sing the actual 2011 cost incurred as an estimate of Kentucky Power's annual operation and maintenance cost of the Transferred Assets, these costs were $134.9 million for operations and $15.5 million for maintenance in 2011."

a. Provide the total operation and maintenance cost for the Mitchell Plant, broken down by Unit for 2010, 2011, and 2012 and projected for 2013, 2014, and 2015.

b. Provide the fuel cost on a per kWh basis for the Mitchell Plant, broken down by Unit for 2010, 2011, and 2012 and projected for 2013, 2014, and 2015.

c. State whether any incremental transmission facilities are required to be installed as a result of Kentucky Power's fifty percent ownership in the Mitchell Plant. If so, provide the estimated associated investment in and/or cost of these facilities.

d. State whether Kentucky Power will incur any incremental transmission cost as a result of its fifty percent ownership in the Mitchell Plant. If so, identify the types of cost and provide the estimated annual amount.

RESPONSE

a. The Mitchell Plant total O&M costs for 2010-2012 are shown below. Mitchell Unit 0 costs represent plant equipment and systems shared by both Units 1 and 2 that are not specifically assigned by unit.

Kentucky Power Company

Mitchell Plant Total O&M - Post-Allocated Actuals				
		Years		
Unit	**Type**	**2010**	**2011**	**2012**
Mitchell 0	A&G	$444,543	$408,470	$678,476
	Consumables	$6,793,105	$6,912,101	$7,113,535
	Environmental	($102)	$200	$188
	Fuel	$370,421	$725,706	$1,123,823
	Maintenance	$11,740,006	$11,659,061	$13,455,018
	Operations	$5,681,263	$6,566,792	$8,459,520
	Other O&M	($4,665)	($7,684)	$23,283
	Removal Exp	$96,138	$215,108	$1,193,956
Mitchell 0 Total		**$25,120,709**	**$26,479,755**	**$32,047,798**
Mitchell 1	Consumables	$3,327,313	$3,020,178	$3,568,237
	Fuel	$123,285,960	$103,840,184	$118,541,347
	Maintenance	$5,998,798	$11,973,069	$7,022,178
	Operations	$887,400	$743,695	$640,004
	Other O&M	$13,446	$17,539	$2
	Removal Exp	$624,462	$1,105,356	$864,627
Mitchell 1 Total		**$134,137,379**	**$120,700,021**	**$130,636,394**
Mitchell 2	Consumables	$3,389,472	$3,916,801	$2,577,309
	Fuel	$125,455,921	$131,261,801	$97,445,341
	Maintenance	$5,404,070	$5,816,013	$11,689,271
	Operations	$323,779	$129,567	$174,496
	Other O&M	$11,660	$10,616	$2
	Removal Exp	$727,085	$673,340	$2,543,714
Mitchell 2 Total		**$135,311,988**	**$141,808,138**	**$114,430,134**

The 2013-2015 projected O&M costs are based on budget estimates and are shown in the table below. The 2014-2015 projections are used in the economic analysis supporting the proposed asset transfer.

O&M Used In the Company's Economic Analysis (Excluding Fuels and Consumables)				
		$000		$000
		OM		OM
		Mitchell 1		Mitchell 2
2013		15,319		11,929
2014		12,296		12,199
2015		12,321		15,661

Kentucky Power Company

b. The table below shows the $/kWh fuel costs for Mitchell units 1 and 2. Please note that consumed fuel cost is not available on a unit basis. The total plant fuel cost was allocated to each unit based on that unit's generation (MWh) and heat rate (BTU/kWh).

	Annual Fuel Cost ($/kWh)	
Year	Mitchell Unit 1	Mitchell Unit 2
2010	$0.02420	$0.02270
2011	$0.02547	$0.02414
2012	$0.02808	$0.02602

Refer to KPSC 1-10 Attachment 1 for the forecasted base commodity pricing for delivered cost of fuel ($/KWh) for the Mitchell units for 2013-2015 based on commodity price forecasts. Confidential treatment is being sought for portions of Attachment 1. The 2014-2015 projections are used in the economic analysis supporting the proposed asset transfer. The 2013 projects are not included in the economic analysis.

c. No incremental transmission facilities are expected to be required.

d. KPCo's fifty percent ownership in the Mitchell Plant is not expected to result in any incremental transmission costs to KPCo.

WITNESS: Jeffery D LaFleur

Annual Forecasted ($/kWh)

Year	Mitchell 1	Mitchell 2
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

Kentucky Power Company

REQUEST

Provide, by unit, Big Sandy Plant's fuel cost on a per kWh basis for calendar years 2010, 2011, and 2012 actual and 2013, 2014, and 2015 estimated.

RESPONSE

The following table show the historic fuel cost, in \$/kWh, for the Big Sandy Plant. Please note that consumed fuel cost is not available on a unit basis. The total plant fuel cost was allocated to each unit based on that unit's annual generation (MWh) and heat rate (BTU/kWh).

	Annual Fuel Cost (\$/kWh)	
Year	Big Sandy Unit 1	Big Sandy Unit 2
2010	\$0.02509	\$0.02596
2011	\$0.02894	\$0.02893
2012	\$0.03258	\$0.03159

KPSC 1-11 Attachment 1 provides the forecasted values as requested. Confidential treatment is being sought for portions of Attachment 1.

WITNESS: Ranie K Wohnhas

Big Sandy Fuel Cost ($/kWh)
2013-2015

	Annual Fuel Cost ($/kWh)	
Year	Big Sandy Unit 1	Big Sandy Unit 2
2013	[redacted]	[redacted]
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]

Kentucky Power Company

REQUEST

Refer to paragraph 39 of the Application, which states, "[I]n addition, using these and other 2011 values to reflect the effects of the Mitchell transfer and the termination of the current Pool Agreement on KPCo, the Company's cost of service would have increased approximately eight percent". Provide in electronic format, with formulas intact and unprotected, the analysis supporting the approximate 8 percent increase, along with the assumption(s) used in the analysis.

RESPONSE

See KPSC Staff 1-12 Attachments 1 and 2 on the enclosed disk for the requested analysis and supporting workpapers.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to paragraph 44 of the Application where it states, "[W]ithin six months of closing of the Transfer and Assumption Transaction, Kentucky Power anticipates issuing debt in the approximate amount of $275 million." Provide the final anticipated split between debt and equity of the Transfer and Assumption Transaction.

RESPONSE

The intent of the recapitalization as a result of the Transfer and Assumption Transaction is to keep the capital structure relatively unchanged from the pre-transaction total GAAP capitalization of 54% debt and 46% equity.

WITNESS: Ranie K. Wohnhas

Kentucky Power Company

REQUEST

Refer to paragraph 44 of the Application, which states:

> In addition, the rights and liabilities associated with the West Virginia Economic Development authority ("WVEDA") Pollution Control Revenue Bond ("PCRB")[i] that partially Financed the FGD units constructed at the Mitchell Generating station will be transferred to Kentucky Power This $65 million WVEDA bond for Mitchell is currently held in Trust by Ohio Power and may be reissued by Kentucky Power.

a. State whether the $65 million WVEDA bond increased the debt associated with the Transfer and Assumption Transaction or whether the $65 million is included in the $275 million anticipated debt issuance.

b. State whether the $65 million WVEDA bond associated with the Mitchell Plant flue-gas desulfurization ("FGD") will be held in trust by Kentucky Power.

c. Explain why the $65 million WVEDA bonds associated with the Mitchell Plant FGD should be held in trust, including any benefits to Kentucky Power and its ratepayers of doing so.

RESPONSE

a. It is not the Company's intention to increase the targeted $275 million anticipated debt issuance by the amount of the $65 million WVEDA bond.

b/c. Initially the $65 million WVEDA bond would be held in trust. The trust concept means that Kentucky Power is both the bond holder and the issuer until the bonds are reissued to the public and the proceeds are received. Kentucky Power will be able to issue the $65 million bond out of the trust at any time. By having the option to issue tax-exempt debt Kentucky Power and their rate payers will benefit by having the ability to diversify their debt portfolio and reduce their embedded cost of long-term debt because tax-exempt bonds traditionally have cost less than taxable bonds.

WITNESS: Ranie K Wohnhas

[i] West Virginia Economic Development Authority $65,000,000 series 2008A Mitchell PCRB.

Kentucky Power Company

REQUEST

Refer to paragraph 70 of the Application, pages 24-25, which states:

Based upon the Company's re-evaluation, Kentucky Power concluded that the transfer of a fifty percent undivided interest in the Mitchell generating station and the retirement of Big Sandy Unit 2 by June 2015 is the least cost alternative for meeting its long-term capacity obligations and to provide base load generation to meet its customers' energy requirements.

a. Provide, by unit, the generating capacity that will be available to Kentucky Power from January 2014 to May 2015, the projected load for this time period, and state whether Kentucky Power will have surplus generating capacity.

b. If Kentucky Power will have surplus generating capacity from January 2014 to May 2015, provide the Company's plans for its surplus generating capacity.

c. If Kentucky Power will have surplus energy from January 2014 to May 2015, provide the company's plans for the surplus energy.

RESPONSE

a. See KPSC Staff 1-15 Attachment 1 for the generating capacity that will be available to Kentucky Power from January 2014 to May 2015. Kentucky Power will have surplus generating capacity for this time period. See KPSC Staff 1-15 Attachment 2 for the projected load.

b. During this period, Kentucky Power's capacity resources, along with those of the other AEP-East Operating Companies, have already been committed under a common PJM capacity plan. PJM capacity sales already committed during this period will be allocated among the operating companies based upon final MLR.

c. To the extent Kentucky Power has surplus energy available from its generation resources, this energy will be offered for sale, predominantly in PJM. Proceeds from these surplus energy sales will be directly assigned to Kentucky Power.

WITNESS: Scott C Weaver

	Total Unit Capacity (MW ICAP)	KPCo Allocation	KPCo Unit Capacity (MW ICAP)
Big Sandy 1	278	100%	278
Big Sandy 2	800	100%	800
Mitchell 1	770	50%	385
Mitchell 2	790	50%	395
Rockport 1	1,315	15.0%	197
Rockport 2	1,300	15.0%	195
Total	**5,253**		**2,250**

Kentucky Power Company
Internal Energy (in GWh)
Prior to EE/DR

Month-Year	Internal Energy in GWh
Jan-14	769
Feb-14	657
Mar-14	643
Apr-14	562
May-14	558
Jun-14	591
Jul-14	618
Aug-14	637
Sep-14	546
Oct-14	553
Nov-14	611
Dec-14	719
Jan-15	770
Feb-15	659
Mar-15	646
Apr-15	564
May-15	560

Kentucky Power Company

REQUEST

Refer to paragraph 71 of the Application, which references a requested deferral of $29,287,494 in incremental costs associated with the Phase I investigation of a FGD. Also, refer to Case No. 2011-00401,[i] the response to Item 18.b. of Commission Staff's First Request for Information, which provides support for $15,212,425 in costs incurred during the 2004 to 2006 time frame for preliminary analysis of a wet FGD technology.

a. Reconcile the differences in the two amounts.

b. Provide a breakdown showing, by year, the time over which the $29,287,494 cost was incurred.

RESPONSE

a. Please see KPSC 1-16 Attachment 1.

b. Please see KPSC 1-16 Attachment 2. Charges were originally recorded in FERC account 107 but transferred to FERC account 183 at various times when the project was suspended. The amounts were transferred back to FERC account 107 when the project was restarted until the latest suspension of the project which occurred in August 2012 for the FGD costs and December 2012 for the landfill. The total charges of $28,774,244 are now recorded in FERC account 183 as of December 31, 2012 as shown in KPSC 1-16 Attachment 2.

   There $28,774,244 is a reduction from the filed deferral amount of $29,287,494. An explanation and reconciliation is as follows:

   The difference between the November balances filed in December and the December 31, 2012 balances mainly relates to the estimated value of the landfill related to the FGD. In the November balance, the estimated amount of the landfill was $3,560,022 million as shown in RKW-Exhibit 5. In December, when the landfill project was suspended and reviewed to move the amounts to account 183, it was determined that the correct amount to be transferred from account 107 to account 183 was $3,053,267 million.

Kentucky Power Company

Also, an amount of $6,495 was inadvertently included in the total amount used in the filing but was not included in account 183 deferred amounts on KPCo books at both November 30, 2012 and December 31, 2012.

Reconciliation of November 30, 2012 BS2 Scrubber Costs
to December 31, 2012 Monthly Charges

		Landfill		FGD		Total
RKW-Exhibit 5	$	3,560,022	$	25,727,472	$	29,287,494
Total Charged to Acct. 107 @ 12/31/12		3,053,267		25,720,977		28,774,244
Difference	$	(506,755)	$	(6,495)	$	(513,250)

Also see KPSC 1-64 where land identified in the amount o $630,376 will be reclassified from account 183. With the adjustment of $513,250 detailed above, and the reclassification of land from 183, the company's original deferral requests changes from $29,287,494 to $28,143,868.

WITNESS: Ranie K Wohnhas

[2] Case No. 2011-00401, Application of Kentucky Power Company for Approval of Its 2011 Environmental Compliance Plan, for Approval of Its Amended Environmental Cost Recovery Surcharge Tariff, and for the Grant of a Certificate of Public Convenience and Necessity for the Construction and Acquisition of Related Facilities (Ky. PSC May 31, 2012).

	As Filed 2011-00401	As Filed 2012-00578	Change
FGD Landfill (1)	$ 1,648,741	$ 3,560,022	$ 1,911,281
WFGD (2)	$ 13,563,684	$ 13,563,577	$ (107)
DFGD (3)	$ -	$ 12,163,895	$ 12,163,895
Total	$ 15,212,425	$ 29,287,494	$ 14,075,069

(1) Additional cost as landfill would be required for both the WFGD and DFGD.
(2) Slight adjustment made in review of all WFGD costs.
(3) DFGD costs incurred.

		Account	
Component	Month	1830000	1070001
Big Sandy FGD Landfill	200404		6,027.02
	200405		15,278.36
	200406		15,376.37
	200407		24,116.99
	200408		39,488.57
	200409		37,245.23
	200410		23,294.86
	200411		15,068.55
	200412		104,249.44
	200501		51,927.73
	200502		77,864.74
	200503		31,606.44
	200504		33,970.05
	200505		26,652.69
	200506		37,191.00
	200507		79,697.78
	200508		35,988.64
	200509		46,680.06
	200510		68,429.41
	200511		115,205.82
	200512		706,768.30
	200601		47,261.88
	200602		60,414.28
	200603		68,425.52
	200604	1,648,741.38	(1,734,216.85)
	200605	47,368.77	(33,673.22)
	200606	5,668.28	(339.66)
	200607	35,449.23	(0.00)
	200608	81,374.91	(0.00)
	200609	80,677.42	(0.00)
	200610	34,052.21	0.00
	200611	583.59	(0.00)
	200612	6,945.96	-
	200701	6.39	-
	200702	26,500.71	-
	200704	358.00	-
	201007	127.26	-
	201008	(1,967,854.11)	1,970,979.64
	201009		4,189.42
	201010		11,787.93
	201011		69,173.76
	201012		121,954.03
	201101		142,031.04
	201102		(19,844.39)
	201103		38,258.75
	201104		51,435.15
	201105		20,812.01
	201106	2,416,019.51	(2,410,777.34)

		Account	
Component	Month	1830000	1070001
	201110	(139.91)	-
	201111	(2,415,879.60)	2,428,120.21
	201112		22,657.12
	201201		24,947.43
	201202		32,732.31
	201203		240,077.04
	201204		480,448.44
	201205		220,265.90
	201206		182,385.96
	201207		103,622.29
	201208		103,616.26
	201209		81,196.28
	201210		112,659.13
	201211		103,353.47
	201212	3,053,266.72	(4,136,081.84)
Big Sandy FGD Landfill Total		3,053,266.72	(0.00)
BIG SANDY U2 DFGD W/ FF	200407		13.62
	200408		11,973.55
	200409		39,656.39
	200410		109,638.87
	200411		108,179.22
	200412		123,624.80
	200501		109,199.25
	200502		168,138.44
	200503		223,900.28
	200504		317,045.56
	200505		340,591.76
	200506		476,393.81
	200507		1,547,993.86
	200508		869,465.69
	200509		1,763,496.07
	200510		338,610.32
	200511		2,742,735.75
	200512		2,104,636.24
	200601		832,347.29
	200602		1,386,440.56
	200603		1,113,192.32
	200604	13,563,683.54	(14,019,473.19)
	200605	733,301.56	(701,573.03)
	200606	22,230.25	(6,227.43)
	200607	(78,220.65)	-
	200608	(567.21)	0.00
	200609	474,023.76	0.00
	200610	(90,509.35)	-
	200806	41,739.72	-
	200807		-
	200808	445,393.10	-
	200809	25,004.71	-
	200810	575.03	-
	200811	1,139.86	-

		Account	
Component	Month	1830000	1070001
	200812	111,813.05	-
	200901		-
	200902		-
	200903	29,761.90	-
	200904	1,981.51	-
	200905		-
	200906		-
	200907		-
	200908		-
	200909		-
	200910	40,320.44	-
	200911	60,817.32	-
	200912	162,252.11	-
	201001	402,538.93	-
	201002	8,159.15	-
	201003	12,079.79	-
	201004	90,119.96	-
	201005	104,301.46	-
	201006	102,266.11	-
	201007	227,243.77	-
	201008	379,052.88	-
	201009	396,292.36	-
	201010	338,584.40	-
	201011	156,982.07	-
	201012	93,184.61	-
	201101	88,173.60	-
	201102	7,028.14	-
	201103	65,829.88	-
	201104	17,591.70	-
	201105	2,850.92	-
	201106	14,381.58	-
	201107	404.97	-
	201108	6,689.45	-
	201109	103.29	-
	201110	1,006.72	-
	201111	(18,059,606.39)	19,569,317.28
	201112		212,027.36
	201201		564,227.63
	201202		944,599.56
	201203		1,146,917.74
	201204		1,160,837.44
	201205		1,252,532.96
	201206		606,416.35
	201207		150,723.41
	201208	25,714,048.28	(25,607,599.73)
	201209	4,866.53	0.00
	201210	1,339.13	(0.00)
	201211	690.84	0.00
	201212	32.08	-
BIG SANDY U2 DFGD W/ FF Total		25,720,976.86	(0.00)

		Account	
Component	Month	1830000	1070001
Grand Total		28,774,243.58	(0.00)

Kentucky Power Company

REQUEST

Refer to Exhibit 1 of the application, Asset Contribution Agreement Between AEP Generation Resources Inc. and Newco Kentucky, Section 2.03.

a. Provide the net book value as of December 31, 2011 for each of the Assumed Liabilities listed in section 2.03 of the asset contribution agreement (i.e., Assumed Payables, Debt, Deferred Tax Liability, and Property Taxes related to the Transferred Assets).

b. Provide the net book value as of December 31, 2012 for each of the Assumed Liabilities listed in section 2.03 of the asset contribution agreement (i.e., Assumed Payables, Debt, Deferred Tax Liability, and Property Taxes related to the Transferred Assets).

c. Provide a copy of Schedule 1.02 referenced in Section 1.01 of the asset contribution agreement defining the term "Assumed Payables."

d. Provide a copy of Schedule 1.03 referenced in Section 1.01 of the asset contribution agreement defining the term "Debt."

RESPONSE

a. The actual Assumed Liabilities will not be identified until just prior to the transfer on or about December 31, 2013 as the Assumed Liabilities become known. However, for amounts as of December 31, 2011, please see Company witness Wohnhas' RKW - Exhibit 3 accounts 230, 236, 242, 282 and 283. KPCo will supplement this response when the information is known

b. The actual Assumed Liabilities will not be identified until just prior to the transfer on or about December 31, 2013 as the Assumed Liabilities become known. However, for amounts as of December 31, 2012, please see the table below including accounts 230, 236, 242, 282 and 283. KPCo will supplement this response when the information is known.

Account	Account Description	12/31/2012 Actual ($000)
230	Asset Retirement Obligations	5,140
236	Taxes Accrued	4,335
242	Miscellaneous Current and Accrued Liabilities	471
253	Other Deferred Credits	426
282	Accum. Deferred Income Taxes-Other Property	144,336
283	Accum. Deferred Income Taxes-Other	5,376
	Total	160,084

c. Schedule 1.02 Assumed Payables will not be populated until just prior to the transfer on or about December 31, 2013, as the Assumed Payables become known. KPCo will supplement this response when the information is known.

d. Schedule 1.03 Debt will not be populated until closer to the transfer on or about December 31, 2013 as the Transferor's long-term and short-term debt that will be assumed by the Transferee is identified. KPCo will supplement this response when the information is known.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to pages 4-5 of the Direct Testimony of Gregory G. Pauley ("Pauley Testimony"), which states:

It is important to recognize that although I am the President and COO of Kentucky Power, the Company is a wholly-owned subsidiary of AEP. As a result, I am responsible to AEP for the operation and performance of Kentucky Power. In fulfilling my responsibilities, I work collaboratively with AEP executive management, the management of the other AEP East operating companies, including Charles R. Patton, President and COO of Appalachian Power Company ("APCo"), (collectively "AEP Management"), and AEPSC personnel to address those matters for which I have responsibility. I regularly meet with Robert P. Powers, Executive Vice President and COO of AEP, and have access to Nicholas K. Akins, President and Chief Executive Officer of AEP, when needed. This collaboration provides Kentucky Power access to valuable resources, but, as Mr. Akins has informed the Commission, I am in charge of the Company.

Identify the person to whom Mr. Pauley reports by name and position.

RESPONSE

Mr. Pauley reports to Charles R. Patton, President and COO of Appalachian Power Company.

WITNESS: Gregory G Pauley

Kentucky Power Company

REQUEST

Refer to page 7, lines 7-14, of the Pauley Testimony, which states:

Kentucky Power is a party to an agreement dated July 6, 1951, as amended, by and between APCo, Kentucky Power, Indiana Michigan Power Company ("I&M'), and OPCo. Under the Pool Agreement, Kentucky Power and the other parties to the agreement function as an integrated system by jointly satisfying their combined needs for capacity and energy. On December 17, 2010, Kentucky Power and the then four other parties to the Pool Agreement gave notice in conformity with the three-year notice requirements of the Pool Agreement of the termination of that agreement effective January 1, 2014.

a. Provide a schedule which shows each year since Kentucky Power has been a member of the American Electric Power ("AEP") East Pool and for each year indicate whether Kentucky Power has been a deficit or surplus member.

b. For each year that Kentucky Power was a deficit company, state whether it was charged its Member Load Ratio share of the average cost of generation of the surplus members of the AEP East Pool through the capacity equalization payments, as referenced in the Application, paragraph 30.

c. If the monthly capacity equalization payments are part of Kentucky Power's base rates, state whether Kentucky Power ratepayers financially supported the generating facilities of the surplus members of the AEP East Pool during the time Kentucky Power was a deficit member.

RESPONSE

The Company has reviewed all pertinent records and responds below to the extent information is available.

a. Please see the table below for Kentucky Power's annual capacity status under the AEP East Pool Agreement.

Year	Annual Surplus (DEFICIT) CAPACITY kW
2000	(2,827,900)
2001	(3,625,600)
2002	(2,970,300)
2003	(2,403,500)
2004	(2,361,600)
2005	(4,024,700)
2006	(4,339,500)
2007	(4,355,200)
2008	(4,538,900)
2009	(4,702,100)
2010	(4,303,500)
2011	(3,790,800)
2012	(1,779,500)

b. For each month that Kentucky Power had a Member Primary Capacity Deficit it was charged the average cost of generation of the surplus members of the AEP East Pool through the capacity equalization payments.

c. Kentucky Power, when deficit, purchases capacity and associated energy services from the surplus companies, just as the other members, when deficit, purchase capacity and energy services from Kentucky Power when it has surplus capacity and energy.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to pages 7-8 of the Pauley Testimony regarding the termination of pool agreement. Describe how this termination will affect energy costs to Kentucky Power.

RESPONSE

Energy costs will be impacted as shown on lines 2, 3, 11, 12, and 18 of RKW-Exhibit 4, page 1.

The termination of the Interconnection Agreement ("Pool") will result in Kentucky Power no longer making purchases of energy from other Pool members to satisfy Kentucky Power's load requirements. If replacement for this energy came from market purchases, it is anticipated that Kentucky Power's cost of energy would likely increase over the long term. By acquiring the energy instead from the proposed transfer of 50% of the two Mitchell baseload units, which will dispatch within operational constraints when their energy cost are less than market, Kentucky Power will benefit from this energy cost decrease relative to market.

Energy costs depend on a number of factors, however, in isolation, energy costs may increase somewhat since the primary energy purchases were from blend of various units from the other Pool members, including the Cook nuclear units. Mitchell is typical of the cost of energy that Kentucky Power currently purchases from Ohio Power.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

a. Refer to the Pauley Testimony, page 18-19, regarding the availability of the Mitchell units in 2015. Elaborate further on the statement that it would be unreasonable to expect AEP Generation Resources to delay the transfer of the interest of the Mitchell units to Kentucky Power until such time as Big Sandy Unit 2 is projected to be retired in June 2015.

b. Refer to the Pauley Testimony at page 18, line 14 to page 19, line 2. Describe what incremental cost in either capital or operating expenses Kentucky Power will incur due to transferring Mitchell in December 2013 when it is not needed until June 2015.

RESPONSE

a. Mitchell Units 1 and 2, which are currently Ohio Power Company assets, will be transferred to AEP Generation Resources Inc. on or about December 31, 2013. A 50% interest in these assets is being made available to KPCo at the same time and at the proposed price. AEP Generation Resources Inc. is a competitive business separate and distinct from AEP's operating companies. If the Mitchell units remain with AEP Generation Resources Inc. on January 1, 2014, then AEP Generation Resources Inc. will work to commit the units' output in the most economically attractive manner which could be a sale of the Mitchell units, a unit power sale from the Mitchell units, a long-term contract or other type of sale to a party other than KPCo. AEP Generation Resources Inc. has no obligation to hold the units and to transfer them to KPCo at a later date nor, if they are transferred, to transfer them at the proposed price at another time. KPCo recognizes that AEP Generation Resources Inc. has no such obligations and therefore concludes that it is unreasonable to expect that transfer of the units could occur at a later date on the terms that are being offered today.

b. The incremental costs of the Mitchell plant are the items shown on lines 17 through 20 of RKW-Exhibit 4. These costs may be off-set by incremental revenues or reduced purchased power expenses in the PJM market during the period from January 1, 2014 through May 31, 2015.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Case No. 2011-00401, Commission Staff's Third Request for Information, Item 13.b. which states, "20 percent of the Mitchell units would initially provide more than sufficient capacity to meet the required reserve margin under PJM's fixed resource requirement."

a. Confirm that this statement is correct as of February 2013.

b. If the answer to a. is yes, state whether owning 50 percent of the Mitchell Plant units and corresponding generation would provide Kentucky Power with more than sufficient capacity to meet the required reserve margin under PJM's fixed resource requirement after the retirement of both of the Big Sandy units.

c. If the answer to b. is no, explain what percentage of Mitchell Plant units' generation would meet the required reserve margin under PJM's fixed resource requirement.

RESPONSE

a. That statement is not correct as of February 2013 relative to the instant filing. The response offered in Case No. 2011-00401 was based on a view of Kentucky Power's generating resources that assumed the Big Sandy Unit 2 would continue to operate at 788 MW after being retrofitted with environmental controls; whereas the recommended option in this filing results in that unit being retired. Hence, not only would the amount/percentage of the Mitchell units necessary to transfer to Kentucky Power have to increase by 468 MW (from 20% to 50%... or, 30% x 1,560 MW total), but the Company would also be required to pursue an additional 250 MW of capacity resources to meet it's required reserve margin under PJM's fixed resource requirement. (See also "TABLE 1-4" from Company witness Weaver's direct testimony, Exhibit SCW-1). See also the Company's response to KPSC 1-57.

b. n/a

c. Please see the response to part a. above.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 12, line 16, of the Pauley Testimony, which refers to "a 30-year economic study period (2014 through 2040)." Confirm that the study period begins in 2011.

RESPONSE

Yes, the study period for the Strategist analysis begins in 2011.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 20, lines 3-4, of the Pauley Testimony.

a. What is the status of Kentucky Power's plans for the issuance of a Request for Proposal ("RFP") for 250 MW of long-term capacity and energy due to the anticipated retirement of Big Sandy unit 1?

b. Based on current plans, state when Kentucky Power anticipates receiving the bids in response to the RFP.

RESPONSE

a. The Company anticipates issuing the RFP in early March, 2013.

b. The Company has not completed the RFP, but preliminary plans are to allow 45 to 60 days for bidders to respond to the RFP. An additional 60 to 90 days will be needed for bid clarification, evaluation, and short listing.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 2, lines 19-20, of the Direct Testimony of Mark A. Becker ("Becker Testimony").

a. Identify the version of Ventyx's Strategist model that Kentucky Power used for its analysis.

b. State whether Kentucky Power modified, restricted or constrained the model for use in its analysis. If so, describe in detail the changes that Kentucky Power made and explain why the changes were made.

RESPONSE

a. Kentucky Power used Ventyx's Strategist Version 4.3.0

b. Kentucky Power did not modify, restrict, or constrain the Ventyx delivered model software.

WITNESS: Mark A Becker

Kentucky Power Company

REQUEST

Refer to page 3, lines 6-8, of the Becker Testimony.

a. Identify and describe the demand-side management programs Kentucky Power included in its Strategist analysis.

b. Provide the estimated impact on peak demand and energy requirements for each of the demand-side management programs.

RESPONSE

a. Strategist included impacts from energy efficiency programs, grid improvements (Volt VAR Optimization) and demand response.

Strategist requires a load shape to model energy efficiency impacts. Load shapes that precisely match the Company's programs are not practically available. Thus, KPCo uses end-use load shapes of commonly employed measures to effectively mimic the impacts from the energy efficiency programs that KPCo offers and expects to offer.

b. See KPSC 1-26 Attachment 1 for the impacts by program.

WITNESS: Mark A Becker

Energy Impact - Energy Efficiency and Grid Programs (GWh)

Year	VVO	Residential Heat	Residential Cool	Residential Lighting	Residential Other	Commercial Heat	Commercial Cool	Commercial Other	Industrial	Losses	Demand Response	Total
2012	-	3.4	1.1	7.8	1.7	0.3	0.2	3.2	-	1.5	-	19.2
2013	-	5.8	1.8	11.8	2.9	0.6	0.4	7.0	-	2.6	-	32.8
2014	-	7.9	2.4	14.0	3.9	0.9	0.6	10.3	-	3.4	-	43.4
2015	0.0	9.8	3.0	15.2	4.9	1.1	0.8	13.1	-	4.1	-	52.0
2016	17.8	11.5	3.6	15.6	5.8	1.4	0.9	15.4	-	4.6	-	76.5
2017	29.8	13.1	4.0	15.4	6.5	1.6	1.1	17.3	-	5.0	-	93.8
2018	34.4	14.4	4.5	14.9	7.2	1.7	1.2	18.8	-	5.3	-	102.3
2019	39.0	15.6	4.8	14.1	7.8	1.9	1.3	19.8	-	5.5	-	109.8
2020	43.6	16.6	5.1	13.3	8.3	2.0	1.4	20.6	-	5.7	-	116.5
2021	43.6	17.4	5.4	12.5	8.7	2.1	1.4	21.0	-	5.8	-	117.9
2022	43.6	18.1	5.6	11.7	9.1	2.2	1.5	21.2	-	5.9	-	118.8
2023	43.6	18.6	5.7	11.1	9.3	2.3	1.5	21.1	-	5.9	-	119.2
2024	43.6	19.0	5.9	10.5	9.5	2.3	1.6	20.9	-	5.9	-	119.2
2025	43.6	19.3	5.9	10.0	9.7	2.4	1.6	20.6	-	5.9	-	118.9
2026	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2027	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2028	43.5	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2029	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2030	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2031	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2032	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2033	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2034	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2035	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2036	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7
2037	43.5	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.6
2038	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.6
2039	43.5	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.6
2040	43.6	19.4	6.0	9.8	9.7	2.4	1.6	20.4	-	5.9	-	118.7

Peak Demand Impact - Energy Efficiency and Grid Programs (MW)

Year	VVO	Residential Heat	Residential Cool	Residential Lighting	Residential Other	Commercial Heat	Commercial Cool	Commercial Other	Industrial	Losses	Demand Response	Total
2012	0.0	0.0	0.5	1.1	0.3	0.0	0.2	0.1	0.0	0.3	3.7	6.2
2013	0.0	0.0	0.8	1.6	0.6	0.0	0.4	0.5	0.0	0.5	3.7	8.1
2014	0.0	0.0	1.2	1.9	0.9	0.0	0.5	0.9	0.0	0.7	10.5	16.6
2015	0.0	0.0	1.4	2.1	1.1	0.0	0.7	1.4	0.0	0.8	17.5	25.0
2016	3.5	0.0	1.7	2.1	1.4	0.0	0.8	1.8	0.0	0.9	26.3	38.5
2017	5.8	0.0	1.9	2.1	1.6	0.0	0.9	2.2	0.0	1.0	35.0	50.5
2018	6.7	0.0	2.1	2.0	1.8	0.0	1.0	2.6	0.0	1.1	35.7	53.0
2019	7.6	0.0	2.3	1.9	2.0	0.0	1.1	2.9	0.0	1.1	36.4	55.3
2020	8.6	0.0	2.4	1.8	2.1	0.0	1.2	3.1	0.0	1.1	37.1	57.5
2021	8.6	0.0	2.6	1.7	2.3	0.0	1.3	3.3	0.0	1.2	37.9	58.7
2022	8.6	0.0	2.7	1.6	2.4	0.0	1.3	3.4	0.0	1.2	38.6	59.8
2023	8.6	0.0	2.7	1.5	2.4	0.0	1.4	3.5	0.0	1.2	39.4	60.7
2024	8.6	0.0	2.8	1.4	2.5	0.0	1.4	3.5	0.0	1.2	40.2	61.6
2025	8.7	0.0	2.8	1.4	2.5	0.0	1.4	3.5	0.0	1.2	41.0	62.5
2026	8.7	0.0	2.8	1.3	2.6	0.0	1.4	3.5	0.0	1.2	41.0	62.5
2027	8.7	0.0	2.8	1.3	2.6	0.0	1.4	3.5	0.0	1.2	41.0	62.5
2028	8.7	0.0	2.8	1.3	2.6	0.0	1.4	3.5	0.0	1.2	41.0	62.5
2029	8.7	0.0	2.8	1.3	2.5	0.0	1.4	3.5	0.0	1.2	41.0	62.5
2030	8.7	0.0	2.8	1.3	2.6	0.0	1.4	3.5	0.0	1.2	41.0	62.5
2031	8.7	0.0	2.8	1.3	2.6	0.0	1.4	3.5	0.0	1.2	41.0	62.6
2032	8.7	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.7
2033	8.8	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.9
2034	8.8	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.8
2035	8.8	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.8
2036	8.8	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.8
2037	8.8	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.8
2038	8.9	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	63.0
2039	8.9	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	63.0
2040	8.8	0.0	2.8	1.3	2.7	0.0	1.4	3.6	0.0	1.2	41.0	62.8

Kentucky Power Company

REQUEST

Refer to page 6, lines 13-14, of the Becker Testimony, which state, "Strategist® was used to perform the economic evaluation of the Big Sandy emission retrofit and other alternative options in Case No. 2011-00401."

a. State whether Kentucky Power performed an economic evaluation, using the Strategist model, on the impact of the Mitchell Plant units if Kentucky Power were to acquire more than the proposed 50 percent undivided interest in the units. If the answer is yes, provide the results. If no, explain why such an analysis was not performed.

b. State whether Kentucky Power performed an economic evaluation, using the Strategist model, assuming that Kentucky Power would acquire a 250 MW undivided interest in the Dresden or Waterford generating plants along with the proposed 50 percent undivided interest in the Mitchell Plant units. If yes, provide the results. If no, explain why such an analysis was not performed.

c. Provide the sequence and a time line of events that led to Kentucky Power's decision not to construct a Dry Flue Gas Desulfurization ("DFGD") on the Big Sandy Unit 2. Include in the response a time line of when the decision not to construct the DFGD was made, and also identify by whom, and whether it was a board, committee, or informal group that made the decision.

RESPONSE

a. No Strategist analysis was performed to evaluate more than a 50% interest in the Mitchell Plant for Kentucky Power. There was not more than a 50% undivided interest in the Mitchell Plant made available to Kentucky Power.

b. No Strategist analysis was performed to evaluate the acquisition of a 250 MW interest in Dresden or Waterford. Neither the Dresden nor Waterford plants were options made available to Kentucky Power. Please see the Company's response to SC 1-6.

c. May 30th/31st, 2012 - The Company requested and was granted leave by the Commission to withdraw the DFGD application in Case No. 2011-00401.

June - August 2012 - The Company began reviewing options to meet the Company's obligation under the Consent Decree, the Cross State Air Pollution Rule, the Mercury and Air Toxic Standard Rule, and other environmental standards.

August/September 2012 - Decision was made to proceed with a FERC and State filing, subject to later validation, to transfer a 50% interest in the Mitchell units based upon indications that the Mitchell transfer was the least cost alternative.

November 2012 - After receiving the final analysis which indicated the Mitchell transfer was the least cost alternative, the decision was made to file with the KPSC for a 50% interest in the Mitchell units and retire Big Sandy Unit 2. This decision was made by an informal group of KPCo/AEP management individuals listed in response to SC 1-4.

WITNESS: Mark A Becker/Gregory G Pauley

Kentucky Power Company

REQUEST

Refer to page 7, lines 22-24, of the Becker Testimony.

a. Provide Kentucky Power's weighted average cost of capital as of December 31, 2011.

b. State whether the weighted average cost of capital changed from the previous year, and if so, from what level.

RESPONSE

a. Please see page 2 of this response for Kentucky Power's weighted average cost of capital as of December 31, 2011.

b. The weighted average cost of capital did change from the previous year due to the change in the cost percent rate for Accounts Receivable Financing. Please see page 3 of this response for a copy of the 2010 weighted average cost of capital.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Cost of Capital
As of December 31, 2011

Ln No (1)	Description (2)	Capital (3)		Percent of Total (4)	Cost Percentage Rate (5)	Weighted Average Cost Percent (6)=(4)x(5)
1	Long Term Debt	$550,000,000	a	51.608%	6.48%	3.35%
2	Short Term Debt	$0	a	0.000%	0.38% b	0.00%
3	Accts Receivable Financing	$55,306,695		5.190%	1.14%	0.06%
4	Common Equity	$460,415,218	a	43.202%	10.50%	4.54%
5	Total	$1,065,721,913		100.000%		7.95%

a Book balance as of 12/31/2011
b Average borrowing costs for the 12 Months Ended December 31, 2011

Kentucky Power Company
Cost of Capital
As of December 31, 2010

Ln No (1)	Description (2)	Capital (3)		Percent of Total (4)	Cost Percentage Rate (5)	Weighted Average Cost Percent (6)=(4)x(5)
1	Long Term Debt	$550,000,000	a	52.963%	6.48%	3.43%
2	Short Term Debt	$0	a	0.000%	0.38% b	0.00%
3	Accts Receivable Financing	$42,242,695		4.068%	1.21%	0.05%
4	Common Equity	$446,215,385	a	42.969%	10.50%	4.51%
5	Total	$1,038,458,080		100.000%		7.99%

a Book balance as of 12/31/2010
b Average borrowing costs for the 12 Months Ended December 31, 2010

Kentucky Power Company

REQUEST

Refer to page 8, lines 3-4, of the Becker Testimony. Provide the long-term commodity pricing forecasts prepared by American Electric Power Service Corporation's Fundamental Analysis department and the forecasted load for Kentucky Power over the analysis period.

RESPONSE

Please see files on the enclosed CD named KPC2.TXT;
Price_Forecast_Nominal_FTCA_CSAPR_2011_09_23.xlsx;
Price_Forecast_Nominal_FTCA_CSAPR_EarlyCarbon_2011_10_10.xlsx;
Price_Forecast_Nominal_FTCA_CSAPR_High_2011_10_14.xlsx;
Price_Forecast_Nominal_FTCA_CSAPR_Low_2011_10_14.xlsx; and
Price_Forecast_Nominal_FTCA_CSAPR_NoCarbon_2011_10_04.xlsx.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to page 3, lines 7-19, of the Direct Testimony of Karl R. Bletzacker ("Bletzacker Testimony"). Provide the actual values used for the nine forecasts mentioned in lines 13-19 for each year in the analysis. Provide the forecasts in electronic Excel spreadsheet format with formulas intact and cells unprotected.

RESPONSE

Please refer to KPCO 2012-00578 PSC 1-30 Nominal.xls and KPCO 2012-00578 PSC 1-30 Real.xls on the enclosed CD.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to page 4, lines 3-6, of the Bletzacker Testimony.

a. Discuss the methodology that Kentucky Power used to develop the forecasts used in its analysis for each of the following:

(1) Natural gas prices;
(2) CO2 prices;
(3) Coal prices in the Northern and Central Appalachian regions; and
(4) On- and Off-peak energy prices and capacity values within the PJM-RTP RPM construct.

b. Provide a detailed explanation of how the ranges (high, base and low) for the forecasted values recommended by the Fundamentals Analysis group for use in Kentucky Power's analysis were determined.

c. Provide any narrative or documentation that supports the forecasts and further explains the basis for the forecasted values.

d. Identify all source documents the Fundamentals Analysis group relied on to develop its forecasts, including information and forecasts provided by Cambridge Energy Research Associates, PIRA and WoodMackenzie. Indicate date of forecast and provide the forecasts in an electronic Excel spreadsheet format with formulas intact and cells unprotected.

e. State when each of these forecasts was last updated prior to inclusion in the analysis.

f. State whether any of the forecasts were updated subsequent to the analysis. If so, provide the updated forecasts in electronic Excel spreadsheet format with formulas intact and cells unprotected.

g. Provide documentation of the process that AEP's Fundamentals Analysis group uses to develop, update, and approve its forecasts.

RESPONSE

a. The Company's process of Long-Term Forecast development is initiated when there are substantive changes in key drivers of the existing forecast. In addition to reviewing research papers provided by third-party consultants, the investment community, industry groups, trade press and governmental agencies, discussions are held with internal subject-matter experts on the topics of environmental policy, renewables, load, economic indicators, generation costs, fuels and transmission to discuss the changes in the drivers. Using professional judgment, forecasts are updated and then re-presented to internal subject-matter experts prior to inclusion in the iterative AuroraXMP modeling process. Finally, the entire suite of inputs and outputs is presented internally for approval.

Key drivers for natural gas, CO2, coal and energy prices include:

(1) Natural gas prices; Bletzacker Direct Testimony at pages 6 to 10 addresses major natural gas price driving forces.

(2) CO2 prices; Bletzacker Direct Testimony at pages 10 to 12 addresses implementation timing and the application of allowance prices as modeled.

(3) Coal prices in the Northern and Central Appalachian region are projected to be strongly influenced by the following driving forces.

<u>Strict regulations on environment and safety</u>: The U.S. EPA began implementation of strict water quality standards for coal mining, especially for mountaintop removal mining practices. Currently, approximately half of the coal production in Central Appalachia (CAPP) comes from surface mines and may be affected by EPA regulations. Since the April 2010 Upper Big Branch mine disaster, the Mine Safety and Health Administration (MSHA) has further tightened mining safety regulations for underground mining.

<u>Competition from natural gas:</u> The development of shale gas extraction technology unlocks abundant natural gas. Coal-to-natural gas switching for power generation dampens the electric power sector coal demand, especially in the U.S. southeast, where delivered coal prices were already high due to elevated transportation costs.

<u>Massive retirement of coal-fired plants</u>: Domestic coal demand is projected to decline after massive coal-fired plant retirement due to implementation of MATS. Currently, the U.S. power sector consumes more than 90% of coal produced, and massive coal plant retirement dampens coal demand significantly. Lower demand puts downward pressure on coal prices. Environmental controls installed to comply with MATS will increase coal plant fuel flexibility, and lessen the demand for CAPP.

<u>Elevated U.S. coal exports</u>: Demand for coal in global markets, especially in the Asian market for both metallurgical and thermal coal is projected to strengthen.

(4) On- and off-peak energy prices and capacity values within PJM; These values for PJM and the rest of North America are discrete outputs of the AuroraXMP model.

b. To capture a low and a high case, a statistical distribution analysis was used. Five years of gas rice and coal price history were used to compute one standard deviation from the mean. Plausible cases were built around these high and low fossil fuel prices. Additionally, a "no CO2" and an accelerated CO2 implementation (2017) were created to frame these uncertainties.

c. Pleases refer to "a." above and "g." below.

d. Sources of research information include:

Investment Community - Equity and fixed Income analysts
Third-Party Consultants - IHS CERA, PIRA, WoodMackenzie
Industry Groups - Edison Electric Institute
Government Agencies - EPA, DOE, NERC, FERC
Trade Press - Argus Air Daily, Coal Daily, Coal Weekly, The Energy Daily, Megawatt Daily, Gas Daily
Various Stakeholders - Independent System Operators, Interest Groups (Environmental and Industry)
Energy Companies - Listen to earnings calls, press releases, SEC filings, etc
Internal Information - Experience from other organizations within the company.
Independent Studies - Proprietary research studies

Pursuant to licensing provisions, CERA, PIRA and WoodMackenzie and certain Trade Press information and forecasts cannot be distributed to non-licenses.

e. The forecasts described in "a." above are reviewed contemporaneously with the final analysis.

f. There have been no formal updates to the forecasts in "a." above since the time these forecasts were incorporated in the final analysis.

g. Please refer to the Company's response to subpart a above. There is no formal documentation of the process used by AEP's Fundamentals Analysis Group to develop, update and approve its forecasts.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to pages 6 and 7 of the Bletzacker Testimony, regarding Kentucky Power's long-term outlook for natural gas. Provide support for the statements that the environmental impacts of shale gas development will ultimately be manageable and that the domestic natural transportation gas infrastructure is sufficiently robust to overcome any potential constraints due to increased demand for natural gas.

RESPONSE

The Company's natural gas price forecast assumes that the environmental impacts of shale gas development will ultimately be manageable. This assumption is consistent with information available from the Energy Information Administration (EIA), which forecasts as of 2012 that shale gas will become the majority of the United States domestic supply of natural gas by 2030.

WITNESS: Karl R Bletzacker

Kentucky Power Company

REQUEST

Refer to page 3, lines 11-14, of the Direct Testimony of Jeffrey D. LaFleur ("LaFleur Testimony"). Provide the following operational data for the Mitchell Plant Units 1 and 2 for the past five years:

a. Heat Rate (btu/kwh);

b. Capacity Factor;

c. Equivalent Forced Outage Rate (EFOR);

d. An outline of major availability detractors;

e. Recent boiler condition assessments;

f. Recent turbine/generator overhauls and assessments;

g. Recent high energy piping assessments; and

a. Recent plant life assessment reports.

RESPONSE

a/b. Please refer to the Company's response in Staff 1-33_Confidential Attachment 1.

c. Please see the table below for the Mitchell Units 1 and 2 equivalent forced outage rate (EFOR) for 2008-2012.

Equivalent Forced Outage Rate (EFOR) (%)

	ML1	ML2
2008	12.35	6.92
2009	5.63	3.17
2010	10.58	8.04
2011	11.79	9.83
2012	13.14	7.86

d. Refer to 'Staff 1-33 Attachment 2' for the top three contributors to EFOR by year for Mitchell Units 1 and 2.

e. Ohio Power, as the Engineer of Record and Operator of the Mitchell Plant, with assistance from AEPSC, continually monitors and maintains the plant's equipment, including some replacements when and where necessary. AEP operating companies, including Ohio Power, monitor the major components of their generating units, and utilize preventative and predictive maintenance, consistent with good utility practice, to replace or repair equipment as necessary. Preventative and predictive maintenance procedures are reviewed and recommended by AEPSC's Engineering Department, and any issues or solutions are discussed with Management Please see Staff 1-33 Attachments 3 through 16 for reports.

WITNESS: Jeffery D LaFleur

33a. Heat Rate (BTU/KWh)

	ML1	ML2
2008	[redacted]	
2009		
2010		
2011		
2012		

33b. Net Capacity Factor MWh (%)

	ML1	ML2
2008	[redacted]	
2009		
2010		
2011		
2012		

Mitchell 1

2012

Cause Code Description	EFOR %	General Description
Buckets or Blades	2.660	LP Turbine Blade Failure
SCR NOx Injection grid piping/valves	2.112	High Trona Grid Temperatures, Air Heater Deterioration
Startup bypass tanks or flash tanks	1.447	Steam leak upstream of URV-254

2011

Cause Code Description	EFOR %	General Description
Intercept valves	2.936	Broken intercept valve stem
Air heater (regenerative)	1.748	#11 air heater locked up
Miscellaneous turbine piping	1.603	Steam leak on turbine steam chest

2010

Cause Code Description	EFOR %	General Description
Economizer	2.337	Tube leak, 1 occurrence
Induced draft fans	1.752	Approaching stall margin. > 75 occurrences, possibly air heater or Trona pluggage
Feedwater pump	1.358	Feedpump vibration

2009

Cause Code Description	EFOR %	General Description
Water wall (furnace wall)	3.183	Tube leak, 2 occurrences
Primary air fan	0.496	#12 Primary Air Fan repairs
Pulverizer inspection	0.393	Pulverizer Inspections

2008

Cause Code Description	EFOR %	General Description
Flue gas ducts (except recirculation)	6.311	Outlet duct pressure limitation, duct stiffener design issue
Economizer	1.648	Tube leak, 2 occurrences
Miscellaneous turbine piping	1.251	Turbine drain line leak

Mitchell 2

2012

Cause Code Description	EFOR %	General Description
Economizer	3.174	Economizer Tube Leaks
Miscellaneous Turbine Piping, Other High Pressure Turbine Problems	1.492	Turbine SV Above Seat Drain Line leak, multiple occurrences
Air Heater	0.465	Air Heater Problems (Differential, Coupling Failure, etc)

2011

Cause Code Description	EFOR %	General Description
Feedwater Pump	3.201	BFP Failure
Economizer	2.405	Economizer Tube Leaks
Miscellaneous Turbine Piping	0.850	Line blew off DMO-3, one occurrence

2010

Cause Code Description	EFOR %	General Description
First Reheater	2.692	Tube Leak, 2 occurrences
Reheat steam relief/safety valves	2.122	Roof outlet heater safety valve vent stack failure
Other boiler tube leaks	0.790	Boiler tube leak indications

2009

Cause Code Description	EFOR %	General Description
Economizer	1.421	Tube Leak
Feedwater pump drive - steam turbine, Other FW pump problems	0.678	FPT Valves Wide Open
Coal conveyors and feeders	0.211	Coal Conveyor issues

2008

Cause Code Description	EFOR %	General Description
Economizer	2.107	Tube Leaks, 2 occurrences
Second reheater	1.396	Tube Leak, 1 occurrence
First reheater	1.288	Tube Leak, 1 occurrence

Kentucky Power Company

REQUEST

Refer to page 3, line 19, to page 4, line 1, of the LaFleur Testimony which states, "[U]nits 1 and 2 were retrofitted in 2007 with state-of-the-art environmental pollution controls in the form of a Flue Gas Desulfurization ("FGD") system for sulfur dioxide ("SO2") emissions reduction and a Selective Catalytic Reduction ("SCR") system for nitrogen oxides emissions reductions."

a. Provide the year the FGD and SCR analysis for the Mitchell Plant Units 1 and 2 was initiated.

b. Provide the in-service dates for the Mitchell Plant Units 1 and 2 FGDs.

c. Provide the year when the FGD and SCR analysis for AEP's Amos Plant Units 1 and 2 was initiated.

d. Provide the in-service dates for the Amos Plant Units 1 and 2 FGD and SCR.

e. Provide the date that precipitators were installed and state whether any studies were conducted on their capability going forward or in consideration of replacement with bag house technology.

RESPONSE

a. The flue gas desulfurization (FGD) system analyses were initiated in 2003 and the selective catalytic reduction (SCR) system analyses were initiated in 2001 for Mitchell Units 1 and 2.

Kentucky Power Company

b. The FGD system for Mitchell Unit 2 was placed in-service in January 2007 and the FGD system for Mitchell Unit 1 was placed in-service in April 2007.

c. The FGD system analyses were initiated in 2004 and the selective catalytic reduction (SCR) system analyses were initiated in 2000 for AEP's Amos Units 1 and 2.

d. The FGD system for Amos Unit 1 was placed in-service in January 2011 and the FGD system for Amos Unit 2 was placed in-service in March 2010.

e. The Mitchell Units 1 and 2 precipitators were installed in 1978. The Company did conduct a study to determine the precipitators capability going forward. The need for baghouse technology was also evaluated, but it was determined that a baghouse is not needed.

WITNESS: Jeffery D LaFleur

Kentucky Power Company

REQUEST

Refer to page 5, lines 16-17, of the LaFleur Testimony, which state, "[H]owever, unlike the Mitchell and Amos units, Big Sandy Unit 2 is not retrofitted with a FGD system."

a. Explain why Big Sandy Unit 2 was not retrofitted with a FGD system at the time the Mitchell and Amos units were retrofitted.

b. State whether the in-service cost for a Big Sandy Unit 2 FGD would have been reasonably comparable to the Mitchell FGD in-service costs if the Big Sandy Unit 2 FGD had been installed in 2007, at the same time as the Mitchell Plant units were retrofitted. Take into consideration that Big Sandy Unit 2 and the Mitchell units are of similar design and nominal generating capacity. If the costs would not have been reasonably comparable, explain why.

RESPONSE

a. As part of the Clean Air Interstate Rule (CAIR) compliance strategy, AEP Service Corporation began preliminary Phase I feasibility analyses on Big Sandy 2 in 3Q of 2004 for the retrofit of a FGD. After preliminary feasibility studies, conceptual engineering, and a competitive selection of a FGD Original Equipment Manufacturer, the Phase I activities were suspended in 2Q of 2006. A refined assessment indicated that the costs to retrofit Big Sandy 2 had increased substantially. Also, there was a decrease in the projected price spread between low and high sulfur coals that effectively eliminated any fuel savings associated with using a higher sulfur coal, further making the retrofit less attractive.

b. No; the in-service cost for a Big Sandy Unit 2 FGD would not have been reasonably comparable to the Mitchell FGD in-service costs if the Big Sandy Unit 2 FGD had been installed in 2007, at the same time as the Mitchell Plant units were retrofitted. The Mitchell units were more economical to scrub based largely on the lower projected fuel costs attributed to their proximity to the low cost, high sulfur coal mines and lower transportation rates as compared to Big Sandy. In addition, Mitchell Units 1 and 2 are dual 800 MW units that can share common equipment, reducing costs as compared to BS2, a single 800MW unit.

WITNESS: Jeffery D LaFleur

Kentucky Power Company

REQUEST

Refer to page 3, line 9, to page 4, line 4, of the Direct Testimony of Karl A. McDermott ("McDermott Testimony"), which states:

After reviewing the regulatory environment in Kentucky and the asset transfer proposal, I conclude that:

1. Kentucky Power's Proposal is the least-cost combination of feasible and reasonable options available to meet its future obligations to customers.

2. The Proposal represents a flexible portfolio that includes employing market forces for a smaller amount of supply (250 MW) which the markets have greater capability of meeting in a cost effective manner.

3. The Proposal will allow Kentucky Power to eliminate the need to retrofit Big Sandy 2, which will avoid significant capital investments and the consequent rate impacts associate with those expenses.

4. It is unnecessary for Kentucky Power to conduct a full RFP process since the analysis conducted by the Company includes evaluations that approximate price bids that would result from an RFP process.

5. The Proposal maintains the Commission's regulatory and rate authority over an owned asset.

   a. If Kentucky Power eventually takes ownership of the generating assets associated with the conclusion drawn in number 2 above, state whether that would increase or decrease the Commission's regulatory and rate authority over an owned asset.

   b. If Kentucky Power eventually takes ownership of the generating assets associated with the conclusion drawn in number 2 above, state whether that would tend to increase or decrease the stability of the rates Kentucky Power's customers would pay.

Kentucky Power Company

c. If Kentucky Power eventually takes ownership of the generating assets associated with the conclusion drawn in number 2 above, state whether all of the other conclusions would remain the same as long as the cost of the 250 MW is equal to or less than the market price.

d. If the answer to part c. is no, explain why.

RESPONSE

a. Dr. McDermott's opinion is that the specific conclusion drawn in number 2 does not affect the Commission's regulatory and rate authority over a utility owned asset.

b. Dr. McDermott believes that a flexible portfolio approach to resource acquisition tends to promote stability in rates relative to the alternative.

c. It depends. Conclusions 3 ,4 and 5 would not change. Conclusion 1 and 2 could change.

d. Because conditions may change over time, it may be that least cost solutions could change over time and that may change Dr. McDermott's conclusions in 1 and 2. Least cost in this context is based on the then current <u>expected</u> costs of resources under review, given that the Company must plan to meet its load going-forward based on the best information available at the time the decision is made. As the future unfolds and more information becomes available or as other factors change (e.g., natural gas prices, industry and firm organizational changes, technology and demand change, etc.) least cost options may change and that could change Dr. McDermott's conclusions, even if the RFP for the 250 MW comes in at or below the expected market price. For example, future technical change may dictate that Kentucky Power Company build a unit to meet new load rather than undertake the 250 MW purchase.

WITNESS: Karl A. McDermott

Kentucky Power Company

REQUEST

Refer to page 7, lines 7-11, of the McDermott Testimony.

a. State whether Mr. McDermott would agree that the list of alternatives should also include existing generating assets in the region.

b. State whether Mr. McDermott is familiar with the Riverside Generating assets in eastern Kentucky.

RESPONSE

a. If those alternatives are feasible (e.g., there is transmission access or transmission access can be acquired at a reasonable cost and the asset is expected to be reliable over the long term), and are comparable assets (base load units), and reasonably expected to be available (either through an RFP process or other market process, or if the physical resources are known to be available for purchase), Dr. McDermott would agree that such alternatives should be explored.

b. Yes, Dr. McDermott is aware that such assets exist.

WITNESS: Karl McDermott

Kentucky Power Company

REQUEST

Refer to page 9, line 1, of the McDermott Testimony. State whether the choice of options should also consider socio-economic impacts in the utility service area.

RESPONSE

Dr. McDermott's opinion is that the social effects of economic choices should be considered in the context of the total costs and benefits of a proposed action, subject to the issues he raised in his testimony at page 9 lines 2-15, and further subject to the statutes, rules, and Commission decisions that govern this proceeding before the Kentucky Public Service Commission.

WITNESS: Karl McDermott

Kentucky Power Company

REQUEST

Refer to pages 11-12 of the McDermott Testimony and pages 36-38 of the Direct Testimony of Scott C. Weaver ("Weaver Testimony") in which the witnesses discuss the fact that Kentucky Power did not issue a RFP as part of its consideration and evaluation of options for replacement capacity and energy.

a. The testimonies reference existing plant(s) within PJM in discussing what might be offered as a result of issuing an RFP. State whether there would be reasons for limiting potential bids/offers to sources within PJM.

b. The testimonies reference gas-fired capacity (McDermott) and combined cycle ("CC") assets (Weaver) as the generation source that would most likely be offered, or available, as a result of an RFP solicitation. Given the availability of the Mitchell capacity at this time, explain how confident Kentucky Power and AEP are that other, non-AEP coal-fired capacity might be available in response to an RFP.

RESPONSE

a. Although there is no physical or technical reason for limiting potential bids to sources within PJM, from a practical standpoint, energy and capacity would have to be deliverable to the PJM network. Therefore, any potential source outside of PJM would have an added expense of obtaining firm transmission capacity.

b. Although it is possible that non-AEP coal-fired capacity may be available in response to an RFP, the analysis performed by Mr. Weaver, as corroborated by the testimony of Dr. McDermott, would indicate that any such offer received in response to an RFP would approach a projected PJM market price which was determined to be more costly than the asset transfer option put forth by the Company.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to pages 11-12 and page 13, lines 1-4, of the McDermott Testimony. The testimony at page 11 indicates that it was not necessary for Kentucky Power to issue an RFP and competitively bid its resource needs, but the testimony at page 13 states that the Commission should use RFPs "for power procurement." Explain the apparent dichotomy in the testimony.

RESPONSE

The references cited relate to two different topics. At pages 11-12 Dr. McDermott is referring to the use of RFPs for <u>all</u> necessary resources (i.e., an RFP that would presumably attempt to benchmark the purchase price of the 50% transfer of the Mitchell unit). At page 13, Dr. McDermott is referencing the fact that the Proposal includes an RFP for 250 MW.

WITNESS: Karl McDermott

Kentucky Power Company

REQUEST

Refer to page 10, lines 22-23, and page 11, lines 1-2, of the Direct Testimony of John M. McManus ("McManus Testimony").

a. Provide details of any modifications that have been implemented or are planned to be implemented to bring the Mitchell Plant Units 1 and 2 into compliance with the December 2011 EPA Mercury and Air Toxics Standard ("MATS").

b. Provide cost estimates for any modifications to enable the Mitchell Units to comply with MATS.

c. Provide the expected schedule required to implement MATS compliance projects associated with the Mitchell Unit.

RESPONSE

a. The Mitchell Plant is expected to be able to achieve the MATS limits with the current emissions control system. No modifications to these systems have been implemented or are planned to bring the units into compliance.

b & c. See response to part a.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 11, lines 4-6 of the McManus Testimony.

a. Provide details of any modifications that have been implemented or are planned be implemented to bring the Mitchell Units 1 and 2 into compliance with the December 2012 EPA National Ambient Air Quality Standard ("NAAQS") as associated with Particulate Matter 2.5 (PM2.5) with limitation to a flue gas concentration of 12ug/m3.

b. Provide cost estimates for any modifications to enable the Mitchell Units to comply with the latest NAAQS.

c. Provide the expected schedule required to implement associated Mitchell Unit's NAAQS compliance projects. Refer to page 11, lines 4-6 of the McManus Testimony.

RESPONSE

a. The process of implementing the December 2012 PM2.5 NAAQS will take several years as the West Virginia DEQ, with subsequent approval by EPA, must determine areas that do not meet the standard and then must develop a plan to bring those areas into attainment. It is not known if, when, or how the Mitchell Plant may be impacted. As such, no related modifications have been implemented or are planned.

b & c. See response to Part a.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the McManus Testimony, page 11, lines 17 through 19.

a. Provide details of any modifications that have been implemented or are planned be implemented to bring the Mitchell Plant Units 1 and 2 into compliance with the pending EPA Clean Water Act 316b cooling water intake regulations.

b. Provide cost estimates for any modifications to enable the Mitchell Units to comply with pending EPA Clean Water Act 316b cooling water intake regulations.

c. Provide the expected schedule required to implement pending EPA Clean Water Act 316b cooling water intake regulations for the Mitchell Plant units.

RESPONSE

a. EPA is expected to promulgate the final 316(b) rule on or before June 27, 2013. The Mitchell units are currently equipped with closed-cycle cooling systems. As such the requirements in the proposed rule were not expected to have a significant impact. It is anticipated that an upgrade to the cooling water intake screens at the Mitchell plant may be required; however, the specifics of any upgrade will depend on the final rule.

b. Please refer to Company witness Weaver's Exhibit SCW-4 for an estimate of the costs necessary to comply with the proposed 316(b) Rule for the Mitchell Units 1 and 2.

c. The schedule to implement the proposed EPA Clean Water Act 316b regulations is expected in the finalized rule on or before June 27, 2013. In the proposed rule, EPA indicated that implementation would be "as soon as possible but within 8 years at the latest."
(http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/upload/qa_proposed.pdf)

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to the McManus Testimony. State whether the Mitchell Plant Units meet the requirements of the recently issued final rule for particulate matter that reduced the standard from 15 ug/m3 to 12 ug/m3. If not, provide the estimated increases in capital and operating expenses required for compliance.

RESPONSE

The process of implementing the December 2012 PM2.5 NAAQS will take several years as the West Virginia DEQ, with subsequent approval by EPA, must determine areas that do not meet the standard and then must develop a plan to bring those areas into attainment. It is not known if, when, or how the Mitchell Plant may be impacted. As such, no related capital or operating expenses have been estimated.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Refer to page 4, lines 13-16, of the Weaver Testimony, which states, "[A]s will be discussed, this testimony will serve both to re-analyze all of the unit disposition options previously evaluated in Case No. 2011-00401 utilizing more up-to-date information, and introduce the results of economic modeling performed to assess additional options now available to KPCo."

a. State whether Mr. Weaver or anyone else at American Electric Power Service Corporation ("AEPSC") or Kentucky Power performed any analysis other than that involving the options filed in this proceeding. If yes, provide a description of the analysis and the results of the analysis.

b. State whether Mr. Weaver or anyone else at AEPSC or Kentucky Power performed any analysis in which Kentucky Power would have an undivided ownership share of the Mitchell Plant greater or less than the 50 percent being proposed in this proceeding. If yes, provide the results along with the analysis.

c. State whether Mr. Weaver or anyone else at AEPSC or Kentucky Power performed any analysis in which Kentucky Power would have an undivided ownership in any other Ohio Power generating facilities along with its undivided 50 percent ownership share of the Mitchell Plant. If yes, provide the results along with the analysis.

RESPONSE

a. No other analysis beyond the options filed in this proceeding were performed by Mr. Weaver or anyone else at AEPSC or Kentucky Power.

b. Yes, Kentucky Power performed analyses for this proceeding in which Kentucky Power would have an undivided ownership share of the Mitchell Plant less than 50 percent ownership. Please see Exhibit SCW-2, Options 1A, 2A, and 3A (20% Mitchell Asset Transfer options) and the supporting detail offered in response to Commission Staff 1-1. Note Options 5A and 6 were the 50% Mitchell Asset Transfer options. No other ownership options were modeled.

c. No, neither Mr. Weaver nor anyone else at AEPSC or Kentucky Power performed any analysis for this proceeding in which Kentucky Power would have an undivided ownership in any other Ohio Power generating facility along with its undivided 50 percent ownership share of Mitchell Plant.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 5, lines 11-14, of the Weaver Testimony, which state:

As summarized on SCW- Exhibit 2 and on the following TABLE 1, eleven (11) unique variations involving six (6) alternative options were assumed to be available to KPCo to address the unit disposition decisions facing both Big Sandy Units 1 and 2, including the prospect of a specific affiliate asset transfer…

Also refer to page 1 of Exhibit(s) SCW-5A to SCW-5E. The cumulative present worth of Option #5A in each scenario is a negative number or a savings as shown in the table below.

Option #5A : Big Sandy Unit 1 Gas Conversion (07/2015); Retire Big Sandy Unit 2 (06/2015); Mitchell Plant Unit 1 & 2 Transfer (01/2014); No Big Sandy Plant Replace-Rebuild Capacity at Generic Site; and No Market Purchase Duration

Exhibits	Cumulative Present Worth ($000)
Exhibit SCW-5A, Page 1 of 2 Base Pricing	($156,437)
Exhibit SCW-5B, Page 1 of 2 Higher Band Pricing	($149,439)
Exhibit SCW-5C, Page 1 of 2 Lower Band Pricing	($153,970)
Exhibit SCW-5D, Page 1 of 2 No Carbon Pricing	($168,178)
Exhibit SCW-5E, Page 1 of 2 Early Carbon Pricing	($144,386)

a. Although Option #6 may be the option proposed in this proceeding, state whether Option #5A may ultimately become the option that Kentucky Power will consider in meeting its load requirement to meet its native load to serve its customers.

b. Identify all other alternatives Kentucky Power considered for inclusion in its analyses but elected to exclude.

RESPONSE

a. Option #5A may ultimately be selected as the option the Company will follow in meeting its PJM resource requirements, if the Big Sandy 1 --converted as a natural gas-fired steam unit-- is determined to be more favorable than other market-based resources to be offered through the proposed RFP.

b. No other alternatives considered for inclusion in these analyses were excluded by the Company.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 8, lines 7-21, of the Weaver Testimony, where it states:
As summarized 011 SCW- Exhibit 2, Options #1B, #2B, #3B, #4A and #4B are largely identical to the disposition alternatives evaluated in Case No. 2011-00401. The only meaningful differences within this re-analysis for those options are:

The recognized delay in the in-service dates for the Option #I DFGD retrofit to June 2017 (from June 2016); along with the attendant cost increases associated with that change.

Likewise, the delay in the estimated in-service date of the replacement CC options (Options #2 and #3) to the same June 2017 timeframe, along with the attendant cost estimate modifications.

The further recognition that such in-service delays would result in the need to rely solely on PJM market capacity and energy in the period post-unit retirements (June 2015 or April 2016, depending on the option and unit), until the 'build' option is completed in June 2017 (Options #1, #2, and #3).

Options #1A, #2A, #3A, #5A, #5B and #6 represent alternative disposition options associated with this filing. Each of these new options offers variations as to the extent/level of an affiliate generating asset transfer from a portion of the Mitchell facility.

a. Provide the cost increase associated with the delay in the in-service date of the DFGD retrofit from June 2016 to June 2017.

b. State whether Kentucky Power agrees that the cost increase associated with the delay in the in-service date for the DFGD was a direct result of it voluntarily withdrawing its proposal in Case No. 2011-00401. (3 See footnote below)

c. Provide the amount of the cost increase associated with the delay in the in-service date of the replacement CC options (Options #2 and #3) to the same June 2017 timeframe.

d. State whether Kentucky Power agrees that the cost increase associated with the delay in the estimated in-service date of the replacement CC options was a direct result of

Kentucky Power Company

Kentucky Power's voluntarily withdrawing its proposal in Case No. 2011-00401.(4 See footnote below)

e. Provide the potential cost associated with the recognition that such in-service delays would result in the need to rely solely on PJM market capacity and energy in the period post-unit retirements (June 2015 or April 2016, depending on the option and unit).

f. State whether Kentucky Power agrees that the cost associated with the recognition that such in-service delays would result in the need to rely solely on PJM market capacity and energy in the period post-unit retirements (June 2015 or April 2016, depending on the option and unit) was a direct result of Kentucky Power's voluntarily withdrawing its proposal in Case No. 2011-00401.

RESPONSE

a. The capital cost increase (total cost without AFUDC) associated with the shift in the DFGD in-service date from June 2016 to June 2017 and the completion of the Phase 1 activities is +$111 million.

b. The cost increase for the DFGD project was two-fold. The delay in the project in-service date and an updated cost estimate resulting from the near completion of the Phase 1 conceptual engineering and design activities.

c. The capital cost increase (total cost without AFUDC) associated with the shift in the replacement CC options from June 2016 to June 2017 were comparable to Option 2 (part a of response) at +$93 million for Option 2 and +$100 million for Option 3.

d. The cost increase for the CC replacement options was a result in the delay of the project in-service date.

e. The incremental PJM market capacity and energy impact cannot be determined between the results established in 2011-00401 and 2012-00578 without rerunning the model under both data sets and producing additional diagnostic reports.

f. The Company can neither agree nor disagree without further modeling.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 15, lines 12-16 of the Weaver Testimony.

a. Explain why Kentucky Power chose 2011 as the start of the 30-year economic study period.

b. State whether there was any consideration given to a later start of the study period.

c. Explain how a later start of the study period would affect Kentucky Power's analyses.

RESPONSE

a. The Company chose 2011 as the start date of the economic analysis so those results could be compared back to the results presented in Case No. 2011-00401.

b. No.

c. A later start date would result in greater savings for the recommended option because those savings would be discounted back fewer years.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 18, line 19, of the Weaver Testimony. Explain precisely what is meant by the term "optimum FGD technology."

RESPONSE

In this case, the term "optimum FGD technology" means the best FGD technology option for Big Sandy Unit 2 considering operating parameters, installed costs and operating costs; specifically, the same "NID" dry flue-gas desulfurization (DFGD) technology that had been set forth by Kentucky Power in Case No. 2011-00401.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 19, lines 5-7, of the Weaver Testimony, where it states, "[I]t was further assumed to be located at the existing Big Sandy site, thereby utilizing existing site infrastructure and transmission interconnections".

a. State whether any costs associated with dismantling any of the current facilities at the Sandy Generating Plant to make room for the CC facility were reflected in the analysis.

b. If the answer to a. is no, explain why. If the answer to a. is yes, provide the amounts and descriptions.

RESPONSE

a. No costs associated with dismantling any of the current facilities at the Big Sandy Generating Plant were included in the analysis.

b. There is sufficient room at the Big Sandy Plant to construct a CC without dismantling any of the current facilities at the plant.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 28, line 15, of the Weaver Testimony.

a. Explain why Option 6 was chosen as the base for the analysis.

b. Explain why Option 5A, the least-cost option, was not chosen as the base for the analysis.

RESPONSE

a. The "Base" for the analysis is simply chosen to provide a reference point to compare the economics of the other options against. Any of the options could have been chosen as the Base for the analysis. Option 6 was chosen as the Base for comparison purposes because it contained the same replacement resources (50% Mitchell 1&2 ownership) as the least-cost Option 5A, with the exception of the Big Sandy 1 gas conversion which may be replaced with resource acquired through the Company's RFP process.

b. See response to a. above.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 31, lines 17-20, of the Weaver Testimony. Provide in electronic format, with formulas intact and cells unprotected, all work papers and assumptions that support the estimates of a $2.00 per Mwh for every $100 million in Cumulative Present Worth difference between options.

RESPONSE

See KPSC 1-52 Attachment 1 on the enclosed CD.

WITNESS: Scott C Weaver

CPW Difference: Option #2B vs. Option #6 (per Exhibit SCW-4)		$	560,129,130
	/		100,000,000
"multiples" of $100 million	= (A)		5.60
		$	100,000,000
'Present Value' of KPCo Internal Sales Requirement over period: 2016-2040 (MWh)	/		50,038,000
"per Mwh" KPCo customer cost impact <u>for every $100 MM relative CPW difference</u>	= (B)	$	2.00
<u>per Mwh</u> average (relative) cost impact over period: 2016-2040 (Option #2B vs. Option #6)	(C) = (A) x (B)	$	11.19
# kWh per Mwh	x		1,000
kWh (Assumed) 'Typical' average KPCo Residential customer usage	/		1,000
<u>per month</u> (Assumed) average relative cost impact for a typical KPCo Residential customer using 1,000 kWh per month; 2016-2040 (Option #2B vs. Option #6)	= (D)	$	11.19

Kentucky Power Company

REQUEST

Refer to page 37, lines 19-20, of the Weaver Testimony, which state, "[W]hile that is possible, such existing assets markets are extremely limited, particularly for higher-utilization CC assets." State whether it is known if any high-utilization CC assets were acquired in 2011 and 2012 by utilities in PJM, or are currently in the process of being acquired by utilities in PJM.

RESPONSE

The term "high utilization factor" refers to assets with capacity factors greater than 60%. KPSC 1-53 Attachment 1 shows transactions the Company is aware of that occurred in 2011/2012 for high utilization factor assets.

WITNESS: Scott C Weaver

2011 - 2012 PJM CC Gas Plant Transactions

Plant Name	Year	Acquirer	Seller	Type	Capacity (MW)	In Service Year	ST	ISO	Capacity Factor[1] 2011	Capacity Factor[1] 2012
AES Ironwood	2012	PPL Corp	AES Corp	CC	705	12/31/2001	PA	PJM	77%	64%
Red Oak	2012	Energy Capital Parnters	AES Corp	CC	832	4/1/2002	NJ	PJM	66%	77%
Doswell Energy Center	2011	LS Power	NextEra	CC	332	12/1/1991	VA	PJM	47%	63%
Liberty Electric	2011	Energy Capital Partners	Strategic Value Partners	CC	541	2/1/2002	PA	PJM	54%	62%
Newark Bay Cogeneration Project	2011	Riverstone/Carlyle	Morris Energy Group	CC	120	6/1/1993	NJ	PJM	50%	83%

Note:

1. Source: Ventyx. 2012 Capacity factors are through September.

Kentucky Power Company

REQUEST

Refer to Weaver Testimony, Exhibit SCW-3. Provide the commodity price projections used in the analyses after the year 2030.

RESPONSE

Please see KPSC 1-54 Attachment 1 for the commodity price projection used in the analyses after the year 2030.

WITNESS: Mark A Becker

Summary of Long-Term Commodity Price Forecast Scenarios Used in Strategist® Modeling

(Source: AEP Fundamental Analysis)

Unless otherwise note, all Annual-Average pricing is represented in 'Nominal' Dollars

NATURAL GAS (Henry Hub) ($/MMBtu)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	8.69	10.77	7.64	8.69	8.20
2032	8.87	11.10	7.80	8.87	8.37
2033	9.04	11.46	7.95	9.04	8.54
2034	9.21	11.82	8.11	9.21	8.70
2035	9.38	12.21	8.26	9.38	8.86
2036	9.57	12.59	8.42	9.57	9.03
2037	9.75	12.98	8.58	9.75	9.20
2038	9.94	13.40	8.75	9.94	9.38
2039	10.13	13.82	8.92	10.13	9.56
2040	10.33	14.26	9.09	10.33	9.74

CO2 ($/Metric Tonne)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	16.94	17.34	17.38	18.07	0.00
2032	17.16	17.55	17.61	18.30	0.00
2033	17.38	17.77	17.84	18.54	0.00
2034	17.61	17.99	18.07	18.78	0.00
2035	17.84	18.20	18.30	19.02	0.00
2036	18.07	18.43	18.54	19.27	0.00
2037	18.31	18.66	18.78	19.52	0.00
2038	18.55	18.89	19.03	19.77	0.00
2039	18.79	19.12	19.28	20.02	0.00
2040	19.03	19.35	19.53	20.28	0.00

NAPP (6.0#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	84.95	98.54	75.60	84.54	87.07
2032	86.65	100.52	77.12	86.23	88.82
2033	88.39	102.54	78.67	87.96	90.60
2034	90.16	104.59	80.25	89.73	92.42
2035	91.97	106.69	81.86	91.53	94.27
2036	93.82	108.83	83.50	93.36	96.16
2037	95.70	111.01	85.17	95.24	98.09
2038	97.62	113.24	86.38	97.15	100.06
2039	99.58	115.51	88.62	99.09	102.07
2040	101.58	117.83	90.40	101.08	104.11

CAPP (1.6#) ($/Ton-FOB Mine)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	109.34	131.21	96.22	108.81	112.08
2032	111.48	133.78	98.11	110.94	114.27
2033	113.66	136.40	100.02	113.11	116.50
2034	115.89	139.06	101.98	115.32	118.78
2035	118.15	141.78	103.97	117.58	121.10
2036	120.46	144.56	106.01	119.88	123.47
2037	122.82	147.38	108.08	122.22	125.89
2038	125.22	150.27	110.19	124.61	128.35
2039	127.67	153.20	112.35	127.05	130.86
2040	130.17	156.20	114.55	129.54	133.42

NATURAL GAS (Henry Hub) (REAL, 2010 $) ($/MMBtu)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	6.01	7.46	5.29	6.01	5.68
2032	6.05	7.57	5.32	6.05	5.71
2033	6.08	7.70	5.35	6.08	5.74
2034	6.11	7.84	5.37	6.11	5.76
2035	6.13	7.97	5.39	6.13	5.79
2036	6.16	8.10	5.42	6.16	5.81
2037	6.19	8.24	5.44	6.19	5.84
2038	6.22	8.38	5.47	6.22	5.86
2039	6.24	8.52	5.49	6.24	5.89
2040	6.27	8.66	5.52	6.27	5.91

ON-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	90.85	106.15	84.15	90.28	80.18
2032	92.45	108.84	85.50	91.88	81.49
2033	94.11	111.72	86.81	93.49	82.79
2034	95.77	114.65	88.12	95.02	84.11
2035	97.48	117.76	89.50	96.63	85.46
2036	99.20	120.79	90.91	98.29	86.82
2037	100.96	123.95	92.33	99.98	88.21
2038	102.75	127.22	93.76	101.68	89.62
2039	104.57	130.57	95.21	103.40	91.05
2040	106.43	134.01	96.70	105.16	92.51

OFF-Peak Energy (PJM-AEP Gen Hub) ($/Mwh)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	69.01	81.05	62.21	68.19	57.92
2032	70.73	83.44	63.39	69.66	59.28
2033	72.46	85.92	64.49	71.11	60.58
2034	74.27	88.51	65.63	72.50	61.89
2035	76.13	91.20	66.78	73.92	63.20
2036	77.98	93.89	67.97	75.43	64.59
2037	79.91	96.69	69.19	76.96	66.02
2038	81.89	99.58	70.41	78.51	67.45
2039	83.91	102.56	71.66	80.08	68.92
2040	85.99	105.63	72.93	81.69	70.42

Capacity Value (PJM-RTO RPM) * ($/MW-Day)

	'BASE' Fleet Transition: CSAPR Carbon in 2022	*Alternative Scenarios* FT-CSAPR: HIGHER Band Carbon in 2022	FT-CSAPR: LOWER Band Carbon in 2022	FT-CSAPR: Early Carbon Carbon in 2017	FT-CSAPR: No Carbon
2031	398.84	442.76	368.94	377.75	426.14
2032	404.11	449.34	375.03	381.71	432.76
2033	408.37	456.00	380.13	385.47	438.43
2034	412.13	462.75	384.68	388.61	443.68
2035	416.08	469.58	389.20	391.83	449.24
2036	421.04	476.54	395.03	395.89	455.73
2037	425.63	483.60	400.47	399.62	461.89
2038	430.07	490.76	405.76	403.31	467.95
2039	434.54	498.02	411.10	406.97	474.09
2040	439.17	505.39	416.59	410.75	480.42

* Represents forecasted PJM-RTO Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years

Kentucky Power Company

REQUEST

Refer to Weaver Testimony, Exhibits SCW-5 A through E. Provide in electronic format, with all calculations and formulae intact, the worksheets used to prepare the tables and graphs presented in Exhibits SCW-5 A-E.

RESPONSE

See files labeled KPSC 1-55 WP_Ex SCW-5A through E on the enclosed CD.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Provide Kentucky Power's financial assumptions used in its analyses, as well as supporting data and calculations, for the following:

a. Weighted Average Cost of Capital;

b. Nominal discount rate;

c. Inflation rate; and

d. Real discount rate.

RESPONSE

a. The Weighted Average Cost of Capital is 8.62%,

b. The Nominal discount rate is 8.62%,

c. The inflation rate is 2%, and

d. The Real discount rate was not used in the analysis, only the nominal discount rate.

The supporting data and calculations are provided in KPSC 1-56.xls on the enclosed CD.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 6, lines 1-7, of the Direct Testimony of Ranie K. Wohnhas ("Wohnhas Testimony"), which state:

As a member of the Pool Agreement Kentucky Power has been paying a share of the costs associated with the Mitchell plant since the plant was placed in service and the Company became a party to the Pool Agreement. Because payments through the Pool Agreement are cost based, it is appropriate to transfer the Mitchell plant at that same net book value to KPCo because the transaction is equivalent to a transfer from Ohio Power to Kentucky Power.

a. Provide the date Kentucky Power first became a party to the Pool Agreement.

b. Provide the in-service date(s) for Mitchell Plant Unit 1 and Unit 2.

c. Identify the deficit Pool members which currently make payments to the surplus Pool members.

d. Provide the basis for the decision that Kentucky Power should obtain a 50 percent undivided interest in Mitchell Plant Units 1 and 2, when in Case No. 2011-00401,[6] the decision was to obtain a 20 percent undivided interest.

RESPONSE

a. Kentucky Power became a party to the Pool Agreement on September 20, 1962.

b. The in-service date for Mitchell Plant Unit 1 and Unit 2 was May 31, 1971.

c. As of January 2013, Kentucky Power Company, Appalachian Power Company, and Indiana Michigan Power Company are capacity deficit members of the Pool and make capacity payments to Ohio Power Company, the current surplus member.

d. In KPSC Case No. 2011-00401 the Company determined Big Sandy 2 would continue operation and was looking to replace capacity from Big Sandy 1 which was expected to be retired (plus an incremental amount of capacity to meet its PJM load obligation). In the current case, the determination is that Big Sandy 2 will be retired, so additional capacity is needed for the Company to meet its PJM load obligation. See also the Company's response to KPSC 1-22.

WITNESS: Ranie K Wohnhas

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[6] ID

Kentucky Power Company

REQUEST

Refer to page 6, lines 13-15, of the Wohnhas Testimony, which state, "Exhibit RKW-3 then adds estimated activity for 2012 and 2013 to arrive at an estimated Mitchell Plant balance as of 12/31/2013."

a. State whether the amount of $3,553,000, along with the number of allowances recorded in Accounts 158.1 and158.2, is the 12/31/2013 balance before or after the impact of eliminating the Interim Allowance Agreement ("IAA").

b. Provide the anticipated accounting entries, along with the account titles and the number of allowances, eliminating the IAA.

c. Provide the projected amounts to be recorded in Accounts 158.1 and 158.2 from Exhibit RKW-3, column heading 12/31/2013.

d. State whether the elimination of the IAA accounting entries will be recorded before or after the Transfer and Assumption Transaction accounting entries.

RESPONSE

a. The value and amount of allowances at December 31, 2013 would reflect the impact of the IAA recorded in December 2013.

b. There would be no journal entries recorded to eliminate the IAA. The IAA is expected to cease after December 31, 2013.

c. The entire amount is forecasted in account 158.1.

d. See b. above.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 7, lines 1-6, of the Wohnhas Testimony, which state:

The transferred Mitchell plant liabilities are anticipated to include an inter-company note. Additionally, there will be a surplus assets over liabilities that will be treated as a paid in capital contribution for accounting purposes. As such, a dividend of approximately $75 million may be necessary to return Kentucky Power's equity as a percentage of capitalization to the level immediately prior to the contribution.

a. Provide the accounting entries (account numbers, account titles, along with anticipated amounts) resulting from the Transfer and Assumption Transaction.

b. Provide the accounting entries to be made for the approximately $75 million dividend and explain how soon after the Transfer and Assumption Transaction it is expected this dividend will be paid.

c. Provide Kentucky Power's forecasted equity as a percentage of capitalization immediately prior to the Transfer and Assumption Transaction.

d. Provide Kentucky Power's forecasted equity as a percentage of capitalization immediately after the Transfer and Assumption Transaction, but prior to the dividend of approximately $75 million.

e. Provide Kentucky Power's forecasted equity as a percentage of capitalization immediately after the dividend of approximately $75 million.

f. Provide Kentucky Power's net income amounts from 2008 to 2012 and projected net income for 2013.

g. Explain what Kentucky Power's projected return on equity will be at the time the $75 million dividend is made.

h. Provide Kentucky Power's return on equity for the 12 months ended December 31, 2012.

RESPONSE

a. See KPSC 1- 59 Attachment 1 for the proposed accounting entries based on account balances as of December 31, 2011. While these balances reasonably represent the expected assets, liabilities and total capitalization to be transferred, the actual account balances at the time of the asset transfer will be different.

b. No entries have been made to date. However, Dividends reduce Equity and Cash.

c. Kentucky Power's equity percentage of total capitalization to be approximately 46% prior to the Transfer and Assumption Transaction.

d. Kentucky Power's equity percentage of total capitalization after the Transfer and Assumption Transaction but prior to the $75 million dividend would approximately be 51%.

e. Kentucky Power's equity percentage of total capitalization after the Transfer and Assumption Transaction and after the $75 million dividend would approximately be 46%, which represents the equity percentage of total capitalization before the Transfer and Assumption Transaction.

f. The Net Income for Kentucky Power for 2008-2013E:

(in thousands)
2008: $24,531
2009: $23,936
2010: $35,282
2011: $42,374
2012: $50,978
2013E: $41,088

g. The Transfer and Assumption Transaction will be managed so that Kentucky Power's post transfer capital structure will be held relatively unchanged. We have not forecasted what the expected return on equity will be post transfer.

h. KPCO's per books ROE for the 12 months ending December 31, 2012 using a 13 month average equity balance is 10.85%.

WITNESS: RANIE K WOHNHAS

Kentucky Power Company

REQUEST

Refer to page 8, lines 2-3, of the Wohnhas Testimony, where it states, "[A]s illustrated in Exhibit RKW-4, the overall cost of service impact would have been approximately 8% for 2011." From Exhibit RKW-4 provide the following:

a. Line 2, OSS Revenues (Note 3): Provide for all three columns, amounts broken down by Off-System Sales Revenue, PJM Capacity Sales, PJM Bill and Off-System Sales margin sharing;

b. Line 3, Pool Energy Sales, confirm that Pool Energy Sales Revenue are a decreased revenue (or a cost) which will go away when the Pool is eliminated;

c. Line 8, Net (Gain)/Expense on SO2 Emission Allowances (Note 4): Explain the transactions along with the associated amounts resulting in the ($676,000) change;

d. Line 10, Pool/Market Capacity, which is currently an expense of $54,523,000 and goes to zero after the Asset Transfer and Pool Elimination: State whether this reduction is primarily due to the elimination of the Pool;

e. Line 11, Pool Energy Purchase, which is currently an expense of $15,209,000 and goes to zero after the Asset Transfer and Pool Elimination: State whether this reduction is due to the elimination of the Pool;

f. Line 12, Market Purchased Power for IL:
   (1) Define and explain "IL";
   (2) Explain why the current amount of $4,938,000 is decreased to $3,284;

g. Line 13, PJM Bill (LSE-portion): Explain why the current amount of $19,147,000 is increased by $10,877,000 to $30,024,000;

h. Line 20, Return Requirement (Pre Tax)*: Explain the detailed calculations supporting the $57,345,000 amount; and

i. Line 23, KPCo Sales Revenue: Explain how the $565,286,000 is broken down by retail base rates revenues, retail FAC revenue, retail System Sales Tracker revenue, retail Environmental Surcharge revenue, FERC Wholesale revenue, Associated Utilities revenue, Non-Associated Utilities revenues along with any other applicable revenues; and

j. In this exhibit, explain which category contains the amount of the net change in the cost of fuel between Big Sandy Plant and the Mitchell Plant and provide the amount.

RESPONSE

a. These amounts can be obtained from the workpapers provided in KPSC Staff 1-12 Attachment 1.

b. Yes. Line 3, Pool Energy Sales Revenue are a decreased revenue resulting from the Pool elimination.

c. The decrease in expenses on Line 8 result from the elimination of Interim Allowance Agreement. Details regarding this variance can be found in the file named "IAA Impact Calendar 2011" contained in KPSC Staff 1-12 Attachment 2.

d. Yes. The reduction in line 10, Pool/Market Capacity, is due to the elimination of the Pool.

e. Yes. The reduction in Line 11, Pool Energy Purchase, is due to the elimination of the pool.

f. (1) On line 12, "IL" means "Internal Load".
(2) Kentucky Power's Member Load Ratio (MLR) share of pool purchases that serve internal load ($4.9 Million) is replaced with purchases by Kentucky Power "stand alone" in each hour that Kentucky Power's load exceeded the hourly output of its generation resources, including the proposed asset transfer. These purchases cost $3.3 Million.

g. Details regarding this variance can be found in the file named "Cal 2011 PJM Bill Re-Settled Stand Alone.xlsx" included in KPSC Staff 1-12 Attachment 2. There are many components of the PJM bill which would be impacted. This amount increased primarily because the transmission losses and congestion charges would have been directly assigned to the Company based on its actual energy load and generation from its generating units and from any purchased power resources needed to serve its internal load, rather than allocated to the Company using the pool's MLR allocation methodology had the pool not existed in 2011.

h. The support for this calculation can be found in the workpapers submitted in response to Staff data request 1-12 in attachment KPSC Staff 1-12 Attachment 1 on the "ML Retail Transfer" and "KPCO ROC" worksheets. The balances in accounts which would have been expected to have been recorded on the company's books had the transfer taken place on 12-31-11, which add up to $511.8 million, were adjusted by typical ratemaking adjustments to arrive at a rate base of $513.6 million. This amount was then multiplied by an 11.01% pre-tax return on capitalization, which includes the 10.5% return on equity awarded in the Company's most recent base rate case, to the expected rate base of the Mitchell plant to get the required return on rate base that the Company would expect to recover in customer rates.

i. This amount includes all retail revenues recorded in FERC accounts 440, 442, 444, and 445, which totaled $559,169,090, and FERC Wholesale revenues recorded in accounts 4470027, 4470033, and 4470150, which totaled $6,117,376.

Please see KPSC 1-60 Attachment 1 for additional detail.

j. This exhibit does not include the amount of the net change in the cost of fuel or any other operating expenses of the Big Sandy Plant, because it was assumed that there would be no change in the cost of fuel or the amount of hours Big Sandy would have generated in 2011 due to the elimination of the pool. The units are dispatched economically by PJM without regard to the existence of any pooling arrangements that a generator may be a participant in or ownership of the units.
A total of $118.9 million of fuel was recorded on Ohio Power's books in account 501 in 2011 for 50% of the Mitchell plant. This amount is included with its O&M Expense in the $159.7 million on line 18 of the Exhibit.

WITNESS: Ranie K Wohnhas

Total Revenue[1]	Base Rate Revenue	Fuel Revenue in Base Revenue	Fuel Adjustment Revenue	ECR Revenue	System Sales Revenue	DSM Revenue[2]	Capacity Charge Revenue	Residentia l HEAP	Net Merger Savings Credit	Unbiled & Estimated Revenue	FERC Wholesale Revenue
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
$565,286,466	$551,284,601	$204,579,041	$6,793,381	$13,053,108	-$3,111,903	$3,323,742	$6,236,504	$255,855	-$58	-$15,342,398	$6,117,376

[1] Total Revenues include unbilled and estimated revenues for the current and the prior year but do not include associated and non-associated utilites revenues.

[2] DSM Revenues (i) are booked directly to Miscellaneous Revenue, therefore are not included in (a) Total Electric Revenues.

Kentucky Power Company

REQUEST

Refer to page 8, lines 11-12, of the Wohnhas Testimony, where it states, ". . . the Company will need to file an application for a base rate change no later than June 28, 2013, with new rates to be effective January 1, 2014." State whether Kentucky Power anticipates filing an application for a base rate change to be effective July 1, 2015, after Big Sandy Plant Unit 2 is retired.

RESPONSE

No decision has been made.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 8, lines 18-22, of the Wohnhas Testimony, which states:

The retirement of Big Sandy Unit 2 would occur independent of any particular generation resource option that leads to its eventual retirement, including the transfer of a fifty percent interest in the Mitchell plant. The costs associated with the Big Sandy Unit 2 retirement will be addressed in the Company's next base rate case.

a. State whether there is a negative salvage amount or demolition amount for Big Sandy Plant currently reflected in its depreciation rates.

b. If the answer to a. is yes, provide the total amount and the amount that has been recovered from ratepayers over the life of Big Sandy Plant.

c. Provide what the depreciation rate for the generation plant would be for Kentucky Power once the Transfer and Assumption Transaction is completed.

d. State whether, once the Transfer and Assumption Transaction is completed, the annual amount of depreciation expense for generation plant would change from the current annual amount of depreciation expense for Kentucky Power's generation plant.

e. State whether Kentucky Power believes any emission allowances will remain at the retirement of Big Sandy Unit 2 and describe what will be done with those remaining emission allowances.

RESPONSE

a. Yes, there is a negative salvage amount or demolition amount for Big Sandy Plant currently reflected in its depreciation rates.

b. The actual amount of net salvage recovered from ratepayers over the life of Big Sandy Plant has not been tracked in the Company's accounting records. However, as of December 31, 2012, the estimated balance of the portion of accumulated depreciation related to net salvage (includes removal costs and credits for salvage) for Big Sandy Plant is $56.3 million.

Kentucky Power Company

c. Until the Company's next base rate case, the depreciation rates for Big Sandy and Mitchell plants would be the rates currently used by Kentucky Power and Ohio Power which are as follows:

Big Sandy Plant 3.78% for each individual plant account

Mitchell Plant by plant account:
311 2.87%
312 3.90%
314 2.86%
315 2.39%
316 2.79%

d. The annual depreciation expense for Kentucky's generation plant would change when the Transfer and Assumption Transaction is completed since depreciation expense would be recorded on both Big Sandy Plant (until its retirement) and on Kentucky's share of Mitchell Plant.

e. Kentucky Power believes Big Sandy Unit 2 will have emission allowances of current and future vintages on the date of retirement. Under the Clean Air Act Amendments of 1990, Big Sandy Unit 2 has been allocated Title IV SO2 allowances for each future vintage year 30 years into the future. The EPA will continue to allocate future allowances for the future 30th year, each year, regardless of the retirement status of the unit. The allowances may be used at another Kentucky Power facility or sold.

Under the Clean Air Interstate Rule (CAIR), Big Sandy Unit 2 has been allocated Annual and Seasonal NOx allowances through 2014. Beginning in 2015, the allocation is expected to be reduced. Depending on the number of allowances allocated and the emissions from all of Kentucky Power's units, there may be allowances remaining on the date of retirement. At some point, the EPA will discontinue allocating new CAIR NOx allowances for Big Sandy Unit 2. Any remaining allowances may be used at another Kentucky Power facility or sold.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

State when Ohio Power first began incurring costs associated with the installation of the FGDs on Mitchell Plant Units 1 and 2.

RESPONSE

Ohio Power first began incurring costs associated with the installation of the FGDs on Mitchell Plant Units 1 and 2 in 2003.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 11, lines 2-3 of the Wohnhas Testimony, which states, "[A] detailed break-down of these expenditures is shown on Exhibit-RKW 5." Provide the following:

a. A detailed reconciliation and explanation of the amounts shown on RKW-Exhibit 5, Landfill column and Kentucky Power's response in Case No. 2011-00401.[7] Commission Staff's First Request for Information, Item No. 18, FGD Landfill column;

b. A detailed reconciliation and explanation of the amounts shown on RKW-Exhibit 5, WFGD column and Kentucky Power's response in Case No. 2011-00401.[8]

c. A detailed explanation as to the type of services and or costs reflected in the different categories in the DFGD column on RKW-Exhibit 5;

d. An explanation as to whether any of the costs shown on RKW-Exhibit 5 were directly incurred as a result of the Transfer and Assumption Transaction which is at issue in this proceeding; and

e. The reasoning for establishing the land purchase cost of $678,412 as a Regulatory Asset, given that land is a tangible asset and can be sold.

RESPONSE

a & b. Please see KPSC 1-16.

c. Internal Labor - Direct labor of employees directly assigned to Kentucky Power.
Outside Services - Contract engineering services needed to complete Phase I.
Service Corporation Charges - Allocated labor of service corporation employees working on this project.
Overheads - Various labor related overheads.
Other - Miscellaneous.

d. None of the costs shown on RKW-Exhibit 5 are a result of the Transfer and Assumption Transaction.

e. The land purchase cost is $630,376 as shown on RKW-Exhibit 5 and this amount relates to acquired land for the landfill portion of the FGD project but will be reclassified out of account 183 by KPCo. Please also see KPSC 1-16.

WITNESS: Ranie K Wohnhas

[7] Id
[8] Id

Kentucky Power Company

REQUEST

Provide a copy of the most current actual East Interchange Power Statement and Related Data Actual.

RESPONSE

Please see KPSC 1-65 Attachment 1.

WITNESS: Ranie K Wohnhas

AEP AMERICAN® ELECTRIC POWER

Date **December 2012**

Subject **East Interchange Power Statement and Related Data**
December 2012 Actual

Reviewer: Richard Quaintance
2/1/2013

Approved Steve Molnar
2/1/2013

To See Distribution List

Enclosed is the East Interchange Power Statement and Related Data, issued pursuant to the AEP Interconnection Agreement, indicating actual data for the month of December 2012.

NOTE: Effective November 2010 Actual Cycle the SIA Sharing calculations will be performed outside of the Interchange Power Statement by Accounting. Please contact Craig Adelman at 614-583-7756 or Audinet 8-220-7756 if further information is needed.

ACTUAL
INTERCHANGE POWER STATEMENT
FOR THE MONTH OF
December 2012

STATEMENT OF SETTLEMENT TO BE MADE
FOR ELECTRIC POWER AND ENERGY RECEIVED AND DELIVERED
APPLICABLE TO SEPTEMBER 2006 BUSINESS

Pursuant to the Interconnection Agreement, dated July 6, 1951,

as Amended

by and among

Appalachian Power Company (APCo),

Columbus Southern Power Company (CSP),

Indiana Michigan Power Company, (I&M),

Kentucky Power Company (KPCo),

Ohio Power Company (OPCo),

and with

American Electric Power Service Corporation

as Agent.

Prepared by:
Commercial Operations
Pool Settlements Group

CONTENTS

ACTUAL: December 2012 PAGE (1)

			MWh		($)	
	(SOURCE: PAGE 2)		MEMBER RECEIVED FROM POOL	MEMBER DELIVERED TO POOL	AMOUNT DUE TO AGENT (CHARGE)	AMOUNT DUE FROM AGENT (CREDIT)
I.	ACTUAL	APCO	2,295,421	427,588	76,981,001	15,801,340
	BILLING	KPCO	503,080	116,857	16,061,246	2,930,821
	AMOUNT	I&M	440,887	1,263,048	15,507,538	29,759,648
		OPCO	574,287	2,006,182	18,387,126	78,445,103
		CSP	0	0	0	0
		TOTAL	3,813,676	3,813,676	126,936,911	126,936,911
II.	PREVIOUSLY	APCO	2,302,147	432,699	74,017,477	15,784,040
	ESTIMATED	KPCO	501,754	114,401	15,359,212	2,637,665
	BILLING	I&M	442,168	1,261,550	15,309,543	26,745,872
	AMOUNT	OPCO	571,373	2,008,793	17,591,800	77,110,455
		CSP	0	0	0	0
		TOTAL	3,817,442	3,817,442	122,278,032	122,278,031
III.	ADJUSTMENT	APCO	(6,726)	(5,110)	2,963,524	17,300
	TO BE BOOKED	KPCO	1,326	2,456	702,034	293,156
	NEXT MONTH	I&M	(1,281)	1,498	197,995	3,013,776
	(I - II)	OPCO	2,914	(2,611)	795,326	1,334,648
		CSP	0	0	0	0
		TOTAL	(3,766)	(3,766)	4,658,880	4,658,880
IV.	ADJUSTMENT FOR TRANSMISSION			APCO	0	2,376
	SERVICE (PURCHASES) TO BE			KPCO	0	475
	BOOKED NEXT MONTH			I&M	0	1,634
	(SEE APPENDIX VI)			OPCO	4,485	0
				CSP	0	0
				TOTAL	4,485	4,485
V.	ADJUSTMENT TO ALLOCATION OF			APCO	0	0
	TRADING & MARKETING REALIZATION			KPCO	0	0
	TO BE BOOKED NEXT MONTH			I&M	0	0
	(SEE PAGE 6B)			OPCO	0	0
				CSP	0	0
				West. AEP	0	0
				TOTAL	0	0
VI.	ADJUSTMENT FOR PJM CHARGES			APCO	0	153,782
	TRANSFERRED FROM			KPCO	0	60,092
	nMARKET TO AEE (NON-ECR)			I&M	0	187,919
	TO BE BOOKED NEXT MONTH			OPCO	0	401,009
	(SEE APPENDIX IX)			CSP	0	0
				East. AEP (Co. 122)	802,802	0
				TOTAL	802,802	802,802
VII.	ADJUSTMENT FOR PJM CHARGES			APCO	39,308	0
	(NON-ECR) FROM INVOICE			KPCO	7,907	0
	TO BE BOOKED NEXT MONTH			I&M	27,091	0
	(SEE APPENDIX IX)			OPCO	55,354	0
				CSP	0	0
				East. AEP (Co. 122)	0	129,660
				TOTAL	129,660	129,660

ACTUAL: December 2012

			($)	
			AMOUNT DUE TO AGENT (CHARGE)	AMOUNT DUE FROM AGENT (CREDIT)
VIII.	ADJUSTMENT FOR OFFSET OF	APCO	0	79,563
	BUCKEYE PASS-THROUGH CHARGES	KPCO	0	15,967
	ASSOCIATED WITH PJM	I&M	0	54,733
	TO BE BOOKED NEXT MONTH	OPCO	0	111,919
	(SEE APPENDIX IX)	CSP	0	0
		East. AEP (Co. 122)	262,182	0
		TOTAL	262,182	262,182
IX.	ADJUSTMENT FOR BUCKEYE SHARE	APCO	0	0
	OF PJM CONGESTION CHARGES	KPCO	0	0
	TO BE BOOKED NEXT MONTH	I&M	0	0
	(SEE APPENDIX IX)	OPCO	0	0
		CSP	0	0
		East. AEP (Co. 122)	0	0
		TOTAL	0	0
X.	*ACTUAL THIS MONTH*	APCO	0	30,496,690
	(SEE APPENDIX VI)	KPCO	0	6,107,972
	(Net amounts due System Agent to	I&M	0	20,946,643
	effect sharing by MLR in revenues	OPCO	0	42,859,240
	and cost of purchases for AEP System	CSP	0	0
	cash-settled transactions)	East. AEP (Co.122)	100,410,544	0
		TOTAL	100,410,544	100,410,544
XIII.	ESTIMATED THIS MONTH	APCO	0	30,642,260
	(SEE APPENDIX VI)	KPCO	0	6,137,128
		I&M	0	21,046,627
		OPCO	0	43,063,818
		CSP	0	0
		East. AEP (Co.122)	100,889,832	0
		TOTAL	100,889,832	100,889,832
XI.	ADJUSTMENT FOR RECLASS OF ENTERGY	APCO	0	0
	SPREADS FOR DIRECT ALLOCATION TO WEST	KPCO	0	0
	(SEE APPENDIX VIII, pages 2, 3, & 4)	I&M	0	0
		OPCO	0	0
		CSP	0	0
		East. AEP (Co. 28)	0	0
		TOTAL	0	0
XIV.	ADJUSTMENT TO BE MADE NEXT MONTH	APCO	145,569	0
		KPCO	29,156	0
		I&M	99,984	0
		OPCO	204,578	0
		CSP	0	0
		East. AEP (Co.122)	0	479,287
		TOTAL	479,287	479,287

NOTE: This statement provides amounts to be booked in accounts 555 and 447 and the settlement through the System Pool Account Agent.

ACTUAL: December 2012

SYSTEM ACCOUNT

RECAPITULATION OF CAPACITY, ENERGY, AND OTHER CHARGES

			CAPACITY (PAGE 3)		$ CAPACITY (PAGE 3)		$ ENERGY (PAGE 4)	
			SURPLUS/ (DEFICIT) kW	RATE $/kW	CHARGE A/C 555 (1)	CREDIT A/C 447 (2)	CHARGE A/C 555 (3)	CREDIT A/C 447 (4)
I.	ACTUAL BILLING AMOUNT	APCO	(1,165,600)	12.26	14,290,256	0	62,690,745	15,801,340
		KPCO	(154,600)	12.26	1,895,396	0	14,165,850	2,930,821
		I&M	(148,900)	12.26	1,825,514	0	13,682,024	29,759,648
		OPCO	1,469,100	12.26	0	18,011,166	18,387,126	60,433,937
		CSP	0	0.00	0	0	0	0
		TOTAL			18,011,166	18,011,166	108,925,745	108,925,745
II.	PREVIOUSLY ESTIMATED BILLING AMOUNT	APCO			14,687,818	0	59,329,659	15,784,040
		KPCO			1,948,127	0	13,411,085	2,637,665
		I&M			1,876,301	0	13,433,242	26,745,872
		OPCO			0	18,512,246	17,591,800	58,598,209
		CSP			0	0	0	0
		TOTAL			18,512,246	18,512,246	103,765,786	103,765,785
IV.	ADJUSTMENT TO BE BOOKED NEXT MONTH (I - II + III)	APCO			(397,562)	0	3,361,086	17,300
		KPCO			(52,731)	0	754,765	293,156
		I&M			(50,787)	0	248,782	3,013,776
		OPCO			0	(501,080)	795,326	1,835,728
		CSP			0	0	-	-
		TOTAL			(501,080)	(501,080)	5,159,960	5,159,960

			ENERGY MWh		$ TOTAL OF ALL ABOVE	
			(PAGE 4) FROM POOL	(PAGE 4) TO POOL	(1)+(3) CHARGE (7)	(2)+(4) CREDIT (8)
I.	ACTUAL BILLING AMOUNT	APCO	2,295,421	427,588	76,981,001	15,801,340
		KPCO	503,080	116,857	16,061,246	2,930,821
		I&M	440,887	1,263,048	15,507,538	29,759,648
		OPCO	574,287	2,006,182	18,387,126	78,445,103
		CSP	0	0	0	0
		TOTAL	3,813,676	3,813,676	126,936,911	126,936,911
II.	PREVIOUSLY ESTIMATED & ENERGY BILLING AMOUNT	APCO	2,302,147	432,699	74,017,477	15,784,040
		KPCO	501,754	114,401	15,359,212	2,637,665
		I&M	442,168	1,261,550	15,309,543	26,745,872
		OPCO	571,373	2,008,793	17,591,800	77,110,455
		CSP	0	0	0	0
		TOTAL	3,817,442	3,817,442	122,278,032	122,278,031
IV.	ADJUSTMENT TO BE BOOKED NEXT MONTH (I - III)	APCO	(6,726)	(5,110)	2,963,524	17,300
		KPCO	1,326	2,456	702,034	293,156
		I&M	(1,281)	1,498	197,995	3,013,776
		OPCO	2,914	(2,611)	795,326	1,334,648
		CSP	0	0	0	0
		TOTAL	(3,766)	(3,766)	4,658,880	4,658,880

ACTUAL: December 2012

CALCULATION OF MEMBER PRIMARY CAPACITY SURPLUS/(DEFICIT) kW AND $ SETTLEMENT

MEMBER	MEMBER PRIMARY CAPACITY kW (APPENDIX II)	MEMBER LOAD RATIO (APPENDIX I)	PRIMARY CAPACITY kW RESERVATION (SYS. kW) * (2)	SURPLUS (DEFICIT) CAPACITY kW
	(1)	(2)	(3)	(4) = (1) - (3)
APCO	6,951,000	0.30372	8,116,600	(1,165,600)
KPCO	1,471,000	0.06083	1,625,600	(154,600)
I&M	5,426,000	0.20861	5,574,900	(148,900)
OPCO	12,876,000	0.42684	11,406,900	1,469,100
CSP	0	0.00000	0	0
TOTAL	26,724,000	1.00000	26,724,000	

MEMBER CAPACITY $ SETTLEMENT

MEMBER	SURPLUS (DEFICIT) CAPACITY kW	CAPACITY RATE $/kW *			CREDIT (CHARGE) ** $
	(1)		(2)		(3)
APCO	(1,165,600)	*****	+	*****	(14,290,256)
KPCO	(154,600)	*****	+	*****	(1,895,396)
I&M	(148,900)	*****	+	*****	(1,825,514)
OPCO	1,469,100	10.64	+	1.62	18,011,166
CSP	0	*****	+	*****	0

EQUALIZATION CAPACITY RATE: 12.2600

(This is the average $/kW rate paid by deficit members.)

NOTES:

* The sum of the Member's Primary Capacity Investment Rate (Appendix III) and the Member's Capacity Fixed Operating Rate (Appendix IV & V) applicable to Members having a Member Primary Capacity Surplus.

** Credits should be recoreded in Account 447, Sales for Resale.
Charges should be recorded in Account 555, Purchased Power.

December 2012

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT

		MWH		$	
		RECEIVED FROM POOL	DELIVERED TO POOL	CHARGE MEMBER A/C 555	CREDIT MEMBER A/C 447
I. AEP EXTERNAL ENERGY *		(MLR SHARE)	(AS SUPPLIED)	(MLR SHARE)	(AS SUPPLIED)
ENERGY COST	APCO	969,194	758,023	29,700,791	27,256,990
RECOVERY AND MLR	KPCO	194,113	153,268	5,948,568	4,035,100
ALLOCATION FOR ALL	I&M	665,691	705,876	20,399,980	20,401,271
AEP SYSTEM	OPCO	1,362,080	1,573,911	41,740,701	46,096,679
DELIVERIES TO	CSP	0	0	0	0
NON-AFFILIATED COS.	AEP	3,191,078	3,191,078	97,790,040	97,790,040
ADJUSTMENT TO	APCO	(330,567)	(330,567)	(11,459,231)	(11,459,231)
PREVENT RECOGNITION	KPCO	(36,430)	(36,430)	(1,104,731)	(1,104,731)
OF SALES BY POOL	I&M	(225,586)	(225,586)	(6,739,021)	(6,739,021)
MEMBERS TO	OPCO	(787,887)	(787,887)	(23,355,600)	(23,355,600)
THEMSELVES	CSP	0	0	0	0
(PAGE 7)	AEP	(1,380,469)	(1,380,469)	(42,658,584)	(42,658,584)
SUBTOTAL	APCO	638,627	427,457	18,241,560	15,797,759
AEP EXTERNAL	KPCO	157,683	116,838	4,843,837	2,930,369
ENERGY	I&M	440,105	480,290	13,660,959	13,662,249
	OPCO	574,193	786,025	18,385,101	22,741,079
	CSP	0	0	0	0
	AEP	1,810,609	1,810,609	55,131,456	55,131,456
II. INTERNAL ENERGY AMONG POOL MEMBERS					
PRIMARY	APCO	1,656,793	0	44,449,186	0
ENERGY	KPCO	345,397	0	9,322,013	0
(PAGE 8)	I&M	0	782,683	0	16,095,780
	OPCO	0	1,219,508	0	37,675,420
	CSP	0	0	0	0
	AEP	2,002,190	2,002,190	53,771,199	53,771,199
ECONOMY	APCO	0	0	0	0
ENERGY	KPCO	0	0	0	0
(PAGE 9)	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	AEP	0	0	0	0
III. TOTAL SYSTEM ACCOUNT ENERGY					
(I + II)	APCO	2,295,421	427,588	62,690,745	15,801,340
	KPCO	503,080	116,857	14,165,850	2,930,821
	I&M	440,887	1,263,048	13,682,024	29,759,648
	OPCO	574,287	2,006,182	18,387,126	60,433,937
	CSP	0	0	0	0
	AEP	3,813,676	3,813,676	108,925,745	108,925,745

NOTE: (*) Source of data is "Summary - System Account Settlement for AEP System Deliveries" in the Power Tracker Flow report. The MWh and $ CREDIT AMOUNTS labeled "As Supplied" correspond to the MWh and COST columns associated with the "Off-System Allocation". The MWh and $ CHARGE AMOUNTS labeled "MLR SHARE" correspond to the MWh and COST columns associated with the "Off-System Obligation". Not included are any demand charge portions of purchased power out-of-pocket costs allocated to AEP System deliveries (such demand costs would have no net effect in the System Account because they are incurred and allocated in identical MLR proportion, thus netting zero). Also, see NOTE (1), page 6

ACTUAL: December 2012

SYSTEM ACCOUNT
RECONCILIATION OF INTERRUPTIBLE CUSTOMERS
BUY-THROUGH ALLOCATION OR INTERNAL CUSTOMERS IN GENERAL
WHEREBY POOL ENERGY IS SPECIFICALLY ALLOCATED

I. AEP POOL ENERGY *		MWH RECEIVED FROM POOL	MWH DELIVERED TO POOL (AS SUPPLIED)	$ CHARGE MEMBER A/C 555	$ CREDIT MEMBER A/C 447 (AS SUPPLIED)
ENERGY AND ENERGY	APCO	0	132	0	3,581
COST RECOVERY	KPCO	0	20	0	452
ALLOCATED TO	I&M	782	75	21,065	1,619
SPECIAL SERVICE	OPCO	94	650	2,025	17,438
CUSTOMERS	CSP	0	0	0	0
	AEP	876	876	23,090	23,090
PREVIOUSLY	APCO	0	599	0	57,020
ESTIMATED	KPCO	0	0	0	0
AMOUNT	I&M	536	31	51,044	2,990
	OPCO	94	0	8,967	0
	CSP	0	0	0	0
	AEP	630	630	60,011	60,010
ADJUSTMENT	APCO	0	(467)	0	(53,439)
TO BE BOOKED	KPCO	0	20	0	452
NEXT MONTH	I&M	246	44	(29,979)	(1,371)
	OPCO	0	650	(6,942)	17,438
	CSP	0	0	0	0
	AEP	246	246	(36,921)	(36,920)

NOTES: (*) Figures on this page are carried on to "Total System Account Energy", Item III, page 4.
(1) Adjustment from August 2005 for buy-through allocation error in ECR

ACTUAL: December 2012

AEP SYSTEM DELIVERIES TO OTHER COMPANIES
RECONCILIATION OF SYSTEM ACCOUNT COST EQUALIZATION
TOTAL AND NET REVENUES

Cost Equalization for AEP System Deliveries
in the System Account (Page 4, Item 1)

	CHARGE MEMBER (MLR * COL. 2 TOT.) ($)	CREDIT MEMBER (1) COST RECOVERY ($)	CREDIT MEMBER (2) SYSTEM SALES REVENUES ($)
	(1)	(2)	(3)
APCO	29,700,791	27,256,990	34,205,395
KPCO	5,948,568	4,035,100	6,850,765
I&M	20,399,980	20,401,271	23,493,967
OPCO	41,740,701	46,096,679	48,071,352
CSP	0	0	0
TOTAL	97,790,040	97,790,040	112,621,478

	DEMAND CHARGE PAID TO THIRD PARTIES ($)	NET REVENUE REALIZED BY THE MEMBERS (I.E., EXCESS OF REVENUE OVER INCURRED COSTS) ($)	(MLR) MEMBER LOAD RATIO THIS MONTH
	(5)	(6)=(4)-(5)	(7)
APCO	0	4,504,604	0.30372
KPCO	0	902,197	0.06083
I&M	0	3,093,987	0.20861
OPCO	0	6,330,651	0.42684
CSP	0	0	0.00000
TOTAL	0	14,831,438	1.00000

NOTES:

(1) The variable energy costs, which are incurred by the members in supplying energy for AEP System deli companies are recovered as credits. Includes adjustment to account for the difference between mark SO2 & NOX emission allowances used in dispatch versus operating companies inventory costs (see page

(2) The total of the credits reported in the Power Tracker report for Sales Tariff Report with Sales Dem

EXCESS OF REVENUE OVER ENERGY COSTS ($)
(4)=(3)-(1)
4,504,604
902,197
3,093,987
6,330,651
0
14,831,438

veries to non-affiliated
:et price of
11).

and & Adjustments

ACTUAL: December 2012

ALLOCATION OF REALIZATION SHARING BY EASTERN AEP OPERATING COMPANIES AND ACCOUNT NUMBERS

	SIA SHARING RATIOS			TOTAL SHARE
EASTERN AEP:	100.000% ×	0 =	$0	$0
WESTERN AEP:	0.000% ×	0 =	$0	$0
				$0

REALIZATION TO BE SHARED:	$0
LESS EASTERN AEP REALIZATION SHARE:	$0
WESTERN REALIZATION SHARE:	$0
LESS AMOUNT ALREADY BOOKED ON WEST	$0
TOTAL DOLLAR TRANSFER FROM WESTERN AEP TO EASTERN AEP:	$0

TRANSFER OF FUNDS BETWEEN EASTERN AEP AND WESTERN AEP (1)

EASTERN AEP JOURNAL ENTRIES

	ACCOUNT NO. 4470.144	ACCOUNT NO. 4210.043	ACCOUNT NO. 4210.044	ACTUAL TOTAL OF ALL ACCOUNTS	PREVIOUS ESTIMATED TOTAL	PRIOR PERIOD ADJUSTMENTS ACCOUNT NO. 4470.144	PRIOR PERIOD ADJUSTMENTS ACCOUNT NO. 4210.043	ADJUSTMENT TO BE BOOKED NEXT MONTH
APCO	0	0	0	0	0	0	0	0
KPCO	0	0	0	0	0	0	0	0
I&M	0	0	0	0	0	0	0	0
OPCO	0	0	0	0	0	0	0	0
CSP	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0

WESTERN AEP JOURNAL ENTRIES

	ACCOUNT NO. 4470.144	ACCOUNT NO. 4210.043	ACCOUNT NO. 4210.044	ACTUAL TOTAL OF ALL ACCOUNTS	PREVIOUS ESTIMATED TOTAL	PRIOR PERIOD ADJUSTMENTS ACCOUNT NO. 4470.144	PRIOR PERIOD ADJUSTMENTS ACCOUNT NO. 4470.043	ADJUSTMENT TO BE BOOKED NEXT MONTH
PSO	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0
TCC	0	0	0	0	0	0	0	0
TNC	0	0	0	0	0	0	0	0
TOTAL	0	0	0	0	0	0	0	0

NOTE: (1) Details of the realization sharing by account numbers is shown in Appendix VIII, page 7.

ACTUAL: December 2012

CALCULATION OF ADJUSTMENT TO PREVENT RECOGNITION OF SALES BY POOL MEMBERS TO THEMSELVES

I. GENERATION SUPPLIED TO THE POOL FOR SYSTEM SALES (1)

	MWh	COST (2) ($)	MLR (APPENDIX I)	ADJUSTMENT MWh	ADJUSTMENT COST ($)
APCO	472,026	13,099,698	0.30372	143,364	3,978,640
KPCO	124,405	3,120,169	0.06083	7,568	189,800
I&M	535,907	12,466,140	0.20861	111,796	2,600,561
OPCO	1,191,152	33,849,691	0.42684	508,431	14,448,402
CSP	0	0	0.00000	0	0
TOTAL	2,323,490	62,535,698	1.00000	771,159	21,217,403

II. OVEC PURCHASES SUPPLIED FOR SYSTEM SALES (1)

	MWh	COST ($)	MLR (APPENDIX I)	ADJUSTMENT MWh	ADJUSTMENT COST ($)
APCO	141,890	9,589,103	0.30372	43,095	2,912,402
KPCO	0	0	0.06083	0	0
I&M	70,988	4,797,472	0.20861	14,809	1,000,801
OPCO	180,234	5,826,977	0.42684	76,931	2,487,187
CSP	0	0	0.00000	0	0
TOTAL	393,113	20,213,551	1.00000	134,835	6,400,390

III. PURCHASED POWER SUPPLIED FOR SYSTEM SALES (3)

	AS ALLOCATED MWh	AS ALLOCATED COST ($)
APCO	144,108	4,568,189
KPCO	28,862	914,931
I&M	98,981	3,137,659
OPCO	202,525	6,420,011
CSP	0	0
TOTAL	474,475	15,040,791

IV. TOTAL ADJUSTMENT (I + II + III)

	TOTAL ADJUSTMENT TO PAGE 4 MWh	TOTAL ADJUSTMENT TO PAGE 4 COST ($)
APCO	330,567	11,459,231
KPCO	36,430	1,104,731
I&M	225,586	6,739,021
OPCO	787,887	23,355,600
CSP	0	0
TOTAL	1,380,469	42,658,584

NOTES:

(1) The source of the MWh and COST data is the "Unit Cost" Report for Generation and Purchase Power Report for purchases.

(2) See Note (1), page 6.

(3) Excludes OVEC purchases allocated to System Sales (shown in II above).

ACTUAL: December 2012

PRIMARY ENERGY

RECEIVING MEMBER	MWh	RECEIVED ENERGY $/MWh	RECEIVED ENERGY CHARGE ($)
APCO	1,656,793	26.828	44,449,186
KPCO	345,397	26.989	9,322,013
I&M	0	0.000	0
OPCO	0	0.000	0
CSP	0	0.000	0
TOTAL ALL MEMBERS RECEIVED	2,002,190	26.856	53,771,199

TOTAL DELIVERED BY MEMBER	MWh	DELIVERED ENERGY $/MWh	DELIVERED ENERGY CREDIT ($)
APCO	0	0.000	0
KPCO	0	0.000	0
I&M	782,683	20.566	16,095,780
OPCO	1,219,508	30.897	37,675,420
CSP	0	0.000	0
TOTAL ALL MEMBERS DELIVERED:	2,002,190	26.856	53,771,199

SOURCE: Power Tracker calculates Primary energy deliveries and associated charges for each hour of the month and aggregates such MWh and Charges for the month as reported above. The used in the hourly calculations are derived in APPENDIX V.

ACCOUNT 151 FUEL COST ASSOCIATED WITH PRIMARY ENERGY — ACTUAL: December 2012

RECEIVING MEMBER	MWh	RECEIVED ENERGY $/MWh	RECEIVED ENERGY CHARGE ($)
APCO	1,656,793	22.410	37,128,818
KPCO	345,397	22.587	7,801,548
I&M	0	0.000	0
OPCO	0	0.000	0
CSP	0	0.000	0
TOTAL ALL MEMBERS RECEIVED	2,002,190	22.441	44,930,367

TOTAL DELIVERED BY MEMBER	MWh	DELIVERED ENERGY $/MWh	DELIVERED ENERGY CREDIT ($)
APCO	0	0.000	0
KPCO	0	0.000	0
I&M	782,683	15.503	12,133,715
OPCO	1,219,508	26.896	32,796,651
CSP	0	0.000	0
TOTAL ALL MEMBERS DELIVERED:	2,002,190	22.441	44,930,367

ACTUAL: December 2012

ECONOMY ENERGY

RECEIVING MEMBER	MWh	RECEIVED ENERGY $/MWh	CHARGE ($)
APCO	0	0.000	0
KPCO	0	0.000	0
I&M	0	0.000	0
OPCO	0	0.000	0
CSP	0	0.000	0
TOTAL ALL MEMBERS RECEIVED	0	0.000	0

TOTAL DELIVERED BY MEMBER	MWh	DELIVERED ENERGY $/MWh	CREDIT ($)
APCO	0	0.000	0
KPCO	0	0.000	0
I&M	0	0.000	0
OPCO	0	0.000	0
CSP	0	0.000	0
TOTAL ALL MEMBERS DELIVERED:	0	0.000	0

SOURCE: Power Tracker calculates for each hour of the month the MWh of ECONOMY delivei and the associated charges and credits based upon an equal sharing of the savings in expense, then aggregates such hourly data for the month to arrive at the totals rep

ACCOUNT 151 FUEL COST ASSOCIATED WITH ECONOMY ENERGY   ACTUAL: December 2012

RECEIVING MEMBER	MWh	RECEIVED ENERGY $/MWh	RECEIVED ENERGY CHARGE ($)
APCO	0	0.000	0
KPCO	0	0.000	0
I&M	0	0.000	0
OPCO	0	0.000	0
CSP	0	0.000	0
TOTAL ALL MEMBERS RECEIVED	0	0.000	0

TOTAL DELIVERED BY MEMBER	MWh	DELIVERED ENERGY $/MWh	DELIVERED ENERGY CREDIT ($)
APCO	0	0.000	0
KPCO	0	0.000	0
I&M	0	0.000	0
OPCO	0	0.000	0
CSP	0	0.000	0
TOTAL ALL MEMBERS DELIVERED:	0	0.000	0

December 2012

AEP SYSTEM
ALLOWANCES CONSUMED FOR SALES
TO NON-AFFILIATED SYSTEMS (a)

		GENERATION ALLOCATED TO SALES TO NON-AFFILIATED SYSTEMS (MWh)	TOTAL GENERATION (MWh)	SYSTEM SALES ALLOCATION FACTOR	SO2 EMISSIONS (In Tons) (b)	SO2 EMISSION EXPENDED FOR SYSTEM SALES
		(1)	(2)	(3)=(1)/(2)	(4)	(5)=(3)*(4)
APCO	AMOS 1	114,758	438,567	0.2617	128	33.4932
	AMOS 2	54,579	166,360	0.3281	49	16.0757
	AMOS 3	60,939	224,150	0.2719	58	15.7682
	CEREDO1	0	0	0.0000	0	0.0000
	CEREDO2	0	0	0.0000	0	0.0000
	CEREDO3	0	0	0.0000	0	0.0000
	CEREDO4	0	0	0.0000	0	0.0000
	CEREDO5	0	0	0.0000	0	0.0000
	CEREDO6	0	0	0.0000	0	0.0000
	CLINCH RIVER 1	3,564	40,368	0.0883	190	16.7738
	CLINCH RIVER 2	573	11,012	0.0520	51	2.6537
	CLINCH RIVER 3	0	0	0.0000	0	0.0000
	DRBLK	56,004	211,711	0.2645	0	0.0000
	GLEN LYN 51	0	0	0.0000	0	0.0000
	GLEN LYN 52	0	0	0.0000	0	0.0000
	GLEN LYN 6	0	0	0.0000	0	0.0000
	KANAWHA RIVER 1	0	0	0.0000	0	0.0000
	KANAWHA RIVER 2	8,189	51,096	0.1603	461	73.8831
	MOUNTAINEER 1	153,389	672,845	0.2280	53	12.0825
	SPORN 1	1,228	27,446	0.0447	267	11.9462
	SPORN 3	196	3,873	0.0506	33	1.6700
	TOTAL	453,418	1,847,428	0.2454	1,290	184.3464
KPCO	BIG SANDY 1	13,949	88,094	0.1583	684	108.3061
	BIG SANDY 2	23,257	62,492	0.3722	411	152.9576
	ROCKPORT 1 (AEG)	44,269	140,844	0.3143	384	120.6958
	ROCKPORT 2 (AEG)	42,930	127,290	0.3373	341	115.0074
	TOTAL	124,405	418,720	0.2971	1,820	496.9669
I&M	ROCKPORT 1	103,276	328,594	0.3143	892	280.4364
	ROCKPORT 1 (AEG)	147,549	469,442	0.3143	1,275	400.6568
	ROCKPORT 2	100,188	297,024	0.3373	795	268.0590
	ROCKPORT 2 (AEG)	143,123	424,321	0.3373	1,135	382.9334
	TANNERS CREEK 1	0	0	0.0000	0	0.0000
	TANNERS CREEK 2	5,139	15,977	0.3216	80	25.7309
	TANNERS CREEK 3	6,774	50,651	0.1337	272	36.3787
	TANNERS CREEK 4	29,858	111,550	0.2677	835	223.5030
	TOTAL	535,907	1,697,559	0.3157	5,284	1,617.6982

ACTUAL: December 2012

AEP SYSTEM
ALLOWANCES CONSUMED FOR SALES
TO NON-AFFILIATED SYSTEMS (a)

		GENERATION ALLOCATED TO SALES TO NON-AFFILIATED SYSTEMS (MWh)	TOTAL GENERATION (MWh)	SYSTEM SALES ALLOCATION FACTOR	SO2 EMISSIONS (In Tons) (b)	SO2 EMISSION EXPENDED FOR SYSTEM SALES
		(1)	(2)	(3)=(1)/(2)	(4)	(5)=(3)*(4)
OPCO	AMOS 3	122,065	448,974	0.2719	116	31.5375
	CARDINAL 1	39,327	414,172	0.0950	364	34.5630
	CARDINAL 2	8,094	34,339	0.2357	84	19.7234
	CARDINAL 3	6,312	33,095	0.1907	3	0.5820
	CONESVILLE 1	0	0	0.0000	0	0.0000
	CONESVILLE 2	0	0	0.0000	0	0.0000
	CONESVILLE 3	1,737	30,012	0.0579	657	38.0251
	CONESVILLE 4	0	0	0.0000	0	0.0000
	CONESVILLE 5	23,695	95,382	0.2484	78	19.3769
	CONESVILLE 6	16,941	81,248	0.2085	72	15.0127
	DARBY 1	0	0	0.0000	0	0.0000
	DARBY 2	0	0	0.0000	0	0.0000
	DARBY 3	0	0	0.0000	0	0.0000
	DARBY 4	0	0	0.0000	0	0.0000
	DARBY 5	0	0	0.0000	0	0.0000
	DARBY 6	0	0	0.0000	0	0.0000
	GAVIN 1	207,892	661,883	0.3141	853	267.9203
	GAVIN 2	211,796	769,738	0.2752	1,072	294.9644
	KAMMER 1	1,336	11,269	0.1185	125	14.8161
	KAMMER 2	0	0	0.0000	0	0.0000
	KAMMER 3	5,627	63,776	0.0882	673	59.3793
	LAWRENCEBURG 1	37,507	156,536	0.2396	1	0.2396
	LAWRENCEBURG 2	45,434	178,496	0.2545	0	0.0000
	MITCHELL 1	93,763	357,265	0.2624	212	55.6389
	MITCHELL 2	111,851	468,921	0.2385	231	55.0999
	MUSKINGUM 1	0	0	0.0000	0	0.0000
	MUSKINGUM 2	0	0	0.0000	0	0.0000
	MUSKINGUM 3	3,186	53,423	0.0596	2,208	131.6790
	MUSKINGUM 4	0	0	0.0000	0	0.0000
	MUSKINGUM 5	21,438	135,809	0.1579	743	117.2876
	PICWAY 5	0	0	0.0000	0	0.0000
	SPORN 2	2,897	35,980	0.0805	324	26.0875
	SPORN 4	0	0	0.0000	0	0.0000
	SPORN 5	0	0	0.0000	0	0.0000
	STUART 1	28,668	89,364	0.3208	49	15.7191
	STUART 2	35,012	98,039	0.3571	42	14.9993
	STUART 3	34,361	91,613	0.3751	57	21.3791
	STUART 4	15,816	45,368	0.3486	25	8.7155
	WATERFORD	61,847	293,429	0.2108	0	0.0000
	WCBECKJORD 6	7,026	24,301	0.2891	452	130.6823
	ZIMMER 1	47,523	129,758	0.3662	242	88.6313
	TOTAL	1,191,152	4,802,190	0.2480	8,683	1,462.0598

NOTES: (a) As per Section 4.3 and Appendix E of the Interim Allowance Agreement.
(b) From Continuous Emission Monitoring System monthly data.

ACTUAL: December 2012

SYSTEM ACCOUNT
SUMMARY OF ENERGY SETTLEMENT
ADJUSTMENT TO ACCOUNT FOR
MARKET PRICE (1) vs. INVENTORY COST (2)
DIFFERENTIAL OF EMISSION ALLOWANCES

I. AEP EXTERNAL ENERGY (3)

	ACCOUNT 509		SOURCE ALLOCATION
	SO2 COST ($) (AS SUPPLIED) (1)	SO2 COST ($) (ADJUSTED) (2)	$ SO2 ADJUSTMENT (3)=(2)-(1)
APCO	351	3,822	3,471
KPCO	810	118,855	118,045
I&M	2,921	388,749	385,828
OPCO	2,504	177,012	174,508
CSP	0	0	0
AEP	6,586	688,438	681,852

	NOX COST ($) (AS SUPPLIED) (4)	NOX COST ($) (ADJUSTED) (5)	$ NOX ADJUSTMENT (6)=(5)-(4)
APCO	4,845	0	(4,845)
KPCO	5,321	1,556	(3,765)
I&M	25,459	23,660	(1,799)
OPCO	22,243	49	(22,193)
CSP	0	0	0
AEP	57,867	25,265	(32,602)

	SOURCE ALLOCATION (UNADJUSTED) (7)	SOURCE ALLOCATION (ADJUSTED) (8)=(7)+(3)+(6)
APCO	27,258,364	27,256,990
KPCO	3,920,820	4,035,100
I&M	20,017,242	20,401,271
OPCO	45,944,364	46,096,679
CSP	0	0
AEP	97,140,790	97,790,040

NOTES:

	SO2	NOX
(1) Market Price ($/Ton):	2.00	45.00
(2) APCO $/Ton:	20.73	0.00
KPCO $/Ton:	239.16	13.16
I&M $/Ton:	240.31	41.82
OPCO $/Ton:	121.07	0.10
CSP $/Ton:	0.00	0.00

(7) From Power Tracker report "Pool Flow Report - Off-System Allocation"

APPENDICES

SUPPORTING COST AND OPERATING DATA

SYNOPSIS OF CONTENTS

APPENDIX I

AMERICAN ELECTRIC POWER SYSTEM
MEMBER LOAD RATIO SUMMARY

MONTH ENDING 11/30/2012

OPERATING COMPANY PERCENTAGE
DECEMBER 2012

APPALACHIAN	KENTUCKY	INDIANA	OHIO	COLUMBUS
0.30372	0.06083	0.20861	0.42684	0.00000

Internal (MLR) MLR MONTHLY MAXIMUM
60-MINUTE INTEGRATED MEGAWATT DEMAND
EXCLUDE AEP SYSTEM SALES

		APPALACHIAN			KENTUCKY			INDIANA			OHIO			COLUMBUS		
MO/YR	TOTAL	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK	DA	HR	PEAK
11/12	17693	29	08	6092	29	08	1203	28	08	3427	28	20	6971	01	01	0
10/12	16465	29	18	5310	29	19	1046	31	12	3255	29	19	6854	01	01	0
09/12	19357	07	16	5637	05	16	1050	04	15	4044	06	16	8626	01	01	0
08/12	20653	02	16	5891	08	16	1138	03	16	4488	03	15	9136	01	01	0
07/12	21788	26	16	6302	26	16	1182	06	13	4726	18	13	9578	01	01	0
06/12	21820	29	16	6391	29	16	1183	28	16	4576	29	14	9670	01	01	0
05/12	18127	30	16	5177	03	13	1066	29	16	3762	25	16	8122	01	01	0
04/12	15827	12	07	4984	12	07	1071	11	07	3195	12	08	6577	01	01	0
03/12	17989	06	08	6084	06	08	1247	05	08	3392	05	21	7266	01	01	0
02/12	19030	13	08	6600	13	08	1340	13	08	3515	13	08	7575	01	01	0
01/12	19825	04	08	6881	04	08	1378	20	08	3686	13	11	7880	01	01	0
12/11	18348	12	08	6123	12	08	1272	12	08	3528	12	08	7425	01	01	0

Internal (MLR) MAXIMUM 60-MINUTE
INTEGRATED MW DEMAND EXPERIENCED
DURING PRECEDING 12-MONTHS
EXCLUDE AEP SYSTEM SALES

	TOTAL	APPALACHIAN	KENTUCKY	INDIANA	OHIO	COLUMBUS
	22655	6881	1378	4726	9670	0
DATE/TIME		01/04/12 HR 08	01/04/12 HR 08	07/06/12 HR 13	06/29/12 HR 14	01/01/12 HR 01

Notes:

Beginning with the January 2012 MLR Report, OPCo peak load for 2011 were restated to reflect the OP/CSP merger

The 2011 and Jan 2012 OP Peak loads have been restated to reflect Wyandot as a behind the meter load reducer effective with the OP/CSP merger

AP Peak Load was restated for January 2012 to add in correction of 4 MW for Glen Ferris

IM and OP Peak loads were restated for January 2012 to reflect corrected values for the Tilman-Haviland tie

OPCo Peak load was restated for June 2012 to reflect corrections from impact of Buckeye load in the MLR calculations.

APPENDIX II

ACTUAL: December 2012

SYSTEM PRIMARY CAPACITY

STATION	PRIMARY CAPACITY kW
APPALACHIAN POWER COMPANY	
Amos	2,033,000
Ceredo	482,000
Clinch River	700,000
Dresden	577,000
Glen Lyn	332,000
Kanawha River	400,000
Mountaineer	1,317,000
Sporn	295,000
Beech Ridge Wind Farm	28,000
Camp Grove Wind Farm	26,000
Fowler Ridge Wind Farm	29,000
Grand Ridge Wind Farm	32,000
TOTAL MEMBER PRIMARY CAPACITY (EXCLUDING HYDRO)	6,251,000
Smith Mountain (Hydro)	586,000
SEPA Capacity Agreement	4,000
Other Conventional Hydros	82,000
Summersville	28,000
TOTAL MEMBER PRIMARY CAPACITY	6,951,000
KENTUCKY POWER COMPANY	
Big Sandy	1,078,000
Rockport 1 (Purchase from AEG)	198,000
Rockport 2 (Purchase from AEG)	195,000
TOTAL MEMBER PRIMARY CAPACITY (EXCLUDING HYDRO)	1,471,000
TOTAL MEMBER PRIMARY CAPACITY	1,471,000
INDIANA MICHIGAN POWER COMPANY	
Cook	2,149,000
Rockport 1 (I&M owned)	660,000
Rockport 1 (Purchase from AEG)	461,000
Rockport 2 (I&M leased)	650,000
Rockport 2 (Purchase from AEG)	455,000
Tanners Creek	991,000
Fowler Ridge Wind Farm I	30,000
Fowler Ridge Wind Farm II	16,000
TOTAL MEMBER PRIMARY CAPACITY (EXCLUDING HYDRO)	5,412,000
Others (Hydro)	14,000
TOTAL MEMBER PRIMARY CAPACITY	5,426,000
OHIO POWER COMPANY	
Amos	867,000
Beckjord	52,000
Cardinal	592,000
Conesville	1,304,000
Darby	473,000
Gavin	2,638,000
Kammer	620,000
Lawrenceburg	1,155,000
Mitchell	1,560,000
Muskingum River	1,404,000
Picway	98,000
Sporn (1)	295,000
Stuart	600,000
Waterford	830,000
Zimmer	330,000
Fowler Ridge Wind Farm II	33,000
TOTAL MEMBER PRIMARY CAPACITY (EXCLUDING HYDRO)	12,851,000
Racine (Hydro)	25,000
TOTAL MEMBER PRIMARY CAPACITY	12,876,000
COLUMBUS SOUTHERN POWER COMPANY	
TOTAL MEMBER PRIMARY CAPACITY (EXCLUDING HYDRO)	0
TOTAL MEMBER PRIMARY CAPACITY	0
TOTAL SYSTEM PRIMARY CAPACITY	26,724,000

SOURCE: kW RATINGS ARE ESTABLISHED BY THE OPERATING COMMITTEE

(1) NOTE: Effective September 1, 2011 Sporn 5 has been removed from System Primary Capacity per the AEP East Operating Committee.

ACTUAL:
December 2012

MEMBER WEIGHTED AVERAGE INVESTMENT COSTS
AND MEMBER PRIMARY CAPACITY INVESTMENT RATES
YEAR 2012

Generating Stations Other than Hydro Classified as Part of Member Primary Capacity	kW Capability*** as of 12/31/2011 (1)	$ Installed Cost of Production Plant * as of 12/31/2011 (2)	Member Weighted Average Investment Cost $/kW (3)=(2)/(1)	Member Primary Capacity Investment Rate** $/kW/Month (4)=(3)*.0137
APPALACHIAN POWER COMPANY				
Amos	2,033,000	2,215,289,721		
Ceredo	482,000	204,121,936		
Clinch River	700,000	410,671,344		
Dresden	577,000	0		
Glen Lyn	332,000	154,548,200		
Kanawha River	400,000	190,892,250		
Mountaineer	1,317,000	1,532,237,122		
Sporn	295,000	137,234,338		
Beech Ridge Wind Farm	28,000	0		
Camp Grove Wind Farm	26,000	0		
Fowler Ridge Wind Farm	29,000	0		
Grand Ridge Wind Farm	32,000	0		
Appalachian Total	6,251,000	4,844,994,911	775.08	10.62
KENTUCKY POWER COMPANY				
Big Sandy	1,078,000	543,141,928		
Rockport 1 Purchased from AEG	198,000	199,440,113		
Rockport 2 Purchased from AEG	195,000	27,987,324		
Kentucky Total	1,471,000	770,569,365	523.84	7.18
INDIANA MICHIGAN POWER COMPANY				
Cook	2,149,000	2,287,934,996		
Rockport 1 Ownership Share	660,000	659,386,109		
Rockport 1 Purchased from AEG	461,000	465,360,265		
Rockport 2 Leased Shared	650,000	94,840,853		
Rockport 2 Purchased from AEG	455,000	65,303,755		
Tanners Creek	991,000	635,383,845		
Fowler Ridge Wind Farm I	30,000	0		
Fowler Ridge Wind Farm II	16,000	0		
Indiana Total	5,412,000	4,208,209,822	777.57	10.65
OHIO POWER COMPANY				
Amos	867,000	968,164,920		
Beckjord	52,000	18,905,947		
Cardinal	592,000	709,172,332		
Conesville	1,304,000	1,032,080,094		
Darby	473,000	190,619,023		
Gavin	2,638,000	1,918,085,097		
Kammer	620,000	342,094,193		
Lawrenceburg Purchased from AEG	1,155,000	702,738,795		
Mitchell	1,560,000	1,721,238,078		
Muskingum River	1,404,000	671,528,995		
Picway	98,000	43,971,118		
Sporn	295,000	151,907,552		
Stuart	600,000	527,599,296		
Waterford	830,000	214,147,258		
Zimmer	330,000	771,840,628		
Fowler Ridge Wind Farm II	33,000	0		
Ohio Total	12,851,000	9,984,093,326	776.91	10.64
COLUMBUS SOUHTHERN POWER COMPANY				
Fowler Ridge Wind Farm II	-	0		
Columbus Total	-	-	0.00	0.00

PRODUCTION EXPENSES INCURRED

GENERATION STATIONS ALLOCATED TO SYSTEM PRIMARY CAPACITY

	NET GENERATION MWh	TOTAL NET PRODUCTION EXPENSES ($)	FUEL A/C 501 ($)	MAINTENANCE ($)	FUEL A/C 151 ($)	FUEL A/C 152 ($)
APPALACHIAN POWER COMPANY						
GLEN LYN	0	(50,183)	(538,405)	161,409	(481,279)	(57,126)
SPORN (APCO)	31,319	2,548,017	1,743,564	361,579	1,629,975	113,589
KANAWHA RIVER	51,096	2,714,874	1,719,063	554,409	1,554,081	164,983
CLINCH RIVER	51,380	4,070,247	2,597,636	687,624	2,383,859	213,778
AMOS (APCO)	829,077	35,661,368	25,465,327	6,304,804	24,014,548	1,450,779
MOUNTAINEER	672,845	25,878,442	18,518,829	4,636,934	17,113,349	1,405,480
CEREDO	0	360,228	60,834	157,311	36,296	24,538
DRESDEN	211,711	7,122,356	5,993,323	417,628	5,964,861	28,462
BEECH RIDGE	18,917	0	0	0	0	0
CAMP GROVE	20,761	0	0	0	0	0
FOWLER RIDGE III	26,334	0	0	0	0	0
GRAND RIDGE II	12,312	0	0	0	0	0
GRAND RIDGE III	11,590	0	0	0	0	0
SUM	1,937,342	78,305,349	55,560,172	13,281,698	52,215,690	3,344,482
COAL CONVERSION	0	0	0	0	0	0
TOTAL	1,937,342	78,305,349	55,560,172	13,281,698	52,215,690	3,344,482
RATES:		32.106	28.678	3.428	26.952	1.726
KENTUCKY POWER COMPANY						
BIG SANDY	150,586	8,430,806	6,317,872	1,085,979	6,350,246	(32,373)
ROCKPORT 1 (AEG)	140,844	3,915,252	3,230,588	300,770	3,060,683	169,906
ROCKPORT 2 (AEG)	127,290	4,903,153	2,958,416	216,183	2,810,486	147,930
TOTAL	418,720	17,249,212	12,506,876	1,602,932	12,221,415	285,462
RATES:		31.784	29.870	1.914	29.188	0.682
INDIANA MICHIGAN POWER COMPANY						
TANNERS CREEK TOTAL	178,178	8,147,225	5,713,523	1,174,379	4,943,288	770,235
ROCKPORT 1 (OWNED SHARE)	469,442	13,049,785	10,767,755	1,002,485	10,201,449	566,306
ROCKPORT 1 (AEG)	328,594	9,134,422	7,537,076	701,707	7,140,680	396,396
ROCKPORT 2 (AEG)	297,024	11,441,230	6,903,296	504,451	6,558,110	345,186
ROCKPORT 2 (LEASED SHARE)	424,321	16,344,653	9,861,874	720,646	9,368,751	493,123
COOK	1,638,774	53,956,774	14,161,049	24,966,759	14,161,049	0
FOWLER RIDGE I	26,736	0	0	0	0	0
FOWLER RIDGE II	15,248	0	0	0	0	0
SUM	3,378,317	112,074,088	54,944,572	29,070,428	52,373,326	2,571,246
RATES:		20.567	16.264	4.303	15.503	0.761
OHIO POWER COMPANY						
SPORN (OPCO)	35,980	2,809,223	2,242,112	166,957	2,045,128	196,984
MUSKINGUM	189,232	9,606,738	8,364,890	1,248,613	7,984,125	380,765
KAMMER	75,045	4,632,775	3,398,355	1,485,134	3,113,334	285,021
CARDINAL (OPCO)	481,609	12,429,878	8,635,087	1,422,769	7,813,125	821,963
MITCHELL	826,186	29,725,855	24,843,053	3,392,669	23,969,931	873,123
AMOS (OPCO)	448,974	14,453,165	11,840,758	1,424,871	11,367,860	472,899
GAVIN	1,431,621	47,510,385	36,394,442	6,146,856	33,805,382	2,589,060
FOWLER RIDGE II	30,496	0	0	0	0	0
WYANDOT	466	0	0	0	0	0
CONESVILLE	206,642	15,847,814	9,198,629	4,048,201	8,334,436	864,192
PICWAY	0	121,183	41,680	30,854	35,304	6,376
BECKJORD	24,301	699,464	622,123	56,464	599,254	22,869
STUART	324,384	12,611,656	9,122,090	2,474,340	8,657,477	464,614
ZIMMER	129,758	5,468,087	4,235,273	596,718	4,062,600	172,673
WATERFORD	293,429	9,403,465	8,355,685	734,020	8,310,932	44,753
DARBY	0	(120,745)	23,940	80,821	2,962	20,978
LAWRENCEBURG	335,032	12,167,341	9,933,453	849,481	9,891,159	42,294
SUM	4,833,155	177,366,284	137,251,569	24,158,768	129,993,008	7,258,561
Capacity Deferral	0	(7,280,488)	0	0	0	0
TOTAL	4,833,155	170,085,796	137,251,569	24,158,768	129,993,008	7,258,561
RATES:		30.897	28.398	2.499	26.896	1.502
SYSTEM TOTAL	10,567,534	377,714,445	260,263,190	68,113,826	246,803,440	13,459,750

ACTUAL: December 2012

APPENDIX V

CALCULATION OF

PRIMARY ENERGY RATES AND PRIMARY CAPACITY FIXED OPERATING RATES

PRODUCTION EXPENSES OF GENERATION (EXCLUDING HYDRO) PRIMARY CAPACITY (FROM APPENDIX IV):

COMPANY	($) TOTAL NET PRODUCTION EXPENSE (*)	($) FUEL EXPENSE A/C 151 (*)	($) FUEL EXPENSE A/C 152	MAINTENANCE EXPENSE	($) ONE-HALF MAINTENANCE EXPENSE
	(1)	(2)	(3)	(4)	(5)
APCO	78,305,349	52,215,690	3,344,482	13,281,698	6,640,849
KPCO	17,249,212	12,221,415	285,462	1,602,932	801,466
I&M	112,074,088	52,373,326	2,571,246	29,070,428	14,535,214
OPCO	170,085,796	129,993,008	7,258,561	24,158,768	12,079,384
CSP	0	0	0	0	0
TOTAL	377,714,445	246,803,440	13,459,750	68,113,826	34,056,913

CALCULATION OF MEMBER PRIMARY RATES:

COMPANY	($) UNADJUSTED PART OF PRODUCTION EXPENSE	UNADJUSTED NET GENERATION MWh (APPENDIX IV)	ADJUSTED NET GENERATION (*) MWh (APPENDIX IV)	PRIMARY ENERGY RATE MILLS/kWh
	(6)=(3)+(5)	(7)	(8)	(9)=(5)/(7) +(2)/(8) +(3)/(7)
APCO	9,985,331	1,937,342	1,937,342	32.106
KPCO	1,086,928	418,720	418,720	31.783
I&M	17,106,460	3,378,317	3,378,317	20.566
OPCO	19,337,945	4,833,155	4,833,155	30.897
CSP	0	0	0	0.000
TOTAL	47,516,663	10,567,534	10,567,534	27.852

CALCULATION OF MEMBER PRIMARY CAPACITY FIXED OPERATING RATES:

COMPANY	($) TOTAL FIXED OPERATING EXPENSE	CAPABILITY OF GENERATION MEMBER PRIMARY CAPACITY, kW (APPENDIX II)	($/kW) MEMBER PRIMARY CAPACITY FIXED OPERATING RATE
	(10)=(1)-(2)-(6)	(11)	(12)=(10)/(11)
APCO	16,104,328	6,251,000	2.58
KPCO	3,940,869	1,471,000	2.68
I&M	42,594,302	5,412,000	7.87
OPCO	20,754,843	12,851,000	1.62
CSP	0	0	0.00
TOTAL	83,394,343	25,985,000	3.21

NOTE: * *Adjusted to exclude allocation of fuel costs (Acct. 151) associated with coal conversion services.*

ACTUAL: December 2012

SETTLEMENT WITH SYSTEM AGENT ASSOCIATED WITH MLR

ALLOCATIONS OF AEP SYSTEM RECEIPTS AND DELIVERIES

		ACTUAL SETTLEMENT		PREVIOUS ESTIMATE		ADJUSTMENT AMOUNT	
		AMOUNT DUE TO AGENT $ CHARGE	AMOUNT DUE FROM AGENT $ CREDIT	AMOUNT DUE TO AGENT $ CHARGE	AMOUNT DUE FROM AGENT $ CREDIT	AMOUNT DUE TO AGENT $ CHARGE	AMOUNT DUE FROM AGENT $ CREDIT
TRANSMISSION SERVICE (PURCHASES)	APCO	49,369	0	51,745	0	0	2,376
	KPCO	9,887	0	10,362	0	0	475
	I&M	33,908	0	35,542	0	0	1,634
	OPCO	0	93,164	0	97,649	4,485	0
	CSP	0	0	0	0	0	0
	TOTAL	93,164	93,164	97,649	97,649	4,485	4,485
NET AMOUNT DUE FOR ALL SYSTEM TRANSACTIONS (EXCEPT TRANS. SERVICE) (1)	APCO	0	29,509,633	0	29,507,841	0	1,793
	KPCO	0	5,910,283	0	5,909,923	0	359
	I&M	0	20,268,684	0	20,267,452	0	1,231
	OPCO	0	41,472,053	0	41,469,533	0	2,520
	CSP	0	0	0	0	0	0
	East. AEP (Co. 122)	97,160,653	0	97,154,750	0	5,903	0
	TOTAL	97,160,653	97,160,653	97,154,750	97,154,750	5,903	5,903
THIRD PARTY SALES (2)	APCO	1,921,333	2,908,389	1,921,231	3,055,650	163,761	16,399
	KPCO	384,811	582,500	384,790	611,995	32,800	3,284
	I&M	1,319,667	1,997,626	1,319,597	2,098,771	112,480	11,265
	OPCO	2,700,189	4,087,375	2,700,046	4,294,330	230,144	23,047
	CSP	0	0	0	0	0	0
	East. AEP (Co. 122)	9,575,891	6,325,999	10,060,746	6,325,664	53,994	539,184
	TOTAL	15,901,890	15,901,890	16,386,410	16,386,410	593,178	593,178
GROSS TOTAL	APCO	1,921,333	32,418,023	1,921,231	32,563,491	163,761	18,191
	KPCO	384,811	6,492,782	384,790	6,521,918	32,800	3,643
	I&M	1,319,667	22,266,310	1,319,597	22,366,223	112,480	12,496
	OPCO	2,700,189	45,559,428	2,700,046	45,763,864	230,144	25,566
	CSP	0	0	0	0	0	0
	East. AEP (Co. 122)	106,736,544	6,325,999	107,215,496	6,325,664	59,897	539,184
	TOTAL	113,062,543	113,062,543	113,541,160	113,541,160	599,081	599,081
NET TOTAL	APCO	0	30,496,690	0	30,642,260	145,569	0
	KPCO	0	6,107,972	0	6,137,128	29,156	0
	I&M	0	20,946,643	0	21,046,627	99,984	0
	OPCO	0	42,859,240	0	43,063,818	204,578	0
	CSP	0	0	0	0	0	0
	East. AEP (Co. 122)	100,410,544	0	100,889,832	0	0	479,287
	TOTAL	100,410,544	100,410,544	100,889,832	100,889,832	479,287	479,287

NOTES: (1) Source is Power Tracker reports, Pool Flow and Purchase Power with Demand Charge and Adjustments
(2) Source is Appendix VII.

ACTUAL: December 2012 AEP SYSTEM MLR ALLOCATION OF EXPENSES FOR TRANSMISSION SERVICE

Pwr Code	Customer		ACCT	CO. AGNT	ACTUAL BILL	MLR APCO 30.372%	KPCO 6.083%	I&M 20.861%	OPCO 42.684%	CSP 0.000%	Total 100.00%	AMOUNT DUE (TO)/FROM AGENT APCO	KPCO	I&M	OPCO	CSP	NET
	Totals				162,547	49,369	9,887	33,908	69,382	-	162,546	(49,369)	(9,887)	(33,908)	93,164	-	-
ACCOUNTS PAYABLE																	
CPLC	Progress Energy		4470066	07	451	137	27	94	193	0	451	(137)	(27)	(94)	258	-	-
DUKE2	Duke Power Company		4470066	07	639	194	39	133	273	0	639	(194)	(39)	(133)	366	-	-
DEOI2	Duke Energy Ohio	(1)	4470006	07	5,095	1,547	310	1,063	2,175	0	5,095	(1,547)	(310)	(1,063)	2,920	-	-
DTE	DTE Energy Trading, Inc.	(1)	4470006	07	14,018	4,258	853	2,924	5,983	0	14,018	(4,258)	(853)	(2,924)	8,035	-	-
ENTE	Entergy Power Serv		4470066	07	3,486	1,059	212	727	1,488	0	3,486	(1,059)	(212)	(727)	1,998	-	-
MISO Trading	Midwest Trading	(1)	4470006	07	138,851	42,172	8,446	28,966	59,267	0	138,851	(42,172)	(8,446)	(28,966)	79,584	-	-
TVAM	TVA Bulk Power Trading		4470066	07	6	2	0	1	3	0	6	(2)	-	(1)	3	-	-

APCO	KPCO	I&M	OPCO	CSP
136.97772	27.43433	94.08311	192.50484	0.00000
194.02241	38.85942	133.26424	272.67393	0.00000
1,547.57489	309.95318	1,062.95139	2,174.92054	0.00000
4,257.59859	852.72528	2,924.33044	5,983.51568	0.00000
1,058.73147	212.04608	727.18943	1,487.91302	0.00000
42,171.82268	8,446.30572	28,965.70502	59,267.15657	0.00000
1.92862	0.38627	1.32467	2.71043	0.00000

Notes: (1) The AEP System MLR Allocation of Pass-Trough Receipts for Transmission Service section is no longer included on APPVI PG2 as this activity is recorded from the Off System spreadsheet.

ACTUAL: December 2012

SETTLEMENT WITH SYSTEM AGENT ASSOCIATED
WITH MLR ALLOCATIONS OF AEP SYSTEM
OFF-SYSTEM THIRD PARTY

			MWh		($)	
					ALLOCATION BY MLR	
			PURCHASES	SALES	TOTAL COSTS TO BE BOOKED	TOTAL REVENUES TO BE BOOKED
	ENERGY	(1)	ACCT. 4470.010	ACCT. 4470.006	ACCT. 4470.010	ACCT. 4470.006
I.	ACTUAL	APCO	141,737	142,434	4,774,300	6,826,112
	THIS MONTH	KPCO	28,410	28,514	956,212	1,367,155
		I&M	97,254	97,804	3,279,227	4,688,514
		OPCO	199,496	200,505	6,709,674	9,593,238
		CSP	0	0	0	0
		TOTAL	466,897	469,257	15,719,413	22,475,019
II.	PREVIOUS	APCO	140,520	143,892	4,737,925	6,773,516
	ESTIMATE	KPCO	28,166	28,807	948,928	1,356,621
		I&M	96,418	98,806	3,254,244	4,652,388
		OPCO	197,790	202,554	6,658,554	9,519,320
		CSP	0	0	0	0
		TOTAL	462,893	474,060	15,599,651	22,301,845
III.	ADJUSTMENT	APCO	1,217	(1,458)	36,375	52,596
	(I-II)	KPCO	244	(293)	7,285	10,534
		I&M	836	(1,002)	24,983	36,126
		OPCO	1,706	(2,049)	51,119	73,918
		CSP	0	0	0	0
		TOTAL	4,004	(4,803)	119,761	173,173

					TOTAL COSTS TO BE BOOKED	TOTAL REVENUES TO BE BOOKED
	EXERCISED OPTIONS & PREMIUMS	(2)	ACCT. 4470.011	ACCT. 4470.007	ACCT. 4470.011	ACCT. 4470.007
I.	ACTUAL	APCO	0	0	0	0
	THIS MONTH	KPCO	0	0	0	0
		I&M	0	0	0	0
		OPCO	0	0	0	0
		CSP	0	0	0	0
		TOTAL	0	0	0	0
II.	PREVIOUS	APCO	0	0	0	0
	ESTIMATE	KPCO	0	0	0	0
		I&M	0	0	0	0
		OPCO	0	0	0	0
		CSP	0	0	0	0
		TOTAL	0	0	0	0
III.	ADJUSTMENT	APCO	0	0	0	0
	(I-II)	KPCO	0	0	0	0
		I&M	0	0	0	0
		OPCO	0	0	0	0
		CSP	0	0	0	0
		TOTAL	0	0	0	0

ACTUAL: December 2012

SETTLEMENT WITH SYSTEM AGENT ASSOCIATED
WITH MLR ALLOCATIONS OF AEP SYSTEM
OFF-SYSTEM THIRD PARTY

BELOW THE LINE		ALLOCATION BY MLR (MWh) PHYSICAL BOOKOUT PURCHASES 4210.032	ALLOCATION BY MLR (MWh) GAIN REVENUES 4210.031	ALLOCATION BY MLR ($) PHYSICAL BOOKOUT PURCHASES 4210.032	ALLOCATION BY MLR ($) GAIN REVENUES 4210.031
ACTUAL THIS MONTH	APCO	7	0	268	0
	KPCO	1	0	54	0
	I&M	5	0	184	0
	OPCO	9	0	376	0
	CSP	0	0	0	0
	TOTAL	22	0	881	0
PREVIOUS ESTIMATE	APCO	0	0	0	0
	KPCO	0	0	0	0
	I&M	0	0	0	0
	OPCO	0	0	0	0
	CSP	0	0	0	0
	TOTAL	0	0	0	0
ADJUSTMENT (I-II)	APCO	7	0	268	0
	KPCO	1	0	54	0
	I&M	5	0	184	0
	OPCO	9	0	376	0
	CSP	0	0	0	0
	TOTAL	22	0	881	0

BROKERS' COMMISSIONS (3)		ALLOCATION BY MLR ($) RENEWABLE ENERGY CREDIT COMMISSIONS ACCT. 5570.007	BROKER'S COMMISSIONS ACCT.4470.143	BROKER'S COMMISSIONS ACCT.5550.099	ALLOCATION BY MLR ($) PURCHASE COSTS ACCT. 4470.010	ALLOCATION BY MLR ($) SALES REVENUES ACCT. 4470.006
ACTUAL THIS MONTH	APCO	0	0	51	8,139	(1,498)
	KPCO	0	0	10	1,630	(300)
	I&M	0	0	35	5,591	(1,029)
	OPCO	0	0	72	11,439	(2,105)
	CSP	0	0	0	0	0
	TOTAL	0	0	168	26,799	(4,932)
PREVIOUS ESTIMATE	APCO	0	0	51	8,128	(1,498)
	KPCO	0	0	10	1,628	(300)
	I&M	0	0	35	5,583	(1,029)
	OPCO	0	0	72	11,424	(2,105)
	CSP	0	0	0	0	0
	TOTAL	0	0	168	26,763	(4,932)
ADJUSTMENT (I-II)	APCO	0	0	0	11	0
	KPCO	0	0	0	2	0
	I&M	0	0	0	8	0
	OPCO	0	0	0	15	0
	CSP	0	0	0	0	0
	TOTAL	0	0	0	36	0

ACTUAL: December 2012

SETTLEMENT WITH SYSTEM AGENT ASSOCIATED
WITH MLR ALLOCATIONS OF AEP SYSTEM
OFF-SYSTEM THIRD PARTY

PJM NON-ECR ENERGY		PJM NON-ECR PURCHASES - LSE MWH TOTAL COSTS TO BE BOOKED Act. 5550.001	PJM NON-ECR PURCHASES - LSE $ TOTAL COSTS TO BE BOOKED Act. 5550.001	POWER SWAPS TOTAL NET TO BE BOOKED Act. 5550.099	($) TOTAL SWAPS TOTAL NET TO BE BOOKED Act. 4470.143	TOTAL NET TO BE BOOKED Act. 4470.082
I. ACTUAL THIS MONTH	APCO	0	0	292,420	174	(1,619,131)
	KPCO	0	0	58,567	35	(324,285)
	I&M	0	0	200,849	119	(1,112,099)
	OPCO	0	0	410,960	245	(2,275,482)
	CSP	0	0	0	0	0
	TOTAL	0	0	962,796	573	(5,330,996)
II. PREVIOUS ESTIMATE	APCO	0	0	292,423	0	(1,619,131)
	KPCO	0	0	58,567	0	(324,285)
	I&M	0	0	200,850	0	(1,112,099)
	OPCO	0	0	410,963	0	(2,275,482)
	CSP	0	0	0	0	0
	TOTAL	0	0	962,804	0	(5,330,997)
III. ADJUSTMENT (I-II)	APCO	0	0	(2)	174	0
	KPCO	0	0	(0)	35	0
	I&M	0	0	(2)	119	0
	OPCO	0	0	(3)	245	0
	CSP	0	0	0	0	0
	TOTAL	0	0	(8)	573	1

PJM NON-ECR PURCHASES-OSS
NON-ECR PHYSICAL SALES-OSS

PJM NON-ECR ENERGY		MWh PURCHASES Act. 5550.107	PURCHASES Act. 5550.099	PURCHASES Act. 4470.131	SALES Act. 4470.112	SALES 4470.170	RENEWABLE ENERGY CREDITS Act. 5570.007	COSTS TO BE BOOKED Act. 5550.088	COSTS TO BE BOOKED Act. 5550.023
I. ACTUAL THIS MONTH	APCO	0	66,514	30	5,213	59,114	489	0	0
	KPCO	0	13,317	6	1,051	11,840	98	0	0
	I&M	0	45,679	21	3,571	40,601	336	0	0
	OPCO	0	93,473	43	7,305	83,078	688	0	0
	CSP	0	0	0	0	0	0	0	0
	TOTAL	0	218,983	100	17,140	194,633	1,611	0	0
II. PREVIOUS ESTIMATE	APCO	0	66,514	30	5,504	58,426	489	0	0
	KPCO	0	13,317	6	1,109	11,702	98	0	
	I&M	0	45,679	21	3,771	40,129	336	0	
	OPCO	0	93,473	43	7,716	82,110	688	0	
	CSP	0	0	0	0	0	0	0	
	TOTAL	0	218,983	100	18,100	192,367	1,611	0	
III. ADJUSTMENT (I-II)	APCO	0	0	(0)	(291)	688	0	0	
	KPCO	0	0	(0)	(58)	138	0	0	
	I&M	0	(0)	0	(200)	472	0	0	
	OPCO	0	(0)	0	(411)	968	0	0	
	CSP	0	0	0	0	0	0	0	
	TOTAL	0	(0)	0	(960)	2,266	0	0	

($)

COSTS TO BE BOOKED Act. 5550.099	COSTS TO BE BOOKED Act. 5550.100	COSTS TO BE BOOKED Act. 5550.107	COSTS TO BE BOOKED Act. 5614.008	COSTS TO BE BOOKED Act. 4470.131	COSTS TO BE BOOKED Act. 4470.099	REVENUES TO BE BOOKED Act. 4470.112	REVENUES TO BE BOOKED Act. 4470.170	REVENUES TO BE BOOKED Act. 4470.002
2,107,216	12,708	133,832	0	804	(85,056)	181,071	3,015,541	(170,042)
422,041	2,545	26,804	0	161	(17,035)	36,266	603,962	(34,057)
1,447,340	8,729	91,923	0	552	(58,421)	124,369	2,071,224	(116,794)
2,961,424	17,860	188,085	0	1,130	(119,535)	254,473	4,237,962	(238,973)
0	0	0	0	0	0	0	0	0
6,938,021	41,842	440,644	0	2,647	(280,048)	596,178	9,928,689	(559,865)
2,091,118	13,097	133,203	0	786	(85,059)	191,232	2,982,461	0
418,815	2,623	26,678	0	157	(17,036)	38,301	597,337	
1,436,284	8,996	91,491	0	540	(58,423)	131,348	2,048,503	
2,938,801	18,406	187,200	0	1,105	(119,540)	268,753	4,191,472	
0	0	0	0	0	0	0	0	
6,885,018	43,121	438,572	0	2,589	(280,057)	629,634	9,819,772	
16,098	(389)	629	0	18	3	(10,161)	33,080	(170,042)
3,225	(78)	126	0	4	1	(2,035)	6,625	(34,057)
11,057	(267)	432	0	12	2	(6,979)	22,721	(116,794)
22,623	(546)	884	0	25	4	(14,280)	46,490	(238,973)
0	0	0	0	0	0	0	0	
53,003	(1,279)	2,072	0	58	10	(33,456)	108,917	(559,865)

COST TO BE BOOKED Act. 5650.002	Total PJM/MISO Non-ECR Energy (Revenue - Cost)
0	856,577
0	171,557
0	588,340
0	1,203,811
0	0
0	2,820,285
0	1,020,059
0	204,301
0	700,627
0	1,433,564
0	0
0	3,358,552
0	(163,482)
0	(32,744)
0	(112,288)
0	(229,753)
0	0
0	(538,267)

ACTUAL: December 2012

SETTLEMENT WITH SYSTEM AGENT ASSOCIATED
WITH MLR ALLOCATIONS OF AEP SYSTEM
BOOKOUTS AND OPTIONS

		ACTUAL SETTLEMENT		PREVIOUS ESTIMATE		ADJUSTMENT AMOUNT	
		AMOUNT DUE TO AGENT $ CHARGE	AMOUNT DUE FROM AGENT $ CREDIT	AMOUNT DUE TO AGENT $ CHARGE	AMOUNT DUE FROM AGENT $ CREDIT	AMOUNT DUE TO AGENT $ CHARGE	AMOUNT DUE FROM AGENT $ CREDIT
THIRD PARTY SALES (1)	APCO	0	2,051,813	0	2,035,591	0	16,222
	KPCO	0	410,942	0	407,693	0	3,249
	I&M	0	1,409,287	0	1,398,144	0	11,143
	OPCO	0	2,883,564	0	2,860,766	0	22,798
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	6,755,606	0	6,702,194	0	53,412	0
	TOTAL	6,755,606	6,755,606	6,702,194	6,702,194	53,412	53,412
EXERCISED OPTIONS & PREMIUMS (2)	APCO	0	0	0	0	0	0
	KPCO	0	0	0	0	0	0
	I&M	0	0	0	0	0	0
	OPCO	0	0	0	0	0	0
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	0	0	0	0	0	0
	TOTAL	0	0	0	0	0	0
BELOW THE LINE	APCO	268	0	0	0	268	0
	KPCO	54	0	0	0	54	0
	I&M	184	0	0	0	184	0
	OPCO	376	0	0	0	376	0
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	0	881	0	0	0	881
	TOTAL	881	881	0	0	881	881
BROKERS' COMMISSIONS (3)	APCO	9,688	0	9,677	0	11	0
	KPCO	1,940	0	1,938	0	2	0
	I&M	6,655	0	6,647	0	8	0
	OPCO	13,616	0	13,601	0	15	0
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	0	31,899	0	31,863	0	36
	TOTAL	31,899	31,899	31,863	31,863	36	36
POWER SWAPS	APCO	1,911,377	0	1,911,554	0	0	177
	KPCO	382,817	0	382,852	0	0	35
	I&M	1,312,828	0	1,312,950	0	0	121
	OPCO	2,686,197	0	2,686,445	0	0	248
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	0	6,293,219	0	6,293,801	582	0
	TOTAL	6,293,219	6,293,219	6,293,801	6,293,801	582	582
PJM/MISO NON-ECR ENERGY	APCO	0	856,577	0	1,020,059	163,482	0
	KPCO	0	171,557	0	204,301	32,744	0
	I&M	0	588,340	0	700,627	112,288	0
	OPCO	0	1,203,811	0	1,433,564	229,753	0
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	2,820,285	0	3,358,552	0	0	538,267
	TOTAL	2,820,285	2,820,285	3,358,552	3,358,552	538,267	538,267
NET BOOKOUTS, OPTIONS, BROKERS' COMMISSIONS, SWAPS & PJM NON-ECR ENERGY	APCO	1,921,333	2,908,389	1,921,231	3,055,650	163,761	16,399
	KPCO	384,811	582,500	384,790	611,995	32,800	3,284
	I&M	1,319,667	1,997,626	1,319,597	2,098,771	112,480	11,265
	OPCO	2,700,189	4,087,375	2,700,046	4,294,330	230,144	23,047
	CSP	0	0	0	0	0	0
	East. AEP (Co.122)	9,575,891	6,325,999	10,060,746	6,325,664	53,994	539,184
	TOTAL	15,901,890	15,901,890	16,386,410	16,386,410	593,178	593,178

NOTES:

(1) Power that did not enter into nor did it flow out of the AEP System, and is not included in the ECR/MLR report.

(2) Sold in previous period(s) and exercised in: December 2012

(3) Actual commissions paid in: December 2012

PJM CHARGES TRANSFERRED FROM nMARKET to AEE

PJM CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT	AEP AMT TOTAL
'EPSCG							
'M Allocations GL Submit Summary							
Total of PJM Non -ECR MISC Charges	Various	5,796,001	1,163,512	3,988,037	8,154,040	-	19,101,589
PJM Admin Fees							
Schedule 9 & 10	5614000	24,764	4,960	17,009	34,803	-	81,537
Schedule 9 & 10	5614001	374,662	75,039	257,337	526,540	-	1,233,577
Schedule 9 & 10	5618000	1,735	347	1,191	2,438	-	5,711
Schedule 9 & 10	5618001	26,244	5,256	18,026	36,882	-	86,408
Schedule 9 & 10	5757000	26,247	5,257	18,027	36,886	-	86,417
Schedule 9 & 10	5757001	397,085	79,529	272,738	558,053	-	1,307,405
Schedule 9 & 10	5618000	4,284	858	2,943	6,021	-	14,107
Schedule 9 & 10	5618001	64,819	12,982	44,521	91,096	-	213,418
Schedule 9 & 10	5618000	5,424	1,086	3,726	7,623	-	17,859
Schedule 9 & 10	5618001	82,063	16,436	56,365	115,329	-	270,193
Schedule 9 MMU	5757000	1,730	346	1,188	2,431	-	5,695
Schedule 9 MMU	5757001	26,168	5,241	17,974	36,776	-	86,158
PJM Affiliate Entry							
Network Integration Transmission Service Charge	4470107	(1)	(0)	(1)	(2)	-	(4)
Transmission Owner Scheduling, System...	4470110	876	175	601	1,231	-	2,883
Power Factor Charges	5550039	139	28	95	195	-	457
Other Supporting Facilities Charge	4470107	(137)	(27)	(94)	(193)	-	(451)
Invoice Adjustment - Spot Energy Sales	4470124	-	-	-	-	-	-
Allocation of Generation Activity on PJM Transmission Invoice							
Balancing Spot Market Energy	4470115	-	-	-	-	-	-
Incremental Implicit Congestion -OSS	4470126	-	-	-	-	-	-
Implicit Congestion - LSE	4470093	(10,550)	(2,113)	(7,246)	(14,827)	-	(34,736)
Inadvertent - OSS	5550039	-	-	-	-	-	-
Inadvertent - LSE	5550040	-	-	-	-	-	-
Misc Credits	4470107	0	-	0	0	-	0
Meter Correction - LSE	4470116	(285,451)	(57,171)	(196,062)	(401,165)	-	(939,849)
Incremental Implicit Congestion -LSE (Correction of Reversal of June 2011 Entry)	4470093	-	-	-	-	-	-
Incremental Implicit Congestion -OSS (Corrected July Correction of June 2011 Entry)	4470126	-	-	-	-	-	-
PJM Invoice Adjustment							
Spot Energy Sales (ECR)	4470124					-	-
Day-ahead Operating Reserve LSE (AUB)	4470203					-	-
Day-ahead Operating Reserve OSS (AUB)	4470098					-	-
Day-ahead Operating Reserve OSS (BCK)	4470141					-	-
Other Supporting Facilities reclass (BCK)	4470141					-	-
Other Supporting Facilities reclass (BCK)	4470126	0	0	0	0	-	0
Planning Period Congestion Uplift (BCK)	4470141	-	-	-	-	-	-
Planning Period Congestion Uplift (BCK)	4470126	-	-	-	-	-	-
Load Management Test Failure (BCK)	4470141	-	-	-	-	-	-
Non-Firm Point-to-Point Transmission Service OSS (SCG)	4470106	10,117	2,026	6,949	14,218	-	33,310
ay-ahead Operating Reserve (OSS BCK)	4470141	(10,117)	(2,026)	(6,949)	(14,218)	-	(33,310)
ansmission Congestion Target Credit OSS (BCK)	4470174	-	-	-	-	-	-
Day-ahead Operating Reserve (LSE SCG)	4470203	-	-	-	-	-	-
Day-ahead Operating Reserve (OSS SCG)	4470098	-	-	-	-	-	-
CT Lost Opportunity Cost Allocation LSE (SCG)	4470203	92	18	63	129	-	302
CT Lost Opportunity Cost Allocation OSS (SCG)	4470098	-	-	-	-	-	-
CT Lost Opportunity Cost Allocation OSS (AUB & OCG)	4470098	-	-	-	-	-	-
CT Lost Opportunity Cost Allocation LSE (AUB, APD,CSD, IMD,OPD,OCG)	4470203	-	-	-	-	-	-
CT Lost Opportunity Cost Allocation OSS (BCK)	4470141	-	-	-	-	-	-
Non-Synchronized Reserve (BCK)	4470141	(874)	(175)	(600)	(1,228)	-	(2,877)
Synchronized Reserve (LSE AUB)	5550083	(58)	(12)	(40)	(81)	-	(190)
PJM Annual Membership Fee (LSE AEPSCG)	4470203	(33)	(7)	(22)	(46)	-	(108)
PJM Annual Membership Fee OSS (AEPSCG)	4470098	(550)	(110)	(378)	(773)	-	(1,811)
Meter Error Correction Allocation Charge OSS (BCK)	4470141	(40)	(8)	(28)	(57)	-	(133)
Meter Error Correction Charge OSS (SCG)	4470115	-	-	-	-	-	-
Meter Error Correction Charge LSE (SCG)	4470116	-	-	-	-	-	-
Load Response Charge Allocation (BCK)	4470141	-	-	-	-	-	-
Load Response Charge Allocation LSE (SCG & AUB)	4470207	-	-	-	-	-	-
Load Response Charge Allocation OSS (SCG & AUB)	4470206	-	-	-	-	-	-
Balancing Operating Reserve for Load Response LSE (SCG)	4470203	-	-	-	-	-	-
Balancing Operating Reserve for Load Response OSS (SCG)	4470098	-	-	-	-	-	-
Incremental Capacity Transfer Rights (OSS BCK)	4470141	1,226	246	842	1,723	-	4,037
Incremental Capacity Transfer Rights (OSS SCG & AUB)	5650012	13,255	2,655	9,104	18,628	-	43,641
Synchronized Reserve ADJ (OSS MON, OCG & PMP)	5550083	876	175	602	1,231	-	2,885
Firm Point-to-Point Transmission Service OSS (BCK)	4470141	-	-	-	-	-	-
Firm Point-to-Point Transmission Service LSE (AEPSCG)	4561005	-	-	-	-	-	-
Non-Firm Point-to-Point Transmission Service LSE (AUB)	4561005	-	-	-	-	-	-
Non-Firm Point-to-Point Transmission Service OSS (BCK)	4470141	-	-	-	-	-	-
Non-Firm Point-to-Point Transmission Service LSE (AEPSCG)	4561005	-	-	-	-	-	-
Congestion & Loss on Load Response	4470093	-	-	-	-	-	-
Demand Resource and ILR Compliance Penalty OSS (SCG)	4470099	-	-	-	-	-	-
Transmission Loss Credit LSE (MON & OCG)	4470208	-	-	-	-	-	-
RPM Auction Credit OSS (SCG)	4470099	-	-	-	-	-	-
Balancing Operating Reserve (LSE)	4470202	-	-	-	-	-	-
Balancing Operating Reserve (LSE)	4470202	-	-	-	-	-	-
Balancing Operating Reserve (OSS)	4470098	-	-	-	-	-	-
Balancing Operating Reserve (OSS)	4470098	-	-	-	-	-	-
Balancing Operating Reserve (LSE - KAMMER)	4470202	-	-	-	-	-	-
CRES Capacity Charge							-
CRES Capacity Charge (OP)	4470099	-	-	-	(1,789,715)	-	(1,789,715)
CRES Capacity Charge (AEPEP)	4470217	-	-	-	(31,029)	-	(31,029)
CRES Capacity Charge (Blue Star)	4470217	-	-	-	(509,734)	-	(509,734)
CRES Capacity Charge (MI)	4470099	-	-	-	-	-	-
PJM TEA Charge Reclass (MLR)							
'ansmission Enhancement Charge	5650012	(1,253,990)	(251,153)	(861,303)	(1,762,324)	-	(4,128,771)
TO Start-up Cost Recovery Charge	4561002	(40,988)	(9,877)	(32,559)	(62,908)	-	(146,333)
Expansion Cost Recovery Charge	4561003	(24,926)	(6,007)	(19,800)	(38,257)	-	(88,990)
Firm/Non-Firm Pt to Pt Transmission Service Credit	4561005	267,060	53,488	183,430	375,319	-	879,298
PJM TEA Charge Reclass (12CP)							
Transmission Enhancement Charge	5650012	1,418,935	278,358	722,855	1,129,522	-	3,549,671
RTO Start-up Cost Recovery Charge	4561002	58,495	11,475	29,799	46,564	-	146,333
Expansion Cost Recovery Charge	4561003	35,573	6,978	18,122	28,317	-	88,990

Firm/Non-Firm Pt to Pt Transmission Service Credit	4561005	(328,191)	(64,382)	(167,192)	(261,251)	-	(821,016)
Firm /Non-Firm Pt to Pt Charges (Auburn)	4470150	40,411	2,867	150,422	-	-	193,700
PJM TEA PPAs for July,August,September,October and November 2012	5650012	21,638	(25,229)	(65,517)	(166,798)	-	(235,905)
TOTAL PJM CHARGES TRANSFERRED FROM nMARKET TO AEE (ACTUAL)		6,744,013	1,311,042	4,464,177	6,171,390	-	18,690,621
TOTAL PJM CHARGES TRANSFERRED FROM nMARKET TO AEE (ESTIMATED)		6,897,795	1,371,133	4,652,096	6,572,399	-	19,493,423
TOTAL PJM CHARGES TRANSFERRED FROM nMARKET TO AEE (ADJUSTMENT)	(1)	(153,782)	(60,092)	(187,919)	(401,009)	-	(802,802)

PJM NON-ECR CHARGES FROM INVOICE - COUNTERPARTY BUCKEYE

PJM CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT	AEP AMT TOTAL	PJM CHARGES FOR EAST ZONE SIA
PJM Allocations GL Submit Summary								
TOTAL PJM-BUCKEYE NON-ECR FROM INVOICE (1)	Various	1,265,590	253,653	869,741	1,779,193	-	4,168,176	5,052,150
TOTAL PJM CHARGES (NON-ECR) FROM INVOICE (ACTUAL)		1,265,590	253,653	869,741	1,779,193	-	4,168,176	
TOTAL PJM CHARGES (NON-ECR) FROM INVOICE (ESTIMATED)		1,226,282	245,746	842,650	1,723,839	-	4,038,517	
TOTAL PJM CHARGES TRANSFERRED FROM nMARKET TO AEE (ADJUSTMENT)	(1)	39,308	7,907	27,091	55,354	-	129,660	

CHARGE DESCRIPTION	ACCOUNT NO.	AP AMT	KP AMT	IM AMT	OP AMT	CS AMT		
PJM Allocations GL Submit Summary								
**Includes all particpants except SCG and BCK	Various	140,900	28,232	96,808	198,054	-	463,993.22	1,148,592
Buckeye GL Entries								
Buckeye (BCK)								
Capacity Credit Market	4470099	-	-	-	-	-	-	MAKE SURE THAT
PJM Service Fee	4470143	-	-	-	-	-	-	MAKE SURE THAT
Reactive Supply and Voltage Control Credit (Expense)	5550075	45,284	9,070	31,103	63,641	-	149,098.25	MAKE SURE THAT
Regulation Credit (Expense)	5550079	18,482	3,702	12,695	25,974	-	60,852.86	MAKE SURE THAT
Spinning Reserve - Credit	5550084	128	26	88	180	-	421.05	MAKE SURE THAT
Buckeye Pass-Through	4470141	(1,701,404)	(340,940)	(1,169,079)	(2,391,674)	-	(5,603,097.41)	MAKE SURE THAT
Transmission Loss Credit	4470206	-	-	-	-	-	-	MAKE SURE THAT
TOTAL OFFSET OF PASS-THROUGH CHARGES (1)		(1,496,610)	(299,911)	(1,028,386)	(2,103,825)	-	(4,928,732)	
TOTAL OFFSET OF PASS-THROUGH CHARGES (ESTIMATED)		(1,417,047)	(283,944)	(973,652)	(1,991,906)	-	(4,666,550)	
TOTAL OFFSET OF PASS-THROUGH CHARGES (ADJUSTMENT)	(1)	(79,563)	(15,967)	(54,733)	(111,919)	-	(262,182)	

ESTIMATED: December 2012

Allocation of 60 day PJM Load Reconciliation Period adjustment fc

		October MLR				0 30326
	Account	Account	Dr/(Cr)			APCo
MWh	34,747			MWh		10,537
Dollars	$ 1,758,905				$	533,406
	PJM Sales Revenue - Prod Cost	4470103	Cr		$	311,073
	PJM Sales Margin	4470089	Cr		$	222,333
	Total PJM Revenues from 60 Day Rec				$	533,406
	PJM Sales Revenue - Fuel Cost	Fuel			$	277,648

	Account	Account	Dr/Cr			APCo
	PJM Pool Purchases	5550102	Dr	MWh		10,537
	PJM Pool Purchases	5550102	Dr		$	311,073
	PJM Pool Purchases	Fuel			$	277,648
	PJM Pool Sales	4470128	Cr	MWh		-
	PJM Pool Sales	4470128	Cr		$	-
	PJM Pool Sales	Fuel			$	-
	NER Impact - Net MW					-
	NER Impact - Net Dollars				$	-

ADJUSTMENT: November 2012

Allocation of 60 day PJM Load Reconciliation Period adjustment for
Prior Month True-up: Adjustment to amou

		September MLR				0 30314
	Account	Account	Dr/(Cr)			APCo
MWh	0			MWh		0
Dollars	$ (0)				$	(0)
	PJM Sales Revenue - Prod Cost	4470103	Cr		$	-
	PJM Sales Margin	4470089	Cr		$	(0)
	Total PJM Revenues from 60 Day Rec				$	(0)
	PJM Sales Revenue - Fuel Cost	Fuel			$	-

	Account	Account	Dr/Cr			APCo
	PJM Pool Purchases	5550102	Dr	MWh		0
	PJM Pool Purchases	5550102	Dr		$	-
	PJM Pool Purchases	Fuel			$	-
	PJM Pool Sales	4470128	Cr	MWh		-
	PJM Pool Sales	4470128	Cr		$	-
	PJM Pool Sales	Fuel			$	-
	NER Impact - Net MW					-
	NER Impact - Net Dollars				$	-

Kentucky Power Company

REQUEST

a. Provide Kentucky Power's actual cost to prepare and present Case No. 2011-00401 [9]

b. Provide Kentucky Power's actual cost to date to prepare and present this case in the current proceedings, and going forward, provide monthly updates. This should be considered a recurring data request.

RESPONSE

a & b. Please see table below:

KPSC Case Number	Total Cost to Present	
2011-00401	$855,638.69	
2012-00578	$396,637.74	*

* Total Cost as of January 31, 2013.

WITNESS: Ranie K Wohnhas

[9] Id