COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY)	
FOR APPROVAL OF ITS ENVIRONMENTAL)	
SURCHARGE PLAN, APPROVAL OF ITS AMENDED)	
ENVIORNMENTAL COST RECOVERY)	CASE NO. 2011-00401
SURCHARGE TARIFFS, AND FOR THE GRANT OF)	
CERTIFICATES OF PUBLIC CONVENIENCE AND)	
NECESSITY FOR THE CONSTRUCTION AND)	
ACQUISTION OF RELATED FACILITIES)	

RESPONSES OF KENTUCKY POWER COMPANY TO
KIUCS FIRST SET OF DATA REQUESTS

January 27, 2012

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

STATE OF OHIO)
) CASE NO. 2011-00401
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 25th day of January 2012.

NOTARIAL SEAL STATE OF OHIO

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

Notary Public

My Commission Expires: October 1, 2016

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. 2011-00401

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 16 day of January 2012.

Janet L. White

Notary Public

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

My Commission Expires: ____________

VERIFICATION

The undersigned, Lila P. Munsey, being duly sworn, deposes and says she is the Manager, Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the forgoing responses for which she is the identified witness and that the information contained therein is true and correct to the best of her information, knowledge, and belief

Lila P. Munsey

Lila P. Munsey

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lila P. Munsey, this 20th day of January 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

VERIFICATION

The undersigned, TOBY THOMAS, being duly sworn, deposes and says he is Managing Director, Kentucky Power Generation, Gas, Renewals and Planning 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.

TOBY THOMAS

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Toby Thomas, this the 25th day of January 2012.

Notary Public

My Commission Expires: 1/4/2014

[illegible] J. STEPHENS
[illegible], State of Ohio
[illegible]

VERIFICATION

The undersigned, ROBERT L. WALTON being duly sworn, deposes and says he is Managing Director Projects and Controls 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

ROBERT L. WALTON

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 20 day of January 2012.

Notary Public

My Commission Expires: 5-29-2012

G. MYERS
Notary Public
County
of Ohio

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. 2011-00401
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 24th day of January 2012.

NOTARIAL SEAL STATE OF OHIO

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

Notary Public

My Commission Expires: October 1, 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. 2011-00401
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 20th day of January, 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

Kentucky Power Company

REQUEST

Please provide the per books capital structure of Kentucky Power Company, and American Electric Power Company at December 31, 2010, and March 31, June 30, September 30, 2011, and (as soon as available) December 31, 2011. For the purposes of this data request, please provide the information as follows:

a. Long-term Debt (including that maturing within one year);
b. Short-term Debt;
c. Other Debt (specify);
d. Preferred or Preference Stock;
e. Common Stock;
f. Additional Paid-in Capital;
g. Retained Earnings; and
h. Total Common Equity (total common equity as well as common equity attributable to unregulated operations, if any).

Please provide published balance sheet support for each of the above-requested capital structures, and, if the amounts provided in response to this interrogatory are different from those contained in the published balance sheets, please explain why.

RESPONSE

Kentucky Power objects to the request to the extent it seeks information regarding American Electric Power, Inc. ("AEP.") AEP is not a party to this proceeding, and is not a utility subject to the jurisdiction of the Public Service Commission of Kentucky. AEP is not obligated to assist Kentucky Power in financing the proposed environmental projects in Kentucky Power's 2011 Environmental Compliance Plan. Without waiving this objection, please see exhibits 1-4 and 9-12 of the Company's response to AG 1-31.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

For the same time periods referenced in the preceding interrogatory, please provide the following information for Kentucky Power Company:

a. Embedded cost rates for long-term debt, short-term debt, other debt and preferred or preference stock;

b. Computation of embedded cost rates of long-term debt;

c. Computation of embedded cost rates of short-term debt; and

d. Computation of embedded cost rates of preferred or preference stock.

Note: Schedules should include date of issue, maturity date, dollar amount, coupon rate, net proceeds, annual interest paid and balance of principal, where applicable.

RESPONSE

a. Long-Term Debt (LTD) - 6.484% (LTD structure has not changed over the last year). Short-Term Debt (STD) - Kentucky power did not have STD outstanding between 12/31/2010 - 9/30/2011. Kentucky Power had no preferred or preference stock outstanding during this period.

b. Please see the attached.

c. STD - Kentucky power did not have STD outstanding between 12/31/2010 - 9/30/2011

d. Kentucky Power had no preferred or preference stock outstanding during this period

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY
EFFECTIVE COST OF LONG-TERM DEBT
AS OF September 30, 2011

SERIES	ISSUE DATE	DUE DATE	AVERAGE TERM IN YEARS	PRINCIPAL AMOUNT ISSUED	PREMIUM OR (DISCOUNT) AT ISSUANCE	COMPANY ISSUANCE EXPENSE	NET PROCEEDS	NET PROCEEDS RATIO	EFFECTIVE COST RATE	CURRENT AMOUNT OUTSTANDING	ANNUALIZED COST	WEIGHTED COST RATE
				$	$	$	$	%	%	$	$	%
Global Note												
5.25%	2/5/2004	6/1/2015	11.3	20,000,000	-	-	20,000,000	100.00	5.249	20,000,000	1,049,816	
Subtotal				20,000,000						20,000,000	1,049,816	
Senior Notes												
5.625%	6/13/2003	12/1/2032	29.45	75,000,000	(656,250)	736,575	73,607,175	98.14	5.756	75,000,000	4,317,337	
6.000%	9/11/2007	9/15/2017	10.01	325,000,000	(1,667,250)	2,277,883	321,054,867	98.79	6.164	325,000,000	20,033,514	
7.250%	6/18/2009	6/18/2021	11.99	40,000,000	-	217,919	39,782,081	99.46	7.319	40,000,000	2,927,597	
8.030%	6/18/2009	6/18/2029	19.99	30,000,000	-	163,439	29,836,561	99.46	8.085	30,000,000	2,425,620	
8.130%	6/18/2009	6/18/2039	29.98	60,000,000	-	326,879	59,673,121	99.46	8.179	60,000,000	4,907,388	
Subtotal				530,000,000						530,000,000	34,611,457	
Total				550,000,000								
FMV of mark to market 133 hedge												
TOTAL LONG-TERM DEBT										550,000,000	35,661,273	6.484

Effective Cost Rate = Annualized Cost divided by the Current Amount Outstanding.

Kentucky Power Company

REQUEST

Please provide a consolidating (not consolidated) balance sheet for American Electric Power Company at December 31, 2010, or the most recent date available.

RESPONSE

Kentucky Power objects to the request to the extent it seeks information regarding American Electric Power, Inc. ("AEP") or any of the AEP consolidating companies. AEP and the AEP consolidating companies are not parties to this proceeding, and are not utilities subject to the jurisdiction of the Public Service Commission of Kentucky. AEP and the AEP consolidating companies are not obligated to assist Kentucky Power in financing the proposed environmental projects in Kentucky Power's 2011 Environmental Compliance Plan. Without waiving this objection, Kentucky Power notes the requested information, to the extent it is available, may be found at
http://www.aep.com/investors/financialfilingsandreports/edgar/filings.aspx?section=AEPIncFilings

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a copy of the most recent bond rating agency report (Standard & Poor's, Moody's and Fitch) for Kentucky Power Company and American Electric Power Company.

[Note: Reports provided should be most recent, complete multi-page in-depth report, not a one or two-page update. Also, consider this an on-going data request so that, during the pendency of this proceeding, any new bond rating agency report related to Kentucky Power or AEP will be provided in response to this data request.]

RESPONSE

Kentucky Power objects to the request to the extent it seeks information regarding American Electric Power, Inc. ("AEP.") AEP is not a party to this proceeding, and is not a utility subject to the jurisdiction of the Public Service Commission of Kentucky. AEP is not obligated to assist Kentucky Power in financing the proposed environmental projects in Kentucky Power's 2011 Environmental Compliance Plan. Without waiving this objection, please see the attachments to AG 1-26.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a complete, detailed copies of Kentucky Power Company's most recent bond rating agency presentations (i.e., not a slide-show summary, but the volume that discusses in detail the Company's operations, generation, transmission assets, purchased power contracts (including debt imputation expected from such contracts, financial projections and service territory economics.)

RESPONSE

Please see the attachments to this response. Confidential protection is being sought for Attachments 1 & 2 of this response. Attachment 1 was presented to Moody's, and Attachment 2 was presented to S &P. The forecasts changed slightly in the interim between the two presentations.

WITNESS: Ranie K Wohnhas

American Electric Power
Income Statement
2010 - 2014 Forecast
($000)

			[redacted]		
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kentucky Power					
Revenue					
Retail Revenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Sales to Affiliates	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Operating Revenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Sales					
Total Cost of Sales	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OPERATING EXPENSES					
Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(Gain)/Loss on Sale of Property					
Asset Impairment & Related Charges					
Taxes Other Than Income	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL OPERATING EXPENSES	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Operating Margin/EBITDA	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation & Amortization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Income / (Deductions)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EBIT	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Income Taxes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NET INCOME	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Deductions from Net Income *					
BALANCE FOR COMMON	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Preferred Dividends, Minority Interest, Extraordinary (Income)/Loss

American Electric Power
Cash Flow Statement
2010 - 2014 Forecast
($000)

(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kentucky Power					
OPERATING ACTIVITIES					
Balance For Common	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(Income) Loss from Discontinued Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary Items, Net	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Income from Continuing Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
ADJUSTMENTS TO NET INCOME					
Depreciation & Amortization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Deferred Income Taxes	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
(Gain) / Loss on Sale of Assets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Over/Under Recovery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Pension Contribution	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Change in Other Non-Current Assets and Liabilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cash Flow before Changes in Working Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CHANGES IN WORKING CAPITAL	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CASH FROM OPERATIONS	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
INVESTING ACTIVITIES					
Construction Expenditures	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Proceeds From Sale of Assets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Acquisition of Nuclear Fuel	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Investments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cash used in investing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FINANCING ACTIVITIES					
Common Stock Issued	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Hybrid Equity Issued	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long Term Debt Issued	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Stock Redeemed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Long Term Debt Redeemed	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Short Term Debt Change, Net	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Common Dividends	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Dividends	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capital Lease Proceeds/Lease Principal Payments	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Financing Activities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cash from financing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Change in Cash	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Beginning Cash Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Ending Cash Balance	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

American Electric Power
Balance Sheet
2010 - 2014 Forecast
($000)

			[redacted]		
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kentucky Power					
Plant, Property and Equipment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Construction Work in Process	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation Reserve	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant and Equipment	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other Assets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Assets	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LIABILITIES AND EQUITY					
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Stock					
Hybrid Equity					
Long Term Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CURRENT LIABILITIES					
Short Term Debt			[redacted]	[redacted]	[redacted]
LTD Current					
Other Current Liabilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Current Liabilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Deferred Liabilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital & Liabilities	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

American Electric Power
Financial Ratios
2010 - 2014 Forecast

			[redacted]		
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kentucky Power					
CAPITALIZATION					
Long Term Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Add: A/R Factored	-	-	-	-	-
Add: Capital Leases	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Add: Unfunded Pension Obligation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Less: Securitized Debt					
Less: Spent Nuclear Fuel					
Less: Equity Portion of Hybrid Equity					
Total Long Term Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Short Term Debt			[redacted]	[redacted]	[redacted]
Total Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Stock					
Equity Portion of Hybrid Equity					
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital Incl ST Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Capitalization Ratios					
Short-term Debt			[redacted]	[redacted]	[redacted]
Long-term Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Preferred Stock					
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CREDIT RATIOS					
(As Adjusted for Leases)					
Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
less: Securitization Interest					
plus: Capitalized Interest (AFUDC Debt)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
plus: Other Interest Additions [1]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Adjusted Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cash from Operations	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
less: Changes in Working Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
less: Capitalized Interest (AFUDC Debt)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
plus: Bank of America Settlement Addback					
plus: Pension Contribution in Excess of Expense	[redacted]	[redacted]			
less: Securitization Amortization					
plus: Lease Amortization	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Funds from Operations (FFO)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Funds from Operations Int. Cov.	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
FFO/Total Debt	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Debt/Total Capital	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[1] Includes Adjustment for Interest on Hybrid Equity Issuances and Lease Interest Expense

American Electric Power
Income Statement
2011 - 2014 Forecast
($000)

	[redacted]			
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]
Revenue				
Retail Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Wholesale	[redacted]	[redacted]	[redacted]	[redacted]
Sales to Affiliates	[redacted]	[redacted]	[redacted]	[redacted]
Other Operating Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Total Revenue	[redacted]	[redacted]	[redacted]	[redacted]
Cost of Sales				
Total Cost of Sales	[redacted]	[redacted]	[redacted]	[redacted]
Gross Margin	[redacted]	[redacted]	[redacted]	[redacted]
OPERATING EXPENSES				
Operations & Maintenance	[redacted]	[redacted]	[redacted]	[redacted]
Taxes Other Than Income	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL OPERATING EXPENSES	[redacted]	[redacted]	[redacted]	[redacted]
Operating Margin/EBITDA	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation & Amortization	[redacted]	[redacted]	[redacted]	[redacted]
Other Income / (Deductions)	[redacted]	[redacted]	[redacted]	[redacted]
EBIT	[redacted]	[redacted]	[redacted]	[redacted]
Total Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]
Total Income Taxes	[redacted]	[redacted]	[redacted]	[redacted]
NET INCOME	[redacted]	[redacted]	[redacted]	[redacted]
Deductions from Net Income *				
BALANCE FOR COMMON	[redacted]	[redacted]	[redacted]	[redacted]

* Preferred Dividends, Minority Interest, Extraordinary (Income)/Loss

American Electric Power
Cash Flow Statement
2011 - 2014 Forecast
($000)

	[redacted]			
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]
OPERATING ACTIVITIES				
Balance For Common	[redacted]	[redacted]	[redacted]	[redacted]
(Income) Loss from Discontinued Operations	[redacted]	[redacted]	[redacted]	[redacted]
Extraordinary Items, Net	[redacted]	[redacted]	[redacted]	[redacted]
Net Income from Continuing Operations	[redacted]	[redacted]	[redacted]	[redacted]
ADJUSTMENTS TO NET INCOME				
Depreciation & Amortization	[redacted]	[redacted]	[redacted]	[redacted]
Deferred Income Taxes	[redacted]	[redacted]	[redacted]	[redacted]
Fuel Over/Under Recovery	[redacted]	[redacted]	[redacted]	[redacted]
Pension Contribution	[redacted]	[redacted]	[redacted]	[redacted]
Change in Other Non-Current Assets and Liabilities	[redacted]	[redacted]	[redacted]	[redacted]
Other	[redacted]	[redacted]	[redacted]	[redacted]
Cash Flow before Changes in Working Capital	[redacted]	[redacted]	[redacted]	[redacted]
CHANGES IN WORKING CAPITAL	[redacted]	[redacted]	[redacted]	[redacted]
CASH FROM OPERATIONS	[redacted]	[redacted]	[redacted]	[redacted]
INVESTING ACTIVITIES				
Construction Expenditures	[redacted]	[redacted]	[redacted]	[redacted]
Proceeds From Sale of Assets	[redacted]	[redacted]	[redacted]	[redacted]
Acquisition of Nuclear Fuel	[redacted]	[redacted]	[redacted]	[redacted]
Other Investments	[redacted]	[redacted]	[redacted]	[redacted]
Cash used in investing	[redacted]	[redacted]	[redacted]	[redacted]
FINANCING ACTIVITIES				
Common Stock Issued	[redacted]	[redacted]	[redacted]	[redacted]
Long Term Debt Issued	[redacted]	[redacted]	[redacted]	[redacted]
Short Term Debt Change, Net	[redacted]	[redacted]	[redacted]	[redacted]
Common Dividends	[redacted]	[redacted]	[redacted]	[redacted]
Capital Lease Proceeds/Lease Principal Payments	[redacted]	[redacted]	[redacted]	[redacted]
Cash from financing	[redacted]	[redacted]	[redacted]	[redacted]
Total Change in Cash	[redacted]	[redacted]	[redacted]	[redacted]
Beginning Cash Balance	[redacted]	[redacted]	[redacted]	[redacted]
Ending Cash Balance	[redacted]	[redacted]	[redacted]	[redacted]

American Electric Power
Balance Sheet
2011 - 2014 Forecast
($000)

	[redacted]			
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]
Plant, Property and Equipment	[redacted]	[redacted]	[redacted]	[redacted]
Construction Work in Process	[redacted]	[redacted]	[redacted]	[redacted]
Depreciation Reserve	[redacted]	[redacted]	[redacted]	[redacted]
Net Plant and Equipment	[redacted]	[redacted]	[redacted]	[redacted]
Cash and Equivalents	[redacted]	[redacted]	[redacted]	[redacted]
Other Assets	[redacted]	[redacted]	[redacted]	[redacted]
Total Assets	[redacted]	[redacted]	[redacted]	[redacted]
LIABILITIES AND EQUITY				
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]
Long Term Debt	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital	[redacted]	[redacted]	[redacted]	[redacted]
CURRENT LIABILITIES				
Short Term Debt	[redacted]	[redacted]	[redacted]	[redacted]
LTD Current	[redacted]	[redacted]	[redacted]	[redacted]
Other Current Liabilities	[redacted]	[redacted]	[redacted]	[redacted]
Total Current Liabilities	[redacted]	[redacted]	[redacted]	[redacted]
Deferred Liabilities	[redacted]	[redacted]	[redacted]	[redacted]
Total Capital & Liabilities	[redacted]	[redacted]	[redacted]	[redacted]

American Electric Power
Financial Ratios
2011 - 2014 Forecast

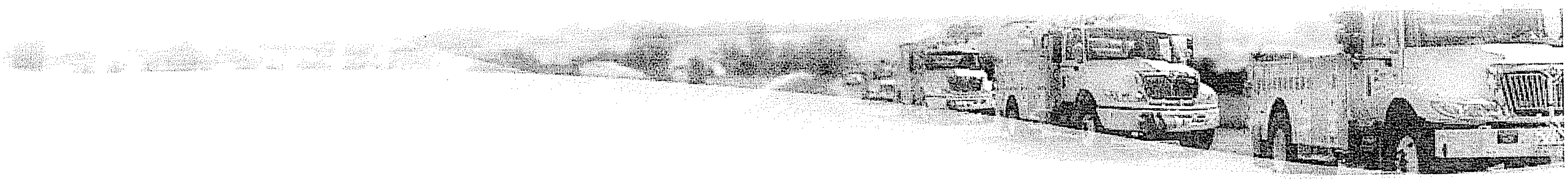
	[redacted]			
(in thousands)	[redacted]	[redacted]	[redacted]	[redacted]
CAPITALIZATION				
Long Term Debt	[redacted]	[redacted]	[redacted]	[redacted]
Add: Operating Leases	[redacted]	[redacted]	[redacted]	[redacted]
Add: Capital Leases	[redacted]	[redacted]	[redacted]	[redacted]
Add: Unfunded Pension Obligation	[redacted]	[redacted]	[redacted]	[redacted]
Total Long Term Debt	[redacted]	[redacted]	[redacted]	[redacted]
Short Term Debt			[redacted]	
Total Debt	[redacted]	[redacted]	[redacted]	[redacted]
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]
Total Capitalization	[redacted]	[redacted]	[redacted]	[redacted]
Capitalization Ratios				
Short-term Debt			[redacted]	
Long-term Debt	[redacted]	[redacted]	[redacted]	[redacted]
Common Equity	[redacted]	[redacted]	[redacted]	[redacted]
CREDIT RATIOS				
(As Adjusted for Leases)				
Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]
plus: Capitalized Interest (AFUDC Debt)	[redacted]	[redacted]	[redacted]	[redacted]
plus: Other Interest Additions [1]	[redacted]	[redacted]	[redacted]	[redacted]
Adjusted Interest Expense	[redacted]	[redacted]	[redacted]	[redacted]
Cash from Operations	[redacted]	[redacted]	[redacted]	[redacted]
less: Changes in Working Capital	[redacted]	[redacted]	[redacted]	[redacted]
less: Capitalized Interest (AFUDC Debt)	[redacted]	[redacted]	[redacted]	[redacted]
plus: Pension Contribution in Excess of Expense	[redacted]	[redacted]	[redacted]	[redacted]
plus: Lease Amortization	[redacted]	[redacted]	[redacted]	[redacted]
Funds from Operations (FFO)	[redacted]	[redacted]	[redacted]	[redacted]
Funds from Operations Int. Cov.	[redacted]	[redacted]	[redacted]	[redacted]
FFO/Total Debt	[redacted]	[redacted]	[redacted]	[redacted]
Total Debt/Total Capital	[redacted]	[redacted]	[redacted]	[redacted]

[1] Includes Adjustment for Interest on Hybrid Equity Issuances and Lease Interest Expense

AEP AMERICAN® ELECTRIC POWER

Moody's Investors Service Handout

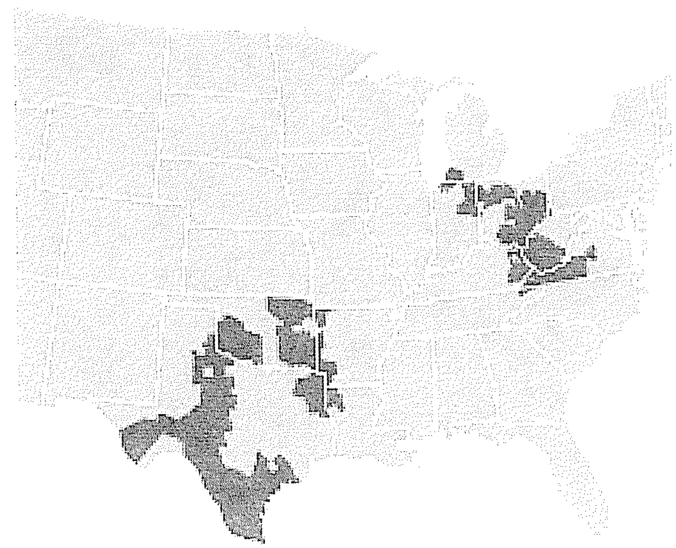
May 4, 2011



American Electric Power

- Regulated Electric Utility
  - Regulatory and economic diversity
  - Operating Company Model
- Focus on Capital Allocation
  - Capital for Growth
  - Return of Capital to Shareholders
  - Pension Funding
- Strong Balance Sheet
  - Stable credit ratings
  - Capital plan supported by cash flow
  - Strong liquidity position
- Growth Opportunities
  - Capital for utility platform
  - Transmission projects
- Dividend yield over 5%

Serving electric customers in 11 states



AEP Fast Facts
5.3 million customers 39 GW of generation capacity 39,000 miles of transmission lines
$17B Market Capitalization BBB/Baa2/BBB credit rating

KPSC Case No. 2011-00401
KIUC First Set of Data Requests
Dated January 13, 2012
Item No. 5
Attachment 3
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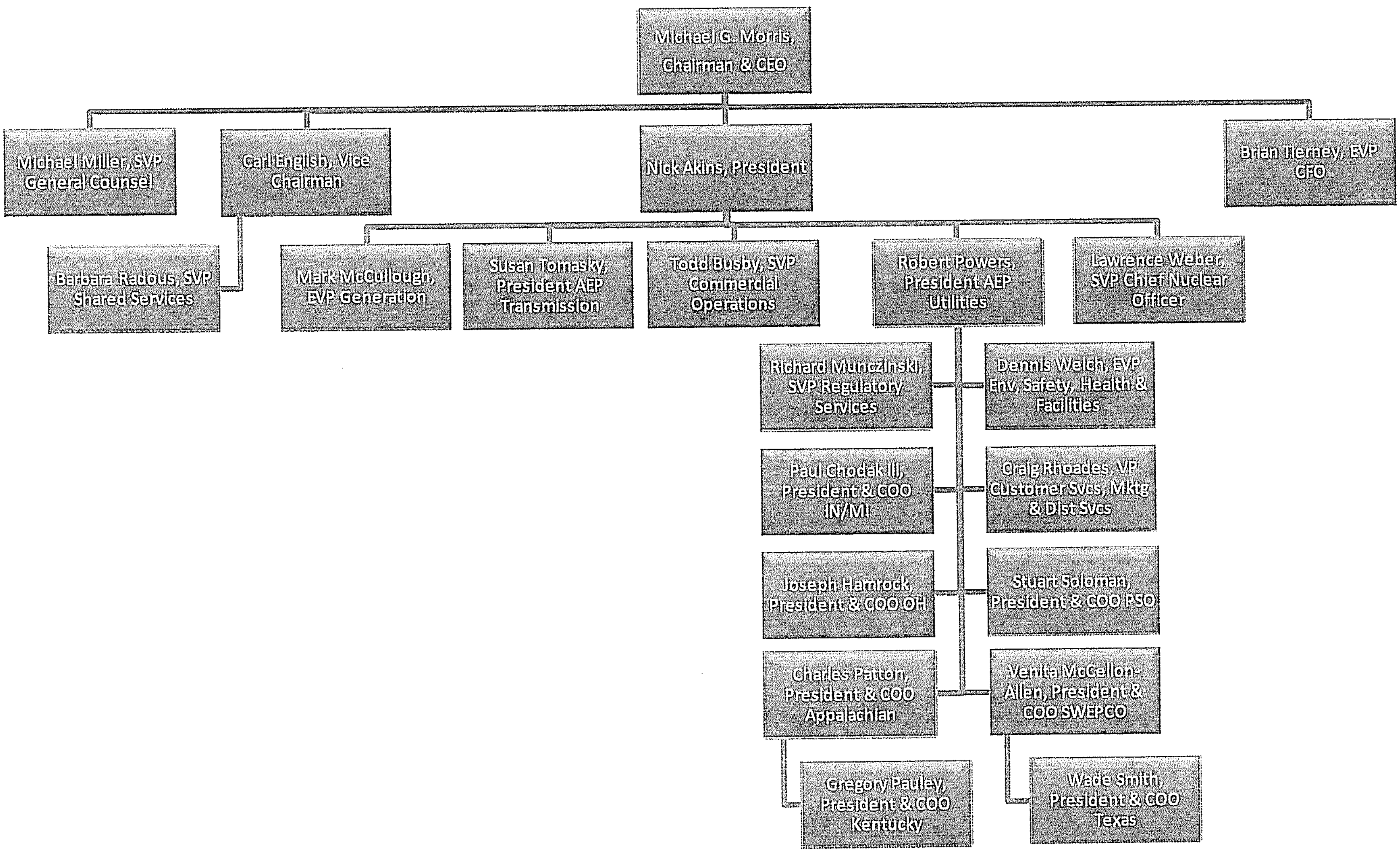
Management Organization Chart



Nick Akins Biography

Nicholas K. Akins

Nick Akins is President of American Electric Power, responsible for AEP's utilities, transmission, generation, commercial operations and OVEC/IKEC organizations.

From 2006 to 2010, Akins was executive vice president - Generation, responsible for all generation activities of AEP's approximately 40,000 MW of generation resources. This includes the engineering, construction, and operations of fossil and hydro generation, nuclear generation, fuels procurement, emission, and logistics, and other resource initiatives such as new generation, environmental retrofits, and carbon capture and storage. Akins was also responsible for the commercial operations, marketing and trading functions for the company.

Previously, he was president and chief operating officer for Southwestern Electric Power Company, serving approximately 439,000 customers in Louisiana, Arkansas and northeast Texas. Named to this position in 2004, he had authority for distribution operations and a wide range of customer and regulatory relationships.

Prior to this, Akins was vice president - energy marketing services, responsible for directing the activities of Market Development, including the transmission marketing and services functions, Energy Delivery External Affairs including community affairs, economic development, advocacy for regulatory and legislative positions within Energy Delivery. Additional responsibilities included the development and implementation of strategies for energy delivery related to AEP's entry into regional transmission organizations.

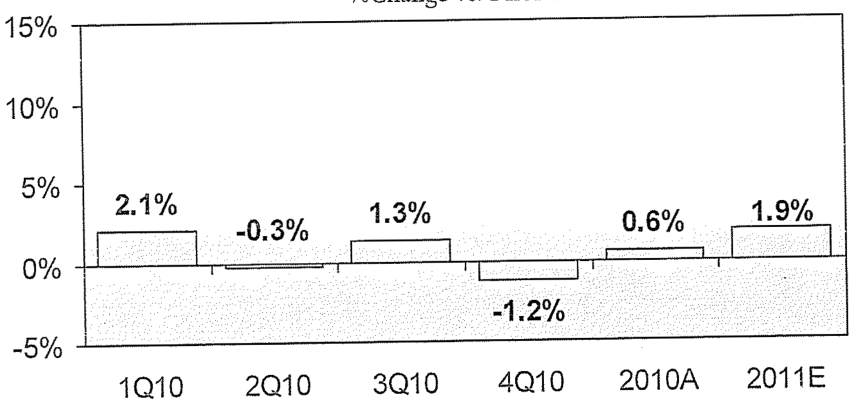
Akins was also vice president - industry restructuring for AEP responsible for enterprise-wide program management for restructuring initiatives in preparation for customer choice in AEP's various jurisdictions.
Previous to Central and South West Corp.'s (CSW) merger with AEP, he served in various director and manager roles within CSW and its operating companies involving mergers and acquisitions, industry restructuring, fuels, system dispatch operations and system planning.

He received a bachelor's degree in 1982 in electrical engineering from Louisiana Tech University in Ruston and a master's degree in electrical engineering in 1986 from Louisiana Tech. He has completed executive management programs at Louisiana State University, the University of Idaho and the Reactor Technology Course for Utility Executives at the Massachusetts Institute of Technology.

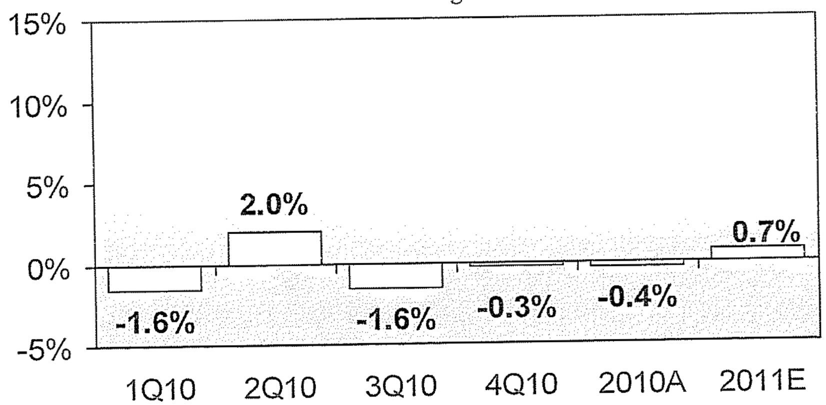
Akins is a registered professional engineer in Texas. He currently serves as the chairman of the Coal Utilization Research Council (CURC), and on the boards of the Electric Power Research Institute (EPRI), the Mid-Ohio Food Bank and the Greater Columbus Arts Council. He also serves on several subsidiary boards of AEP.

Normalized Load Trends

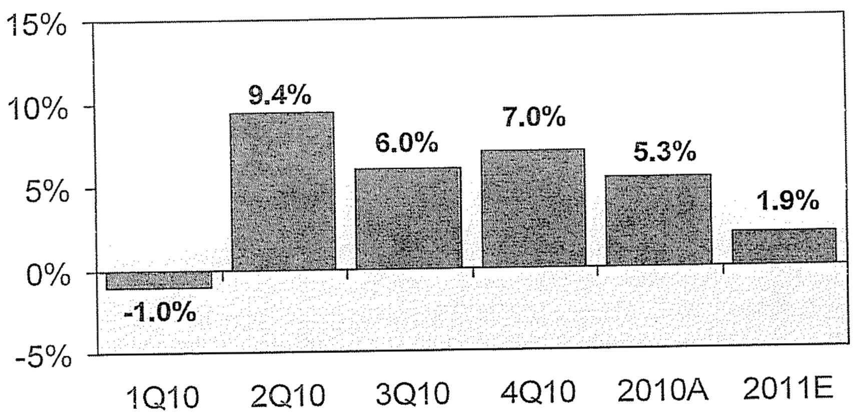
AEP Residential Normalized GWh Sales
%Change vs. Prior Year



AEP Commercial Normalized GWh Sales
%Change vs. Prior Year

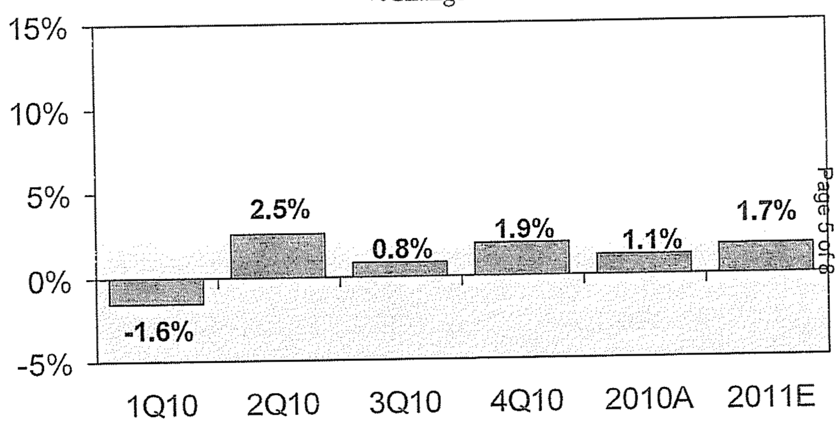


AEP Industrial Normalized GWh Sales
%Change vs. Prior Year



Note: Chart represents connected load

AEP Total Normalized GWh Sales*
%Change vs. Prior Year



*includes firm wholesale load

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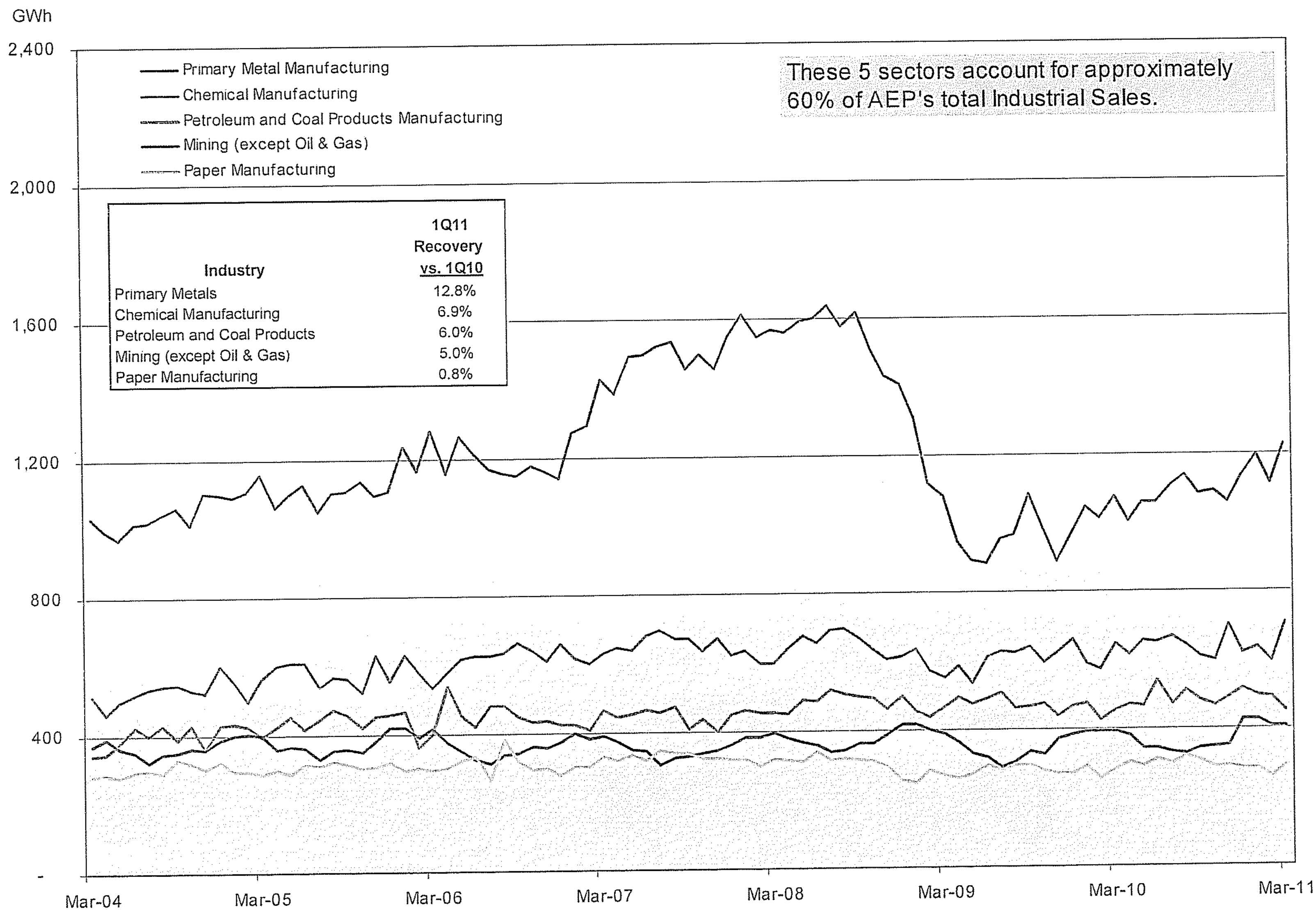
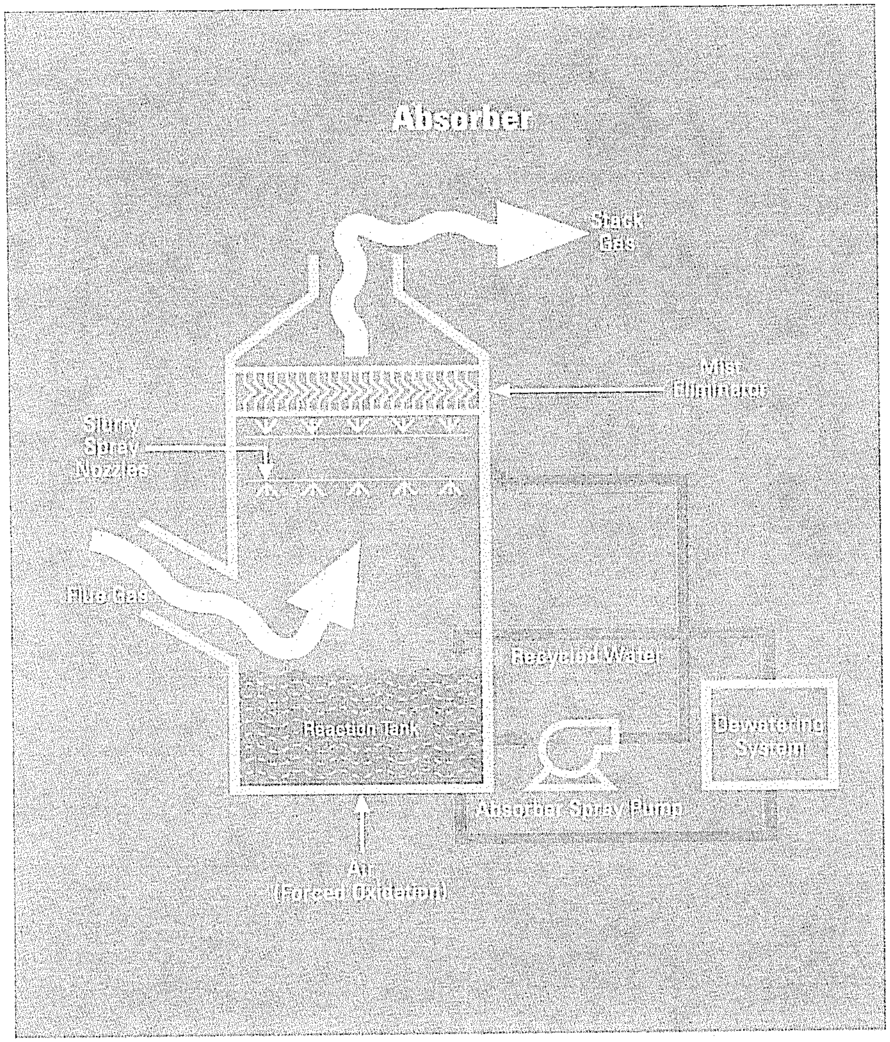
Industrial Sales Volumes

AEP Industrial GWh by Sector



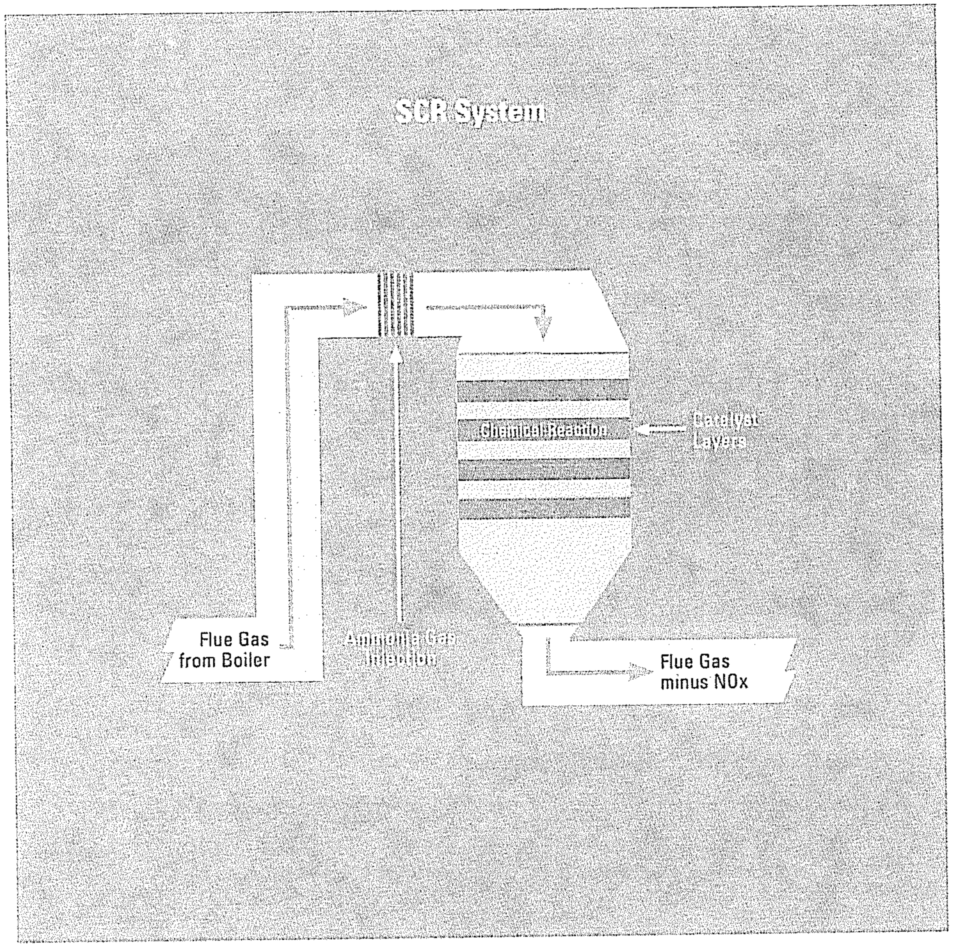
Industry	1Q11 Recovery vs. 1Q10
Primary Metals	12.8%
Chemical Manufacturing	6.9%
Petroleum and Coal Products	6.0%
Mining (except Oil & Gas)	5.0%
Paper Manufacturing	0.8%

How an FGD Works

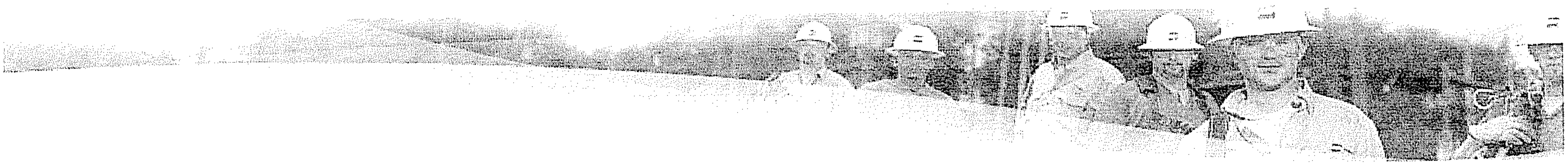


- Limestone is fed from the silo and crushed in the ball mill
- Crushed limestone is mixed with water to form a slurry
- Exhaust gas is routed through absorber vessels where it is sprayed with the slurry
- SO_2 reacts with the slurry and forms calcium sulfate or gypsum
- The calcium sulfate falls to the lower part of the vessel
- Blowers inject air to force oxidation of the product
- Hydroclones wring out much of the water to produce gypsum: the water is re-circulated

How an SCR Works



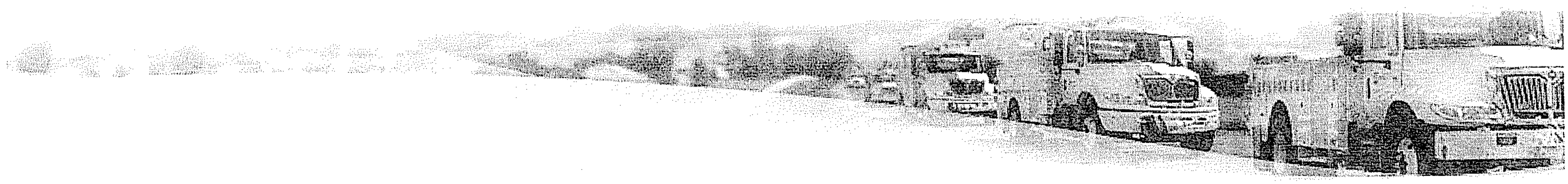
- Urea, a harmless compound often used as fertilizer, is mixed with water
- Steam is used to drive the ammonia gas from the urea mixture
- The ammonia gas is piped into the flue gas ahead of the SCR
- The ammonia reacts with the flue gas as it passes over the catalyst, forming nitrogen gas and water vapor
- The harmless nitrogen and water vapor are released into the atmosphere



AEP AMERICAN® ELECTRIC POWER

Standard & Poor's Meeting Handout

September 29, 2011



Management Participants

Nick Akins, AEP President

Brian Tierney, EVP & CFO

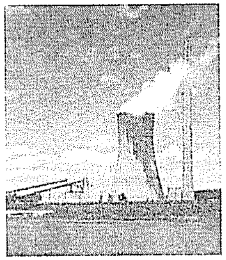
Joe Hamrock, President & COO, AEP Ohio

Rich Munczinski, SVP Regulatory Services

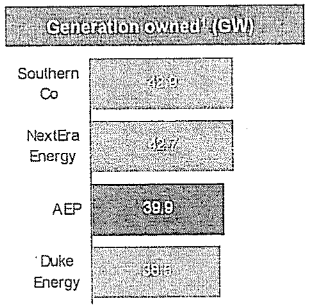
Chuck Zebula, Treasurer & SVP Investor Relations

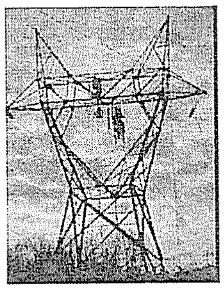
Renee Hawkins, Asst. Treasurer & MD Corporate Finance

American Electric Power

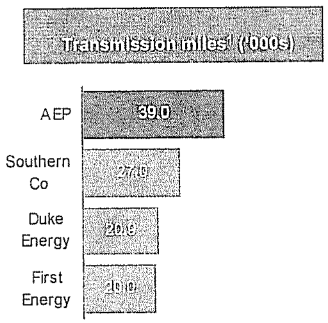


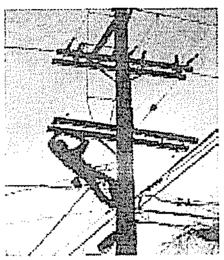
One of the largest
U.S. electricity generators



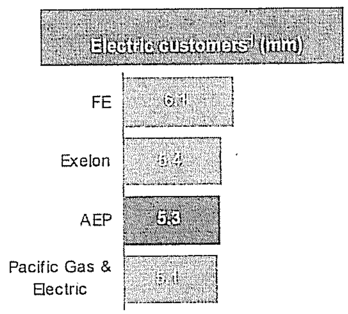


The largest U.S. electricity
transmitter





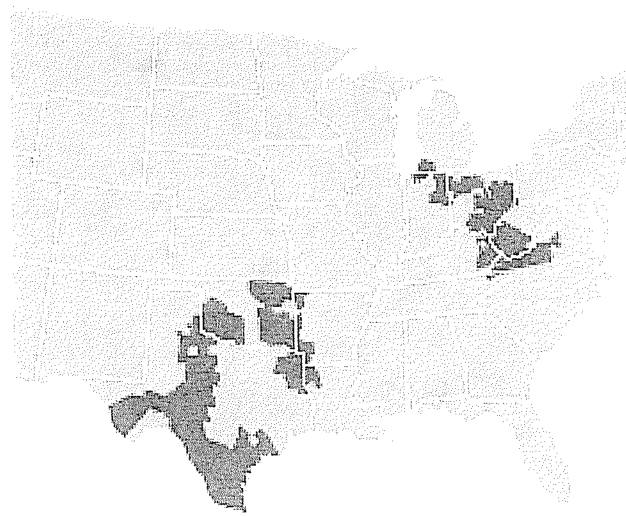
One of the largest U.S.
electricity distributors



[1] Company Filings

Strictly Confidential

Serving electric customers in 11 states



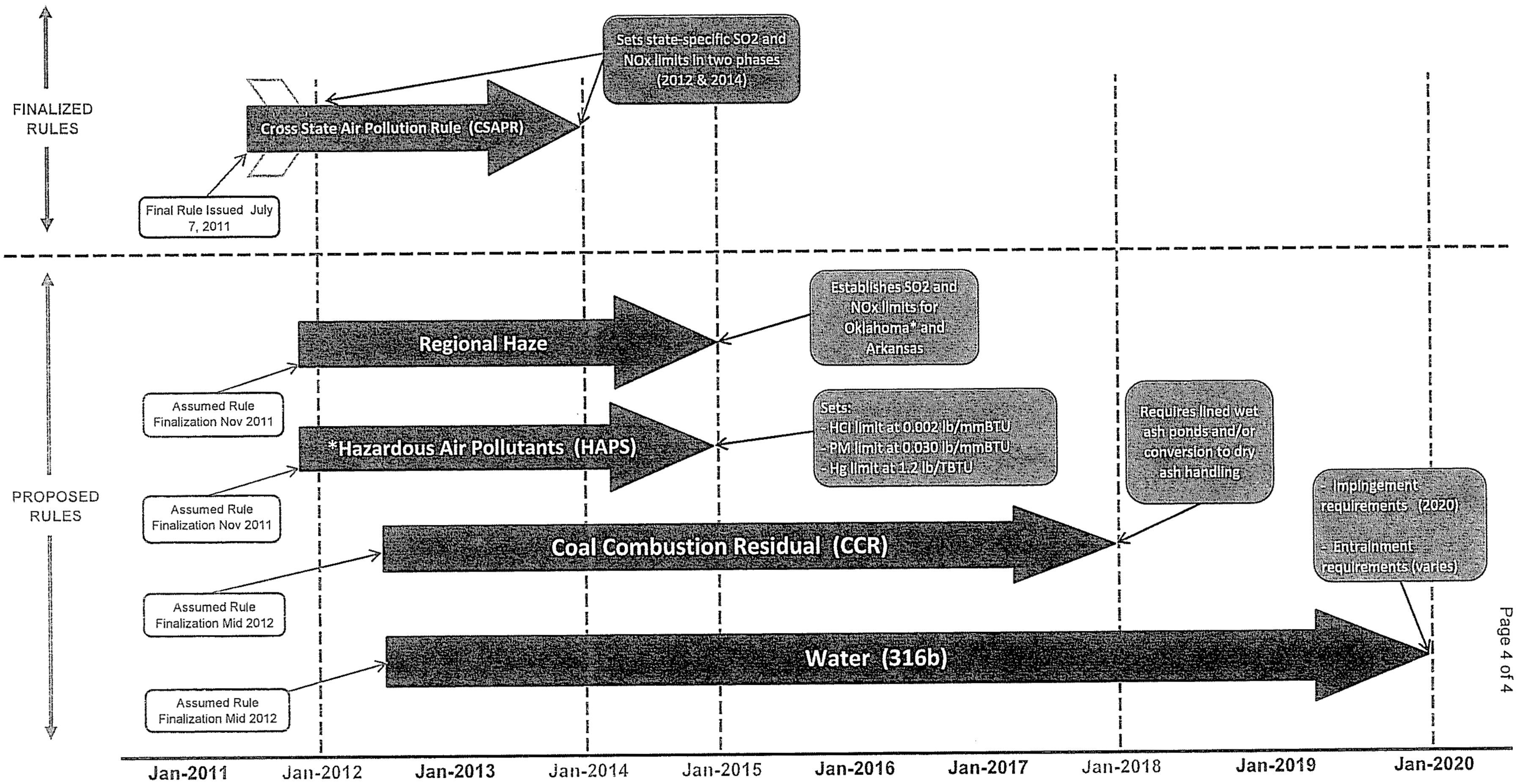
AEP Fast Facts

$14.4B Revenues *
$1.2B Net Income *
10.75% System ROE *

$17.9B Market Capitalization
BBB/Baa2/BBB credit rating

* - represents results for 2010

EPA Regulatory Deadlines



* Units that will be retrofit may be eligible for a one year compliance extension from the EPA related to HAPs and the Oklahoma units may also be eligible for a one year compliance extension under Regional Haze.

KPSC Case No. 2011-00401
KIUC First Set of Data Requests
Dated January 13, 2012
Item No. 5
Attachment 4
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Strictly Confidential

Kentucky Power Company

REQUEST

a. Please provide the monthly short-term debt balances for Kentucky Power Company for each month from January 2009 through the most recent month available. Please explain how the monthly short-term debt balance was determined (e.g., month-ending balance, average daily balance) and provide a sample calculation.

b. Please provide for each month, the monthly cost-rate of that short-term debt, as well as a sample calculation showing how that monthly cost rate is derived.

c. Please provide a narrative description of the short-term debt financing arrangements for the Company. If there is an inter-corporate money-pooling arrangement, please provide a narrative description of that arrangement.

RESPONSE

a. Please see Attachment 1. Short-term debt (STD) month end is the amount of STD outstanding on the last day of each month.

b. Please see Attachment 1. The monthly rate is an average daily rate of STD for the month.

c. The AEP System uses a corporate borrowing program that is funded by any excess cash available at AEP utility subsidiaries, as well as the issuance of commercial paper, and is backed by bank lines of credit to meet short-term borrowing needs. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries (including KYPCo) with short-term borrowings. The AEP System Corporate Borrowing Program (CBP) operates in accordance with the terms and conditions outlined by the Securities and Exchange Commission (SEC) and adopted by the Federal Energy Regulatory Commission (FERC).

Excel format of this attachment is also available on the enclosed CD.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Schedule of Short Term Debt
Thirty Six Months ended December 31, 2011

Line No. (1)	Month (2)	Year (3)	Notes Payable Outstanding at the End of the Month (4)	Monthly Cost
1	January	2009	151,601,832	1.94%
2	February	2009	146,762,000	1.78%
3	March	2009	157,289,699	1.39%
4	April	2009	156,177,865	1.19%
5	May	2009	168,665,181	0.95%
6	June	2009	6,049,931	0.71%
7	July	2009	0	
8	August	2009	0	
9	September	2009	0	
10	October	2009	0	
11	November	2009	0	
12	December	2009	485,337	0.21%
13	January	2010	805,286	0.16%
14	February	2010	2,984,116	0.19%
15	March	2010	0	
16	April	2010	0	
17	May	2010	6,714,455	0.25%
18	June	2010	4,268,088	0.41%
19	July	2010	0	
20	August	2010	0	
21	September	2010	0	
22	October	2010	0	
23	November	2010	0	
24	December	2010	0	
25	January	2011	0	
26	February	2011	0	
27	March	2011	0	

Line No. (1)	Month (2)	Year (3)	Notes Payable Outstanding at the End of the Month (4)	Monthly Cost
28	April	2011	0	
29	May	2011	0	
30	June	2011	0	
31	July	2011	0	
32	August	2011	0	
33	September	2011	0	
34	October	2011	0	
35	November	2011	0	
36	December	2011	0	

Kentucky Power Company
Short Term Debt Balance and Cost Calculation
Thirty Six Months ended December 31, 2011

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	1/1/2009	(131,406,959.93)		2.28%	0.011078%	
	1/2/2009	(132,337,908.20)		2.28%	0.011156%	
	1/3/2009	(132,346,272.66)		2.28%	0.011157%	
	1/4/2009	(132,354,637.65)		2.28%	0.011157%	
	1/5/2009	(135,901,041.26)		2.28%	0.011456%	
	1/6/2009	(131,976,024.59)		2.25%	0.011001%	
	1/7/2009	(135,415,521.92)		2.26%	0.011343%	
	1/8/2009	(130,781,085.13)		2.26%	0.010955%	
	1/9/2009	(139,498,245.24)		2.26%	0.011685%	
	1/10/2009	(139,507,006.46)		2.26%	0.011686%	
	1/11/2009	(139,515,768.24)		2.26%	0.011687%	
	1/12/2009	(140,222,271.56)		1.73%	0.009004%	
	1/13/2009	(137,053,409.21)		1.75%	0.008885%	
	1/14/2009	(135,209,910.65)		1.74%	0.008740%	
	1/15/2009	(132,713,733.06)		1.76%	0.008652%	
	1/16/2009	(132,623,253.61)		1.76%	0.008646%	
	1/17/2009	(132,629,736.08)		1.76%	0.008646%	
	1/18/2009	(132,636,218.87)		1.76%	0.008647%	
	1/19/2009	(132,642,701.98)		1.76%	0.008647%	
	1/20/2009	(128,338,651.44)		1.76%	0.008367%	
	1/21/2009	(131,912,848.85)		1.76%	0.008600%	
	1/22/2009	(134,201,407.12)		1.76%	0.008749%	
	1/23/2009	(132,889,893.31)		1.76%	0.008663%	
	1/24/2009	(132,896,388.82)		1.76%	0.008664%	
	1/25/2009	(132,902,884.65)		1.76%	0.008664%	
	1/26/2009	(150,341,105.92)		1.76%	0.009801%	
	1/27/2009	(149,755,575.82)		1.76%	0.009763%	
	1/28/2009	(150,334,596.37)		1.76%	0.009801%	
	1/29/2009	(149,010,851.60)		1.76%	0.009714%	
Friday	**1/30/2009**	(151,601,831.51)		1.76%	0.009883%	
	1/31/2009	(151,609,241.63)		1.76%	0.009884%	1.94%
	2/1/2009	(151,616,652.12)		1.76%	0.009884%	
	2/2/2009	(152,021,886.13)		1.76%	0.009911%	
	2/3/2009	(149,060,547.52)		1.76%	0.009718%	
	2/4/2009	(153,886,901.91)		1.76%	0.010032%	
	2/5/2009	(144,703,595.79)		1.76%	0.009434%	
	2/6/2009	(143,573,600.13)		1.76%	0.009360%	
	2/7/2009	(143,580,617.85)		1.76%	0.009360%	
	2/8/2009	(143,587,635.92)		1.76%	0.009361%	
	2/9/2009	(152,564,717.02)		1.76%	0.009946%	
	2/10/2009	(150,532,245.41)		1.76%	0.009814%	
	2/11/2009	(147,834,250.21)		1.76%	0.009638%	
	2/12/2009	(146,017,867.53)		1.82%	0.009841%	
	2/13/2009	(146,832,341.69)		1.81%	0.009853%	
	2/14/2009	(146,839,729.08)		1.81%	0.009853%	
	2/15/2009	(146,847,116.85)		1.81%	0.009854%	
	2/16/2009	(146,854,504.99)		1.81%	0.009854%	
	2/17/2009	(137,904,424.36)		1.80%	0.009186%	
	2/18/2009	(135,978,652.59)		1.79%	0.009036%	
	2/19/2009	(142,157,047.88)		1.79%	0.009447%	
	2/20/2009	(143,676,146.23)		1.79%	0.009547%	
	2/21/2009	(143,683,304.60)		1.79%	0.009548%	
	2/22/2009	(143,690,463.32)		1.79%	0.009548%	
	2/23/2009	(143,551,525.77)		1.79%	0.009535%	
	2/24/2009	(141,402,899.52)		1.79%	0.009392%	
	2/25/2009	(140,949,548.19)		1.79%	0.009362%	
	2/26/2009	(149,860,995.06)		1.74%	0.009672%	
Friday	**2/27/2009**	(146,761,999.69)		1.74%	0.009472%	
	2/28/2009	(146,769,101.27)		1.74%	0.009472%	1.78%
	3/1/2009	(146,776,203.20)		1.74%	0.009473%	
	3/2/2009	(148,121,620.13)		1.74%	0.009559%	
	3/3/2009	(145,948,308.91)		1.74%	0.009419%	
	3/4/2009	(146,756,869.38)		1.74%	0.009471%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	3/5/2009	(139,428,005.40)		1.74%	0.008998%	
	3/6/2009	(144,865,798.53)		1.74%	0.009349%	
	3/7/2009	(144,872,808.36)		1.74%	0.009350%	
	3/8/2009	(144,879,818.53)		1.74%	0.009350%	
	3/9/2009	(152,066,241.52)		1.56%	0.008789%	
	3/10/2009	(150,088,899.22)		1.56%	0.008675%	
	3/11/2009	(147,210,884.34)		1.57%	0.008573%	
	3/12/2009	(148,225,347.16)		1.22%	0.006724%	
	3/13/2009	(144,017,608.36)		1.22%	0.006533%	
	3/14/2009	(144,022,506.92)		1.22%	0.006534%	
	3/15/2009	(144,027,405.65)		1.22%	0.006534%	
	3/16/2009	(152,380,086.75)		1.22%	0.006894%	
	3/17/2009	(150,998,815.12)		1.22%	0.006824%	
	3/18/2009	(150,899,116.37)		1.22%	0.006820%	
	3/19/2009	(155,598,006.06)		1.22%	0.007025%	
	3/20/2009	(161,451,788.47)		1.22%	0.007290%	
	3/21/2009	(161,457,254.28)		1.22%	0.007290%	
	3/22/2009	(161,462,720.27)		1.22%	0.007291%	
	3/23/2009	(161,838,246.04)		1.22%	0.007307%	
	3/24/2009	(159,869,014.50)		1.22%	0.007206%	
	3/25/2009	(160,035,218.80)		1.22%	0.007214%	
	3/26/2009	(161,307,621.43)		1.22%	0.007310%	
	3/27/2009	(161,153,385.81)		1.22%	0.007303%	
	3/28/2009	(161,158,861.63)		1.22%	0.007304%	
	3/29/2009	(161,164,337.63)		1.22%	0.007304%	
	3/30/2009	(159,705,369.22)		1.22%	0.007238%	
Tuesday	**3/31/2009**	(157,289,698.89)		1.22%	0.007128%	1.39%
	4/1/2009	(156,909,006.71)		1.22%	0.007111%	
	4/2/2009	(158,842,299.25)		1.22%	0.007152%	
	4/3/2009	(166,061,611.08)		1.22%	0.007477%	
	4/4/2009	(166,067,217.07)		1.22%	0.007477%	
	4/5/2009	(166,072,823.25)		1.22%	0.007477%	
	4/6/2009	(164,405,166.23)		1.22%	0.007402%	
	4/7/2009	(170,236,158.20)		1.22%	0.007665%	
	4/8/2009	(169,341,851.07)		1.22%	0.007625%	
	4/9/2009	(166,870,361.70)		1.22%	0.007513%	
	4/10/2009	(167,537,844.39)		1.22%	0.007543%	
	4/11/2009	(167,543,500.21)		1.22%	0.007544%	
	4/12/2009	(167,549,156.23)		1.22%	0.007544%	
	4/13/2009	(165,965,115.40)		1.22%	0.007473%	
	4/14/2009	(158,037,505.72)		1.16%	0.006805%	
	4/15/2009	(156,048,649.93)		1.16%	0.006719%	
	4/16/2009	(160,909,910.84)		1.16%	0.006929%	
	4/17/2009	(159,042,781.53)		1.16%	0.006848%	
	4/18/2009	(159,047,916.11)		1.16%	0.006848%	
	4/19/2009	(159,053,050.86)		1.16%	0.006849%	
	4/20/2009	(158,027,601.36)		1.16%	0.006805%	
	4/21/2009	(152,470,302.01)		1.16%	0.006565%	
	4/22/2009	(158,770,853.26)		1.16%	0.006837%	
	4/23/2009	(160,199,961.09)		1.16%	0.006898%	
	4/24/2009	(160,685,612.57)		1.16%	0.006919%	
	4/25/2009	(160,690,800.20)		1.16%	0.006919%	
	4/26/2009	(160,695,987.99)		1.16%	0.006919%	
	4/27/2009	(161,170,349.63)		1.21%	0.007212%	
	4/28/2009	(159,695,292.31)		1.21%	0.007146%	
	4/29/2009	(158,870,576.82)		1.21%	0.007109%	
Thursday	**4/30/2009**	(156,177,864.54)		1.21%	0.006988%	1.19%
	5/1/2009	(155,984,273.05)		1.21%	0.006980%	
	5/2/2009	(155,989,506.24)		1.21%	0.006980%	
	5/3/2009	(155,994,739.60)		1.21%	0.006980%	
	5/4/2009	(157,192,293.41)		1.21%	0.007034%	
	5/5/2009	(156,890,929.77)		1.21%	0.007020%	
	5/6/2009	(157,429,225.18)		1.21%	0.007044%	
	5/7/2009	(152,178,468.84)		1.21%	0.006809%	
	5/8/2009	(162,118,161.66)		1.21%	0.007254%	
	5/9/2009	(162,123,600.63)		1.21%	0.007254%	
	5/10/2009	(162,129,039.78)		1.21%	0.007255%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	5/11/2009	(160,547,553.48)		1.21%	0.007184%	
	5/12/2009	(158,800,954.65)		0.92%	0.005405%	
	5/13/2009	(157,525,213.22)		0.92%	0.005362%	
	5/14/2009	(158,593,159.72)		0.83%	0.004847%	
	5/15/2009	(159,811,435.33)		0.83%	0.004885%	
	5/16/2009	(159,815,097.67)		0.83%	0.004885%	
	5/17/2009	(159,818,760.10)		0.83%	0.004885%	
	5/18/2009	(157,281,849.90)		0.83%	0.004807%	
	5/19/2009	(154,505,031.35)		0.83%	0.004722%	
	5/20/2009	(150,315,503.17)		0.83%	0.004594%	
	5/21/2009	(159,564,334.43)		0.83%	0.004877%	
	5/22/2009	(160,576,859.47)		0.80%	0.004759%	
	5/23/2009	(160,580,427.24)		0.80%	0.004759%	
	5/24/2009	(160,583,995.10)		0.80%	0.004759%	
	5/25/2009	(160,587,563.04)		0.80%	0.004759%	
	5/26/2009	(159,772,212.25)		0.76%	0.004472%	
	5/27/2009	(165,632,260.62)		0.76%	0.004655%	
	5/28/2009	(167,238,928.87)		0.76%	0.004730%	
Friday	**5/29/2009**	(168,665,181.33)		0.77%	0.004797%	
	5/30/2009	(168,668,778.19)		0.77%	0.004797%	
	5/31/2009	(168,672,375.13)		0.77%	0.004798%	0.95%
	6/1/2009	(170,855,376.38)		0.74%	0.004655%	
	6/2/2009	(169,394,397.39)		0.74%	0.004615%	
	6/3/2009	(170,601,883.64)		0.71%	0.004503%	
	6/4/2009	(164,113,400.87)		0.72%	0.004350%	
	6/5/2009	(163,560,314.02)		0.71%	0.004326%	
	6/6/2009	(163,563,557.61)		0.71%	0.004326%	
	6/7/2009	(163,566,801.26)		0.71%	0.004326%	
	6/8/2009	(174,108,041.92)		0.70%	0.004524%	
	6/9/2009	(172,153,241.34)		0.71%	0.004534%	
	6/10/2009	(170,174,541.58)		0.71%	0.004464%	
	6/11/2009	(169,067,023.14)		0.70%	0.004409%	
	6/12/2009	(167,911,054.47)		0.71%	0.004410%	
	6/13/2009	(167,914,361.01)		0.71%	0.004410%	
	6/14/2009	(167,917,667.61)		0.71%	0.004410%	
	6/15/2009	(166,905,836.38)		0.66%	0.004081%	
	6/16/2009	(166,894,057.18)		0.65%	0.004022%	
	6/17/2009	(160,317,012.73)		0.65%	0.003877%	
	6/18/2009	(35,268,928.72)		0.68%	0.000888%	
	6/19/2009	(35,149,583.35)		0.69%	0.000896%	
	6/20/2009	(35,358,038.04)		0.69%	0.000902%	
	6/21/2009	(35,358,714.05)		0.69%	0.000902%	
	6/22/2009	(31,529,878.11)		0.70%	0.000823%	
	6/23/2009	(35,257,272.96)		0.70%	0.000918%	
	6/24/2009	(34,480,625.60)		0.71%	0.000912%	
	6/25/2009	(6,123,350.60)		0.72%	0.000163%	
	6/26/2009	(6,467,090.36)		0.72%	0.000173%	
	6/27/2009	(6,467,219.85)		0.72%	0.000173%	
	6/28/2009	(6,467,349.34)		0.72%	0.000173%	
	6/29/2009	(5,948,156.76)		0.72%	0.000159%	
Tuesday	**6/30/2009**	(6,049,931.46)		0.72%	0.000162%	0.71%
	7/1/2009	(5,929,044.05)		0.72%	0.000158%	
	7/2/2009	(5,659,741.28)		0.70%	0.000146%	
	7/3/2009	(5,802,435.33)		0.70%	0.000150%	
	7/4/2009	(5,802,547.74)		0.70%	0.000150%	
	7/5/2009	(5,802,660.15)		0.70%	0.000150%	
	7/6/2009	(7,504,296.51)		0.70%	0.000194%	
	7/7/2009	(5,301,210.47)		0.70%	0.000137%	
	7/8/2009	(8,141,841.22)		0.70%	0.000211%	
	7/9/2009	(9,740,706.42)		0.71%	0.000254%	
	7/10/2009	(7,643,029.75)		0.71%	0.000201%	
	7/11/2009	(7,643,180.37)		0.71%	0.000201%	
	7/12/2009	(7,643,331.00)		0.71%	0.000201%	
	7/13/2009	(6,389,928.06)		0.71%	0.000168%	
	7/14/2009	(477,708.13)		0.72%	0.000013%	
	7/15/2009				0.000000%	
	7/16/2009	(1,580,038.90)		0.64%	0.000037%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	7/17/2009	(844,103.60)		0.63%	0.000020%	
	7/18/2009	(844,118.40)		0.63%	0.000020%	
	7/19/2009	(844,133.20)		0.63%	0.000020%	
	7/20/2009	(5,216,279.15)		0.62%	0.000120%	
	7/21/2009				0.000000%	
	7/22/2009				0.000000%	
	7/23/2009	(514,732.02)		0.63%	0.000012%	
	7/24/2009	(2,995,268.22)		0.62%	0.000069%	
	7/25/2009	(2,995,320.12)		0.62%	0.000069%	
	7/26/2009	(2,995,372.02)		0.62%	0.000069%	
	7/27/2009	(4,626,757.56)		0.60%	0.000102%	
	7/28/2009	(4,501,719.24)		0.61%	0.000102%	
	7/29/2009	(2,107,619.43)		0.61%	0.000048%	
	7/30/2009				0.000000%	
Friday	**7/31/2009**				0.000000%	0.67%
	8/1/2009				0.000000%	
	8/2/2009				0.000000%	
	8/3/2009				0.000000%	
	8/4/2009				0.000000%	
	8/5/2009				0.000000%	
	8/6/2009				0.000000%	
	8/7/2009				0.000000%	
	8/8/2009				0.000000%	
	8/9/2009				0.000000%	
	8/10/2009	(4,035,990.53)		0.62%	0.000093%	
	8/11/2009	(2,093,013.12)		0.62%	0.000048%	
	8/12/2009	(926,592.74)		0.62%	0.000021%	
	8/13/2009				0.000000%	
	8/14/2009				0.000000%	
	8/15/2009				0.000000%	
	8/16/2009				0.000000%	
	8/17/2009				0.000000%	
	8/18/2009				0.000000%	
	8/19/2009				0.000000%	
	8/20/2009				0.000000%	
	8/21/2009				0.000000%	
	8/22/2009				0.000000%	
	8/23/2009				0.000000%	
	8/24/2009				0.000000%	
	8/25/2009				0.000000%	
	8/26/2009				0.000000%	
	8/27/2009				0.000000%	
	8/28/2009				0.000000%	
	8/29/2009				0.000000%	
	8/30/2009				0.000000%	
Monday	**8/31/2009**				0.000000%	0.62%
	9/1/2009				0.000000%	
	9/2/2009				0.000000%	
	9/3/2009				0.000000%	
	9/4/2009				0.000000%	
	9/5/2009				0.000000%	
	9/6/2009				0.000000%	
	9/7/2009				0.000000%	
	9/8/2009				0.000000%	
	9/9/2009				0.000000%	
	9/10/2009				0.000000%	
	9/11/2009				0.000000%	
	9/12/2009				0.000000%	
	9/13/2009				0.000000%	
	9/14/2009				0.000000%	
	9/15/2009				0.000000%	
	9/16/2009				0.000000%	
	9/17/2009				0.000000%	
	9/18/2009				0.000000%	
	9/19/2009				0.000000%	
	9/20/2009				0.000000%	
	9/21/2009				0.000000%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	9/22/2009				0.000000%	
	9/23/2009				0.000000%	
	9/24/2009	(1,436,766.12)		0.27%	0.000014%	
	9/25/2009	(2,091,727.48)		0.31%	0.000024%	
	9/26/2009	(2,091,745.27)		0.31%	0.000024%	
	9/27/2009	(2,091,763.05)		0.31%	0.000024%	
	9/28/2009				0.000000%	
	9/29/2009				0.000000%	
Wednesday	**9/30/2009**				0.000000%	0.30%
	10/1/2009				0.000000%	
	10/2/2009				0.000000%	
	10/3/2009				0.000000%	
	10/4/2009				0.000000%	
	10/5/2009	(1,477,483.62)		0.28%	0.000015%	
	10/6/2009				0.000000%	
	10/7/2009	(7,081,693.65)		0.25%	0.000065%	
	10/8/2009				0.000000%	
	10/9/2009				0.000000%	
	10/10/2009				0.000000%	
	10/11/2009				0.000000%	
	10/12/2009				0.000000%	
	10/13/2009				0.000000%	
	10/14/2009				0.000000%	
	10/15/2009				0.000000%	
	10/16/2009				0.000000%	
	10/17/2009				0.000000%	
	10/18/2009				0.000000%	
	10/19/2009				0.000000%	
	10/20/2009				0.000000%	
	10/21/2009				0.000000%	
	10/22/2009				0.000000%	
	10/23/2009				0.000000%	
	10/24/2009				0.000000%	
	10/25/2009				0.000000%	
	10/26/2009				0.000000%	
	10/27/2009				0.000000%	
	10/28/2009				0.000000%	
	10/29/2009				0.000000%	
Friday	**10/30/2009**				0.000000%	0.26%
	10/31/2009				0.000000%	
	11/1/2009				0.000000%	
	11/2/2009				0.000000%	
	11/3/2009				0.000000%	
	11/4/2009				0.000000%	
	11/5/2009				0.000000%	
	11/6/2009				0.000000%	
	11/7/2009				0.000000%	
	11/8/2009				0.000000%	
	11/9/2009				0.000000%	
	11/10/2009				0.000000%	
	11/11/2009				0.000000%	
	11/12/2009				0.000000%	
	11/13/2009				0.000000%	
	11/14/2009				0.000000%	
	11/15/2009				0.000000%	
	11/16/2009				0.000000%	
	11/17/2009				0.000000%	
	11/18/2009				0.000000%	
	11/19/2009				0.000000%	
	11/20/2009	(1,228,065.87)		0.20%	0.000009%	
	11/21/2009	(1,228,072.74)		0.20%	0.000009%	
	11/22/2009	(1,228,079.60)		0.20%	0.000009%	
	11/23/2009				0.000000%	
	11/24/2009				0.000000%	
	11/25/2009				0.000000%	
	11/26/2009				0.000000%	
	11/27/2009				0.000000%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	11/28/2009				0.000000%	
	11/29/2009				0.000000%	
Monday	**11/30/2009**				0.000000%	0.20%
	12/1/2009				0.000000%	
	12/2/2009				0.000000%	
	12/3/2009				0.000000%	
	12/4/2009				0.000000%	
	12/5/2009				0.000000%	
	12/6/2009				0.000000%	
	12/7/2009				0.000000%	
	12/8/2009				0.000000%	
	12/9/2009				0.000000%	
	12/10/2009				0.000000%	
	12/11/2009				0.000000%	
	12/12/2009				0.000000%	
	12/13/2009				0.000000%	
	12/14/2009				0.000000%	
	12/15/2009				0.000000%	
	12/16/2009				0.000000%	
	12/17/2009				0.000000%	
	12/18/2009	(1,771,470.22)		0.18%	0.000012%	
	12/19/2009	(1,771,479.22)		0.18%	0.000012%	
	12/20/2009	(1,771,488.22)		0.18%	0.000012%	
	12/21/2009	(1,159,134.70)		0.21%	0.000009%	
	12/22/2009	(250,061.40)		0.21%	0.000002%	
	12/23/2009	(1,367,337.73)		0.21%	0.000011%	
	12/24/2009	(2,190,054.42)		0.22%	0.000018%	
	12/25/2009	(2,190,067.68)		0.22%	0.000018%	
	12/26/2009	(2,190,080.94)		0.22%	0.000018%	
	12/27/2009	(2,190,094.20)		0.22%	0.000018%	
	12/28/2009				0.000000%	
	12/29/2009				0.000000%	
	12/30/2009				0.000000%	
Thursday	**12/31/2009**	(485,336.84)		0.21%	0.000004%	0.21%
	1/1/2010	(485,339.69)		0.21%	0.000004%	
	1/2/2010	(485,342.55)		0.21%	0.000004%	
	1/3/2010	(485,345.40)		0.21%	0.000004%	
	1/4/2010	(497,293.18)		0.18%	0.000003%	
	1/5/2010	(3,077,420.39)		0.19%	0.000022%	
	1/6/2010	(5,361,441.55)		0.16%	0.000032%	
	1/7/2010				0.000000%	
	1/8/2010				0.000000%	
	1/9/2010				0.000000%	
	1/10/2010				0.000000%	
	1/11/2010	(11,883,473.94)		0.14%	0.000060%	
	1/12/2010	(11,419,024.83)		0.13%	0.000057%	
	1/13/2010	(9,707,792.90)		0.14%	0.000049%	
	1/14/2010	(6,808,713.60)		0.13%	0.000033%	
	1/15/2010	(6,397,257.56)		0.14%	0.000033%	
	1/16/2010	(6,397,282.29)		0.14%	0.000033%	
	1/17/2010	(6,397,307.02)		0.14%	0.000033%	
	1/18/2010	(6,397,331.75)		0.14%	0.000033%	
	1/19/2010				0.000000%	
	1/20/2010	(3,722,401.59)		0.17%	0.000024%	
	1/21/2010	(3,759,311.75)		0.17%	0.000023%	
	1/22/2010	(1,994,728.69)		0.16%	0.000012%	
	1/23/2010	(1,994,737.45)		0.16%	0.000012%	
	1/24/2010	(1,994,746.21)		0.16%	0.000012%	
	1/25/2010	(988,701.47)		0.15%	0.000005%	
	1/26/2010				0.000000%	
	1/27/2010				0.000000%	
	1/28/2010	(2,214,719.03)		0.14%	0.000012%	
Friday	1/29/2010	(805,285.95)		0.16%	0.000005%	
	1/30/2010	(805,289.62)		0.16%	0.000005%	
	1/31/2010	(805,293.30)		0.16%	0.000005%	0.16%
	2/1/2010	(428,347.46)		0.18%	0.000003%	
	2/2/2010	(680,235.63)		0.18%	0.000005%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	2/3/2010	(4,213,807.73)		0.17%	0.000027%	
	2/4/2010	(2,547,693.73)		0.15%	0.000015%	
	2/5/2010	(1,854,505.35)		0.17%	0.000012%	
	2/6/2010	(1,854,514.23)		0.17%	0.000012%	
	2/7/2010	(1,854,523.11)		0.17%	0.000012%	
	2/8/2010	(9,807,778.43)		0.16%	0.000060%	
	2/9/2010	(7,084,567.21)		0.16%	0.000041%	
	2/10/2010	(5,257,465.72)		0.16%	0.000031%	
	2/11/2010	(5,218,293.36)		0.16%	0.000031%	
	2/12/2010	(700,582.98)		0.16%	0.000004%	
	2/13/2010	(700,586.14)		0.16%	0.000004%	
	2/14/2010	(700,589.29)		0.16%	0.000004%	
	2/15/2010	(700,592.45)		0.16%	0.000004%	
	2/16/2010				0.000000%	
	2/17/2010				0.000000%	
	2/18/2010				0.000000%	
	2/19/2010	(1,310,432.30)		0.16%	0.000008%	
	2/20/2010	(1,310,438.21)		0.16%	0.000008%	
	2/21/2010	(1,310,444.12)		0.16%	0.000008%	
	2/22/2010				0.000000%	
	2/23/2010				0.000000%	
	2/24/2010				0.000000%	
	2/25/2010	(4,261,405.22)		0.18%	0.000028%	
Friday	**2/26/2010**	(2,984,115.84)		0.34%	0.000038%	
	2/27/2010	(2,984,144.32)		0.34%	0.000038%	
	2/28/2010	(2,984,172.80)		0.34%	0.000038%	0.19%
	3/1/2010	(3,025,500.39)		0.34%	0.000039%	
	3/2/2010	(1,464,631.97)		0.34%	0.000019%	
	3/3/2010	(3,386,774.11)		0.34%	0.000043%	
	3/4/2010				0.000000%	
	3/5/2010				0.000000%	
	3/6/2010				0.000000%	
	3/7/2010				0.000000%	
	3/8/2010	(1,891,591.87)		0.09%	0.000007%	
	3/9/2010				0.000000%	
	3/10/2010				0.000000%	
	3/11/2010				0.000000%	
	3/12/2010				0.000000%	
	3/13/2010				0.000000%	
	3/14/2010				0.000000%	
	3/15/2010	(69,238.00)		0.13%	0.000000%	
	3/16/2010	(851,840.76)		0.12%	0.000004%	
	3/17/2010				0.000000%	
	3/18/2010	(1,529,870.38)		0.11%	0.000006%	
	3/19/2010	(285,013.90)		0.12%	0.000001%	
	3/20/2010	(285,014.86)		0.12%	0.000001%	
	3/21/2010	(285,015.82)		0.12%	0.000001%	
	3/22/2010				0.000000%	
	3/23/2010				0.000000%	
	3/24/2010				0.000000%	
	3/25/2010				0.000000%	
	3/26/2010				0.000000%	
	3/27/2010				0.000000%	
	3/28/2010				0.000000%	
	3/29/2010				0.000000%	
	3/30/2010				0.000000%	
Wednesday	**3/31/2010**				0.000000%	0.19%
	4/1/2010				0.000000%	
	4/2/2010				0.000000%	
	4/3/2010				0.000000%	
	4/4/2010				0.000000%	
	4/5/2010	(1,965,701.90)		0.35%	0.000025%	
	4/6/2010	(529,098.82)		0.34%	0.000007%	
	4/7/2010				0.000000%	
	4/8/2010				0.000000%	
	4/9/2010	(1,965,631.57)		0.35%	0.000025%	
	4/10/2010	(1,965,650.42)		0.35%	0.000025%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	4/11/2010	(1,965,669.27)		0.35%	0.000025%	
	4/12/2010	(1,017,014.80)		0.14%	0.000005%	
	4/13/2010	(292,942.63)		0.13%	0.000001%	
	4/14/2010				0.000000%	
	4/15/2010				0.000000%	
	4/16/2010				0.000000%	
	4/17/2010				0.000000%	
	4/18/2010				0.000000%	
	4/19/2010				0.000000%	
	4/20/2010				0.000000%	
	4/21/2010				0.000000%	
	4/22/2010	(2,587,701.61)		0.19%	0.000019%	
	4/23/2010	(2,955,369.58)		0.21%	0.000023%	
	4/24/2010	(2,955,386.50)		0.21%	0.000023%	
	4/25/2010	(2,955,403.43)		0.21%	0.000023%	
	4/26/2010	(2,445,023.08)		0.21%	0.000019%	
	4/27/2010	(246,774.76)		0.14%	0.000001%	
	4/28/2010				0.000000%	
	4/29/2010				0.000000%	
Friday	4/30/2010				0.000000%	0.24%
	5/1/2010				0.000000%	
	5/2/2010				0.000000%	
	5/3/2010				0.000000%	
	5/4/2010				0.000000%	
	5/5/2010	(4,207,789.77)		0.21%	0.000033%	
	5/6/2010				0.000000%	
	5/7/2010				0.000000%	
	5/8/2010				0.000000%	
	5/9/2010				0.000000%	
	5/10/2010	(1,499,724.39)		0.21%	0.000011%	
	5/11/2010				0.000000%	
	5/12/2010				0.000000%	
	5/13/2010	(1,973,210.83)		0.21%	0.000015%	
	5/14/2010				0.000000%	
	5/15/2010				0.000000%	
	5/16/2010				0.000000%	
	5/17/2010				0.000000%	
	5/18/2010				0.000000%	
	5/19/2010				0.000000%	
	5/20/2010	(5,886,222.45)		0.37%	0.000081%	
	5/21/2010	(8,379,686.35)		0.37%	0.000116%	
	5/22/2010	(8,379,773.01)		0.37%	0.000116%	
	5/23/2010	(8,379,859.67)		0.37%	0.000116%	
	5/24/2010	(7,982,887.68)		0.21%	0.000062%	
	5/25/2010	(8,454,969.58)		0.23%	0.000072%	
	5/26/2010	(7,801,080.72)		0.21%	0.000061%	
	5/27/2010	(8,096,827.37)		0.21%	0.000063%	
Friday	**5/28/2010**	(6,714,455.19)		0.21%	0.000051%	
	5/29/2010	(6,714,493.79)		0.21%	0.000051%	
	5/30/2010	(6,714,532.39)		0.21%	0.000051%	
	5/31/2010	(6,714,570.99)		0.21%	0.000051%	0.25%
	6/1/2010	(9,961,957.21)		0.41%	0.000152%	
	6/2/2010	(7,987,501.35)		0.43%	0.000128%	
	6/3/2010	(9,970,786.75)		0.21%	0.000077%	
	6/4/2010	(12,630,007.31)		0.44%	0.000207%	
	6/5/2010	(12,630,162.28)		0.44%	0.000207%	
	6/6/2010	(12,630,317.26)		0.44%	0.000207%	
	6/7/2010	(10,254,423.24)		0.44%	0.000168%	
	6/8/2010	(13,853,111.57)		0.48%	0.000248%	
	6/9/2010	(12,336,127.02)		0.48%	0.000221%	
	6/10/2010	(7,635,055.52)		0.48%	0.000137%	
	6/11/2010	(7,136,902.23)		0.49%	0.000130%	
	6/12/2010	(7,136,999.79)		0.49%	0.000130%	
	6/13/2010	(7,137,097.36)		0.49%	0.000130%	
	6/14/2010	(1,555,138.80)		0.20%	0.000012%	
	6/15/2010	(136,551.25)		0.22%	0.000001%	
	6/16/2010	(1,993,532.16)		0.22%	0.000016%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	6/17/2010	(5,369,118.54)		0.23%	0.000046%	
	6/18/2010	(11,054,877.94)		0.51%	0.000209%	
	6/19/2010	(11,055,034.53)		0.51%	0.000209%	
	6/20/2010	(11,055,191.12)		0.51%	0.000209%	
	6/21/2010	(18,345,869.78)		0.50%	0.000341%	
	6/22/2010	(18,963,076.89)		0.51%	0.000359%	
	6/23/2010	(13,907,486.01)		0.51%	0.000264%	
	6/24/2010	(15,322,317.00)		0.51%	0.000288%	
	6/25/2010	(17,870,027.06)		0.51%	0.000336%	
	6/26/2010	(17,870,278.70)		0.51%	0.000336%	
	6/27/2010	(17,870,530.34)		0.51%	0.000336%	
	6/28/2010	(15,216,852.84)		0.51%	0.000285%	
	6/29/2010	(10,804,849.54)		0.22%	0.000089%	
Wednesday	**6/30/2010**	(4,268,088.07)		0.22%	0.000035%	0.41%
	7/1/2010	(3,114,597.13)		0.22%	0.000026%	
	7/2/2010	(8,998,072.35)		0.51%	0.000169%	
	7/3/2010	(8,998,198.89)		0.51%	0.000169%	
	7/4/2010	(8,998,325.43)		0.51%	0.000169%	
	7/5/2010	(8,998,451.98)		0.51%	0.000169%	
	7/6/2010	(16,840,714.00)		0.51%	0.000318%	
	7/7/2010	(15,885,618.65)		0.51%	0.000303%	
	7/8/2010	(17,570,497.30)		0.52%	0.000339%	
	7/9/2010	(15,733,222.11)		0.53%	0.000307%	
	7/10/2010	(15,733,452.20)		0.53%	0.000307%	
	7/11/2010	(15,733,682.30)		0.53%	0.000307%	
	7/12/2010	(10,120,555.82)		0.24%	0.000091%	
	7/13/2010	(6,916,138.06)		0.24%	0.000061%	
	7/14/2010	(5,129,849.60)		0.25%	0.000047%	
	7/15/2010	(8,280,344.85)		0.55%	0.000169%	
	7/16/2010	(7,665,461.13)		0.55%	0.000156%	
	7/17/2010	(7,665,578.27)		0.55%	0.000156%	
	7/18/2010	(7,665,695.41)		0.55%	0.000156%	
	7/19/2010	(6,763,188.17)		0.55%	0.000139%	
	7/20/2010	(5,290,130.83)		0.55%	0.000109%	
	7/21/2010	(1,025,136.47)		0.54%	0.000021%	
	7/22/2010	(3,377,170.12)		0.26%	0.000033%	
	7/23/2010	(1,157,855.69)		0.26%	0.000011%	
	7/24/2010	(1,157,863.98)		0.26%	0.000011%	
	7/25/2010	(1,157,872.26)		0.26%	0.000011%	
	7/26/2010	(1,127,190.71)		0.26%	0.000011%	
	7/27/2010	(284,757.10)		0.26%	0.000003%	
	7/28/2010				0.000000%	
	7/29/2010				0.000000%	
Friday	**7/30/2010**				0.000000%	
	7/31/2010				0.000000%	0.43%
	8/1/2010				0.000000%	
	8/2/2010				0.000000%	
	8/3/2010				0.000000%	
	8/4/2010				0.000000%	
	8/5/2010				0.000000%	
	8/6/2010				0.000000%	
	8/7/2010				0.000000%	
	8/8/2010				0.000000%	
	8/9/2010				0.000000%	
	8/10/2010				0.000000%	
	8/11/2010				0.000000%	
	8/12/2010				0.000000%	
	8/13/2010				0.000000%	
	8/14/2010				0.000000%	
	8/15/2010				0.000000%	
	8/16/2010				0.000000%	
	8/17/2010				0.000000%	
	8/18/2010				0.000000%	
	8/19/2010				0.000000%	
	8/20/2010				0.000000%	
	8/21/2010				0.000000%	
	8/22/2010				0.000000%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate	
	8/23/2010				0.000000%	
	8/24/2010				0.000000%	
	8/25/2010				0.000000%	
	8/26/2010				0.000000%	
	8/27/2010				0.000000%	
	8/28/2010				0.000000%	
	8/29/2010				0.000000%	
	8/30/2010				0.000000%	
Tuesday	8/31/2010				0.000000%	#DIV/0!
	9/1/2010				0.000000%	
	9/2/2010				0.000000%	
	9/3/2010				0.000000%	
	9/4/2010				0.000000%	
	9/5/2010				0.000000%	
	9/6/2010				0.000000%	
	9/7/2010				0.000000%	
	9/8/2010				0.000000%	
	9/9/2010				0.000000%	
	9/10/2010				0.000000%	
	9/11/2010				0.000000%	
	9/12/2010				0.000000%	
	9/13/2010				0.000000%	
	9/14/2010				0.000000%	
	9/15/2010				0.000000%	
	9/16/2010				0.000000%	
	9/17/2010				0.000000%	
	9/18/2010				0.000000%	
	9/19/2010				0.000000%	
	9/20/2010				0.000000%	
	9/21/2010				0.000000%	
	9/22/2010				0.000000%	
	9/23/2010				0.000000%	
	9/24/2010				0.000000%	
	9/25/2010				0.000000%	
	9/26/2010				0.000000%	
	9/27/2010				0.000000%	
	9/28/2010				0.000000%	
	9/29/2010				0.000000%	
Thursday	9/30/2010				0.000000%	#DIV/0!
	10/1/2010				0.000000%	
	10/2/2010				0.000000%	
	10/3/2010				0.000000%	
	10/4/2010				0.000000%	
	10/5/2010				0.000000%	
	10/6/2010				0.000000%	
	10/7/2010				0.000000%	
	10/8/2010				0.000000%	
	10/9/2010				0.000000%	
	10/10/2010				0.000000%	
	10/11/2010				0.000000%	
	10/12/2010				0.000000%	
	10/13/2010				0.000000%	
	10/14/2010				0.000000%	
	10/15/2010				0.000000%	
	10/16/2010				0.000000%	
	10/17/2010				0.000000%	
	10/18/2010				0.000000%	
	10/19/2010				0.000000%	
	10/20/2010				0.000000%	
	10/21/2010				0.000000%	
	10/22/2010				0.000000%	
	10/23/2010				0.000000%	
	10/24/2010				0.000000%	
	10/25/2010				0.000000%	
	10/26/2010				0.000000%	
	10/27/2010				0.000000%	
	10/28/2010				0.000000%	

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
Friday	**10/29/2010**				0.000000%
	10/30/2010				0.000000%
	10/31/2010				0.000000%
	11/1/2010				0.000000%
	11/2/2010				0.000000%
	11/3/2010				0.000000%
	11/4/2010				0.000000%
	11/5/2010				0.000000%
	11/6/2010				0.000000%
	11/7/2010				0.000000%
	11/8/2010				0.000000%
	11/9/2010				0.000000%
	11/10/2010				0.000000%
	11/11/2010				0.000000%
	11/12/2010				0.000000%
	11/13/2010				0.000000%
	11/14/2010				0.000000%
	11/15/2010				0.000000%
	11/16/2010				0.000000%
	11/17/2010				0.000000%
	11/18/2010				0.000000%
	11/19/2010				0.000000%
	11/20/2010				0.000000%
	11/21/2010				0.000000%
	11/22/2010				0.000000%
	11/23/2010				0.000000%
	11/24/2010				0.000000%
	11/25/2010				0.000000%
	11/26/2010				0.000000%
	11/27/2010				0.000000%
	11/28/2010				0.000000%
	11/29/2010				0.000000%
Tuesday	**11/30/2010**				0.000000%
	12/1/2010				0.000000%
	12/2/2010				0.000000%
	12/3/2010				0.000000%
	12/4/2010				0.000000%
	12/5/2010				0.000000%
	12/6/2010				0.000000%
	12/7/2010				0.000000%
	12/8/2010				0.000000%
	12/9/2010				0.000000%
	12/10/2010				0.000000%
	12/11/2010				0.000000%
	12/12/2010				0.000000%
	12/13/2010				0.000000%
	12/14/2010				0.000000%
	12/15/2010				0.000000%
	12/16/2010				0.000000%
	12/17/2010				0.000000%
	12/18/2010				0.000000%
	12/19/2010				0.000000%
	12/20/2010				0.000000%
	12/21/2010				0.000000%
	12/22/2010				0.000000%
	12/23/2010				0.000000%
	12/24/2010				0.000000%
	12/25/2010				0.000000%
	12/26/2010				0.000000%
	12/27/2010				0.000000%
	12/28/2010				0.000000%
	12/29/2010				0.000000%
	12/30/2010				0.000000%
Friday	**12/31/2010**				0.000000%
	1/1/2011				0.000000%
	1/2/2011				0.000000%
	1/3/2011				0.000000%

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
	1/4/2011				0.000000%
	1/5/2011				0.000000%
	1/6/2011				0.000000%
	1/7/2011				0.000000%
	1/8/2011				0.000000%
	1/9/2011				0.000000%
	1/10/2011				0.000000%
	1/11/2011				0.000000%
	1/12/2011				0.000000%
	1/13/2011				0.000000%
	1/14/2011				0.000000%
	1/15/2011				0.000000%
	1/16/2011				0.000000%
	1/17/2011				0.000000%
	1/18/2011				0.000000%
	1/19/2011				0.000000%
	1/20/2011				0.000000%
	1/21/2011				0.000000%
	1/22/2011				0.000000%
	1/23/2011				0.000000%
	1/24/2011				0.000000%
	1/25/2011				0.000000%
	1/26/2011				0.000000%
	1/27/2011				0.000000%
	1/28/2011				0.000000%
	1/29/2011				0.000000%
	1/30/2011				0.000000%
Monday	**1/31/2011**				0.000000%
	2/1/2011				0.000000%
	2/2/2011				0.000000%
	2/3/2011				0.000000%
	2/4/2011				0.000000%
	2/5/2011				0.000000%
	2/6/2011				0.000000%
	2/7/2011				0.000000%
	2/8/2011				0.000000%
	2/9/2011				0.000000%
	2/10/2011				0.000000%
	2/11/2011				0.000000%
	2/12/2011				0.000000%
	2/13/2011				0.000000%
	2/14/2011				0.000000%
	2/15/2011				0.000000%
	2/16/2011				0.000000%
	2/17/2011				0.000000%
	2/18/2011				0.000000%
	2/19/2011				0.000000%
	2/20/2011				0.000000%
	2/21/2011				0.000000%
	2/22/2011				0.000000%
	2/23/2011				0.000000%
	2/24/2011				0.000000%
	2/25/2011				0.000000%
	2/26/2011				0.000000%
	2/27/2011				0.000000%
Monday	**2/28/2011**				0.000000%
	3/1/2011				0.000000%
	3/2/2011				0.000000%
	3/3/2011				0.000000%
	3/4/2011				0.000000%
	3/5/2011				0.000000%
	3/6/2011				0.000000%
	3/7/2011				0.000000%
	3/8/2011				0.000000%
	3/9/2011				0.000000%
	3/10/2011				0.000000%
	3/11/2011				0.000000%

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
	3/12/2011				0.000000%
	3/13/2011				0.000000%
	3/14/2011				0.000000%
	3/15/2011				0.000000%
	3/16/2011				0.000000%
	3/17/2011				0.000000%
	3/18/2011				0.000000%
	3/19/2011				0.000000%
	3/20/2011				0.000000%
	3/21/2011				0.000000%
	3/22/2011				0.000000%
	3/23/2011				0.000000%
	3/24/2011				0.000000%
	3/25/2011				0.000000%
	3/26/2011				0.000000%
	3/27/2011				0.000000%
	3/28/2011				0.000000%
	3/29/2011				0.000000%
	3/30/2011				0.000000%
Thursday	**3/31/2011**				0.000000%
	4/1/2011				0.000000%
	4/2/2011				0.000000%
	4/3/2011				0.000000%
	4/4/2011				0.000000%
	4/5/2011				0.000000%
	4/6/2011				0.000000%
	4/7/2011				0.000000%
	4/8/2011				0.000000%
	4/9/2011				0.000000%
	4/10/2011				0.000000%
	4/11/2011				0.000000%
	4/12/2011				0.000000%
	4/13/2011				0.000000%
	4/14/2011				0.000000%
	4/15/2011				0.000000%
	4/16/2011				0.000000%
	4/17/2011				0.000000%
	4/18/2011				0.000000%
	4/19/2011				0.000000%
	4/20/2011				0.000000%
	4/21/2011				0.000000%
	4/22/2011				0.000000%
	4/23/2011				0.000000%
	4/24/2011				0.000000%
	4/25/2011				0.000000%
	4/26/2011				0.000000%
	4/27/2011				0.000000%
	4/28/2011				0.000000%
Friday	**4/29/2011**				0.000000%
	4/30/2011				0.000000%
	5/1/2011				0.000000%
	5/2/2011				0.000000%
	5/3/2011				0.000000%
	5/4/2011				0.000000%
	5/5/2011				0.000000%
	5/6/2011				0.000000%
	5/7/2011				0.000000%
	5/8/2011				0.000000%
	5/9/2011				0.000000%
	5/10/2011				0.000000%
	5/11/2011				0.000000%
	5/12/2011				0.000000%
	5/13/2011				0.000000%
	5/14/2011				0.000000%
	5/15/2011				0.000000%
	5/16/2011				0.000000%
	5/17/2011				0.000000%

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
	5/18/2011				0.000000%
	5/19/2011				0.000000%
	5/20/2011				0.000000%
	5/21/2011				0.000000%
	5/22/2011				0.000000%
	5/23/2011				0.000000%
	5/24/2011				0.000000%
	5/25/2011				0.000000%
	5/26/2011				0.000000%
	5/27/2011				0.000000%
	5/28/2011				0.000000%
	5/29/2011				0.000000%
	5/30/2011				0.000000%
Tuesday	**5/31/2011**				0.000000%
	6/1/2011				0.000000%
	6/2/2011				0.000000%
	6/3/2011				0.000000%
	6/4/2011				0.000000%
	6/5/2011				0.000000%
	6/6/2011				0.000000%
	6/7/2011				0.000000%
	6/8/2011				0.000000%
	6/9/2011				0.000000%
	6/10/2011				0.000000%
	6/11/2011				0.000000%
	6/12/2011				0.000000%
	6/13/2011				0.000000%
	6/14/2011				0.000000%
	6/15/2011				0.000000%
	6/16/2011				0.000000%
	6/17/2011				0.000000%
	6/18/2011				0.000000%
	6/19/2011				0.000000%
	6/20/2011				0.000000%
	6/21/2011				0.000000%
	6/22/2011				0.000000%
	6/23/2011				0.000000%
	6/24/2011				0.000000%
	6/25/2011				0.000000%
	6/26/2011				0.000000%
	6/27/2011				0.000000%
	6/28/2011				0.000000%
	6/29/2011				0.000000%
Thursday	**6/30/2011**				0.000000%
	7/1/2011				0.000000%
	7/2/2011				0.000000%
	7/3/2011				0.000000%
	7/4/2011				0.000000%
	7/5/2011				0.000000%
	7/6/2011				0.000000%
	7/7/2011				0.000000%
	7/8/2011				0.000000%
	7/9/2011				0.000000%
	7/10/2011				0.000000%
	7/11/2011				0.000000%
	7/12/2011				0.000000%
	7/13/2011				0.000000%
	7/14/2011				0.000000%
	7/15/2011				0.000000%
	7/16/2011				0.000000%
	7/17/2011				0.000000%
	7/18/2011				0.000000%
	7/19/2011				0.000000%
	7/20/2011				0.000000%
	7/21/2011				0.000000%
	7/22/2011				0.000000%
	7/23/2011				0.000000%

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
	7/24/2011				0.000000%
	7/25/2011				0.000000%
	7/26/2011				0.000000%
	7/27/2011				0.000000%
	7/28/2011				0.000000%
Friday	**7/29/2011**				0.000000%
	7/30/2011				0.000000%
	7/31/2011				0.000000%
	8/1/2011				0.000000%
	8/2/2011				0.000000%
	8/3/2011				0.000000%
	8/4/2011				0.000000%
	8/5/2011				0.000000%
	8/6/2011				0.000000%
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	8/8/2011				0.000000%
	8/9/2011				0.000000%
	8/10/2011				0.000000%
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	8/12/2011				0.000000%
	8/13/2011				0.000000%
	8/14/2011				0.000000%
	8/15/2011				0.000000%
	8/16/2011				0.000000%
	8/17/2011				0.000000%
	8/18/2011				0.000000%
	8/19/2011				0.000000%
	8/20/2011				0.000000%
	8/21/2011				0.000000%
	8/22/2011				0.000000%
	8/23/2011				0.000000%
	8/24/2011				0.000000%
	8/25/2011				0.000000%
	8/26/2011				0.000000%
	8/27/2011				0.000000%
	8/28/2011				0.000000%
	8/29/2011				0.000000%
	8/30/2011				0.000000%
Wednesday	**8/31/2011**				0.000000%
	9/1/2011				0.000000%
	9/2/2011				0.000000%
	9/3/2011				0.000000%
	9/4/2011				0.000000%
	9/5/2011				0.000000%
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	9/9/2011				0.000000%
	9/10/2011				0.000000%
	9/11/2011				0.000000%
	9/12/2011				0.000000%
	9/13/2011				0.000000%
	9/14/2011				0.000000%
	9/15/2011				0.000000%
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	9/17/2011				0.000000%
	9/18/2011				0.000000%
	9/19/2011				0.000000%
	9/20/2011				0.000000%
	9/21/2011				0.000000%
	9/22/2011				0.000000%
	9/23/2011				0.000000%
	9/24/2011				0.000000%
	9/25/2011				0.000000%
	9/26/2011				0.000000%
	9/27/2011				0.000000%
	9/28/2011				0.000000%

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
	9/29/2011				0.000000%
Friday	**9/30/2011**				0.000000%
	10/1/2011				0.000000%
	10/2/2011				0.000000%
	10/3/2011				0.000000%
	10/4/2011				0.000000%
	10/5/2011				0.000000%
	10/6/2011				0.000000%
	10/7/2011				0.000000%
	10/8/2011				0.000000%
	10/9/2011				0.000000%
	10/10/2011				0.000000%
	10/11/2011				0.000000%
	10/12/2011				0.000000%
	10/13/2011				0.000000%
	10/14/2011				0.000000%
	10/15/2011				0.000000%
	10/16/2011				0.000000%
	10/17/2011				0.000000%
	10/18/2011				0.000000%
	10/19/2011				0.000000%
	10/20/2011				0.000000%
	10/21/2011				0.000000%
	10/22/2011				0.000000%
	10/23/2011				0.000000%
	10/24/2011				0.000000%
	10/25/2011				0.000000%
	10/26/2011				0.000000%
	10/27/2011				0.000000%
	10/28/2011				0.000000%
	10/29/2011				0.000000%
	10/30/2011				0.000000%
Monday	**10/31/2011**				0.000000%
	11/1/2011				0.000000%
	11/2/2011				0.000000%
	11/3/2011				0.000000%
	11/4/2011				0.000000%
	11/5/2011				0.000000%
	11/6/2011				0.000000%
	11/7/2011				0.000000%
	11/8/2011				0.000000%
	11/9/2011				0.000000%
	11/10/2011				0.000000%
	11/11/2011				0.000000%
	11/12/2011				0.000000%
	11/13/2011				0.000000%
	11/14/2011				0.000000%
	11/15/2011				0.000000%
	11/16/2011				0.000000%
	11/17/2011				0.000000%
	11/18/2011				0.000000%
	11/19/2011				0.000000%
	11/20/2011				0.000000%
	11/21/2011				0.000000%
	11/22/2011				0.000000%
	11/23/2011				0.000000%
	11/24/2011				0.000000%
	11/25/2011				0.000000%
	11/26/2011				0.000000%
	11/27/2011				0.000000%
	11/28/2011				0.000000%
	11/29/2011				0.000000%
Wednesday	**11/30/2011**				0.000000%
	12/1/2011				0.000000%
	12/2/2011				0.000000%
	12/3/2011				0.000000%
	12/4/2011				0.000000%

Day of Week	Date	S-T Borrowed Balance	Borrowed Interest Rate	Borrowed Interest Rate	Weighted Average Borrowed Interest Rate
	12/5/2011				0.000000%
	12/6/2011				0.000000%
	12/7/2011				0.000000%
	12/8/2011				0.000000%
	12/9/2011				0.000000%
	12/10/2011				0.000000%
	12/11/2011				0.000000%
	12/12/2011				0.000000%
	12/13/2011				0.000000%
	12/14/2011				0.000000%
	12/15/2011				0.000000%
	12/16/2011				0.000000%
	12/17/2011				0.000000%
	12/18/2011				0.000000%
	12/19/2011				0.000000%
	12/20/2011				0.000000%
	12/21/2011				0.000000%
	12/22/2011				0.000000%
	12/23/2011				0.000000%
	12/24/2011				0.000000%
	12/25/2011				0.000000%
	12/26/2011				0.000000%
	12/27/2011				0.000000%
	12/28/2011				0.000000%
	12/29/2011				0.000000%
Friday	**12/30/2011**				0.000000%
	12/31/2011				0.000000%
	Sum Total All Daily Balances	**($26,991,615,090.48)**			**1.3010%**
	Divided By Number of Days in Year	**1,095**			
	Average Daily Balance	**($24,649,876.79)**			

Kentucky Power Company

REQUEST

Please provide Kentucky Power Company's annual income statements, balance sheets and cash flow statements over the most recent ten years (including 2010).

RESPONSE

Please see enclosed CD.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please list the top ten industrial customers for Kentucky Power in 2009, 2010 and 2011 by type of industry (do not provide customer name). Please provide total kWh sold to each and what percentage of total annual sales the sales to each industrial customer represents.

RESPONSE

Year	Top 10 Industrial Customers' Percentage of Total Annual kWh Sales
2009	34.18%
2010	33.82%
2011	37.16%

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-1 and Exhibit LPM-2.

a. Please provide a description and provide the amount of electric plant in service, net of accumulated depreciation and ADIT that the Company projects will be retired during the construction of the Big Sandy 2 DFGD projects. If the Company has not projected these
retirements, then please explain why it has not done so.

b. Please provide the monthly construction expenditures for each project comprising the Big Sandy 2 retrofits separated into major components, including, but not limited to, EPC by major contract, internal costs by major category, overheads by major category, contingencies, and AFUDC. Provide all assumptions, estimates, computations, and models used to quantify the cost of the project, including, but not limited to, the computation of the aFUDC rate and the monthly AFUDC accrual, each AEP and/or Kentucky Power Company overhead rate and the monthly overhead accruals.

c. Please further separate the monthly construction expenditures provided in response to part (b) of this question into the costs of demolition and removing existing physical plant, such as the precipitator and related equipment, and the costs of new construction for the DFGD.

d. Please provide a copy of all analyses, emails, and all other documents that AEP and/or the Company used to validate the cost estimate for the Big Sandy 2 DFGD compared to other DFGD installations in this and other countries.

e. Please provide a copy of all analyses, emails, and all other documents that AEP and/or the Company used to validate the cost estimate for the Big Sandy 2 DFGD compared to other DFD installations in this and other countries.

RESPONSE

a. At the time of the filing, KPCo had not projected any retirements. KPCo now expects to retire the precipitator as part of the process, but the reduction in capital less depreciation and ADIT has not been calculated.

b-c. The monthly construction expenditures will be developed as part of Phase IIb activities.

d-e. No such comparisons were performed.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Exhibit LPM -2.

a. Please provide all computational support for the depreciation expense amount, including, but not limited to, the depreciation rate(s), and a copy of the source document used for the depreciation rate(s).

b. Please explain why the Company subtracted an entire year of accumulated depreciation from the gross plant in service amount to compute the rate base used in the revenue requirement.

c. Please provide the computational support for the ADIT, including all assumptions regarding accelerated tax depreciation.

d. Please explain why the Company subtracted an entire year of ADIT from the gross plant in service amount to compute the rate base used in the revenue requirement.

e. Please identify and describe all available accelerated tax depreciation deductions for the Big Sandy 2 DFGD projects, including any special deductions for environmental compliance equipment. Cite to specific provisions of the Code and Regulations. In addition, please provide a copy of all tax research on the availability of accelerated tax depreciation deductions.

RESPONSE

a. Please see response to AG 1-28.

b. The Company provided an estimate of the cost for the project for the first year, which included an estimate of the first year of accumulated depreciation for a project with a 15-year life.

c. Please see electronic response to AG 1-28, page 2 of 14, which includes the basis for the ADIT calculation.

d. The Company provided an estimate of the cost for the project for the first year, which included an estimate of the first year of ADIT for a project with a 15-year life.

e. Objection: KPCo Objects to this portion of the question to the extent it calls for legal analysis or research, which would be protected by the attorney-client privilege and the attorney work product doctrine. Because the Company was providing an estimate of the cost for the project, no such research was performed for this filing. That research will be necessary to determine the amounts to be included in the environmental surcharge filing, based on the rules in effect when the project goes in-service.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to Exhibit LPM - 6

a. Please provide a description and provide the amount of electric plant in service that was retired during the construction of the four projects listed. Use the same definition of plant cost found in the AEP Interconnection Agreement in subdivision 6.2 used to compute the Member Weighted Average Investment Cost,

b. Please provide the revenue requirements that presently are included in base rates related to the electric plant in service that was retired during the construction of the four projects listed. Provide all assumptions, computations, and workpapers, including electronic spreadsheets, and a copy of all source documents relied on for your response.

c. Please confirm and demonstrate that none of the costs of the four new projects requested for recovery through the ECR is included in the Company's present base rates. This includes the plant-related costs and the operating expenses.

d. Please confirm that the definition of Member Weighted Investment Cost in subdivision 6.2 in the AEP Interconnection Agreement uses only the plant costs in plant accounts 310 to 316, 320 to 325, and 340 to 346 and does not include CWIP that has not been closed to plant in service.

e. Please confirm that the definition of Member Weighted Investment Cost in subdivision 6.2 in the AEP Interconnection Agreement uses only the plant costs "as of the end of the preceding year," meaning that plant additions in one year are not recovered from deficit members through the Primary Capacity Equalization Charge until the following year. If this is not correct, then please provide a correct description of how the definition is applied and the source of that methodology.

f. Please confirm that the Company will not include the costs of the Amos Common FGD HG Waste Water Treatment and Ash Pond Discharge Diffuser through the Kentucky ECR until the year after the projects are placed in service and the costs are closed to plant in service. If this does not reflect the Company's proposed timing for recovery of these costs through the ECR, then please describe the Company's timing and explain why the Commission should adopt its proposal.

RESPONSE

a. Amos Unit 3 Dry Fly Ash Disposal is the only project on the list that has had any retirements. The amount of the retirement was $3,934,211.

b. The Company is not able to make such a calculation.

c. The Company's 2011 Environmental Compliance Plan includes six (not four) new out-of-state environmental projects as shown on LPM-6. Because the in-service dates for these projects were after the September 30, 2009 test year used in the Company's 2009 rate case, these projects were not yet included as Plant in Service and the costs for these projects are not yet included in base rates. Further, Kentucky Power has not sought to amend its environmental compliance plan to recover the costs associated with these projects. Therefore KPCo's monthly Environmental Surcharge rates do not include recovery of investments on these projects.

d. Please see page 13, Section 6.211 of attachment to KIUC 1-14 that lists the accounts that are used in the derivation of the Member Weighted investment Cost. These accounts do not include Construction Work in Progress, account 107.

e. The statement is correct.

f. The statement is correct.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please indicate whether the amounts presently included in the Company's ECR for the costs of approved environmental projects incurred through the Primary Capacity Equalization Charge: a) include CWIP, and/or b) include investment costs closed to plant in service after the end of the preceding year. If CWIP amounts were included and/or investment costs that were not closed to plant in service as of the end of the preceding year were included, then please describe the CWIP projects and provide the amounts that were included in the most recent 12 months of ECR filings.

RESPONSE

CWIP is not included in the Company's ECR for the costs of approved environmental projects incurred through the Primary Capacity Equalization Charge. Once a project is placed in service (FERC Account 101) that cost is included in the Kentucky ECR filings. The FERC Account 101 plant investments placed in service are updated only once a year.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to the Company's response to the immediately preceding question. If either or both of these conditions have not previously been applied by the Company in computing the costs included in the Kentucky ECR on all such projects approved by the Commission in prior environmental compliance plan and surcharge proceedings, then please explain how the Company previously treated such costs.

RESPONSE

Please see the Company's response to KIUC 1-12.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please provide a copy of the most recent version of the AEP Interconnection Agreement.

RESPONSE

Please refer to Attachment 1 of this response.

WITNESS: Ranie K Wohnhas

COMPOSITE COPY

INTERCONNECTION AGREEMENT

BETWEEN

APPALACHIAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY *

INDIANA & MICHIGAN ELECTRIC COMPANY

AND WITH

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

AS AGENT

Dated: July 6, 1951, as modified and supplemented by:

Modification No. 1, August 1, 1951
Modification No. 2, September 20, 1962
Modification No. 3, April 1, 1975
Supplement No. 1 to
Modification No. 3, August 1, 1979
Supplement No. 2 to
Modification No. 3, August 27, 1979
Modification No. 4, November 1, 1980 *
Compliance Filing (FERC ordered), Opinion 266,
Docket Nos. ER84-579-006 and EL86-10-001

* Pursuant to Modification No. 4 the terms "Member" and "Members", whenever said terms appear in the 1951 Agreement, shall, on and after the time when Modification No. 4 shall become effective, include Columbus Company.

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 6th day of July, 1951 by and between APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY (Columbus Company), an Ohio corporation, INDIANA & MICHIGAN ELECTRIC COMPANY (Indiana Company), an Indiana corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually), being affiliated companies of an integrated public utility electric system, and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated electric utility companies.

The term "affiliate" shall include American Electric Power Company, Inc., Appalachian Power Company, Columbus and Southern Ohio Electric Company, Indiana & Michigan Electric Company, Kentucky Power Company, Ohio Power Company, Kingsport Power Company, Michigan Power Company, Wheeling Electric Company, and any subsidiaries, direct or indirect, of the foregoing.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated: (i) Appalachian Company in Tennessee, Virginia, and West Virginia, (ii) Kentucky Company in Kentucky, (iii) Ohio Company in Ohio and West Virginia, and (iv) Indiana Company in Indiana and Michigan, and (v) Columbus Company in Ohio, and

0.3 WHEREAS, the Members' electric facilities are now and have been for many years interconnected through their respective transmission facilities at a number of points (hereby designated and hereinafter called "Interconnection Points"), such facilities and the transmission facilities of other affiliated electric utility companies forming an integrated transmission network; and

0.4 WHEREAS, the transmission facilities of each Member are interconnected at a number of points with the transmission facilities of various non-affiliated electric utility companies, and those of Appalachian Company are interconnected with those of Tennessee Valley Authority, (said companies and Tennessee Valley Authority hereinafter sometimes called "Foreign Companies" when referred to collectively and "Foreign Company" when referred to individually; and

0.5 WHEREAS, the Members through cooperation with each other have been successful for some years in achieving substantial economies in the conduct of their business by coordinating the expansion and operation of their power supply facilities; and

0.6 WHEREAS, the Members believe that a fuller realization of the benefits and advantages through coordinated operation of their electric supply facilities will be better assured and more efficiently and economically achieved by having such operation directed and supervised by a centrally located organization skilled in the technique of system operation on a large scale and thoroughly familiar with the power supply facilities of the Members, and that their participation in the coordinated expansion and operation of their facilities will be simplified and facilitated by having such procedures conducted by a single clearing agent; and

0.7 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services for them.

0.8 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto agree as follows:

ARTICLE I

PROVISIONS FOR, AND CONTINUITY OF INTERCONNECTED OPERATION

1.1 Throughout the duration of this agreement the systems of the Members shall be operated in continuous synchronism through each of the various lines interconnecting their respective systems; provided, however, if synchronous operation of the systems through a particular line or lines becomes interrupted because of reasons beyond the control of any Member or because of scheduled maintenance that has been agreed to by the Members, the Members shall cooperate so as to remove the cause of such interruption as soon as practicable and restore the affected line or lines to normal operating condition.

1.2 Each Member shall keep the portions of the lines interconnecting their respective systems, together with all associated facilities and appurtenances, that are located on their respective sides of the Interconnection Points in a sutiable condition of repair at all times in order that said lines will operate in a reliable and satisfactory manner and that reduction in their capacity will be avoided.

ARTICLE 2

OPERATING COMMITTEE

2.1 The parties herein shall appoint representatives to act as the "Operating Committee" in cooperation with each other and the Agent in the coordination and operation and/or use of the electric power sources of or available to the Members and of their transmission and distribution and substation facilities to the end that the advantages to be derived thereunder may be realized to the fullest practicable extent.

2.2 Each Member shall designate in writing delivered to the other Members and Agent, the person who is to act as its representative on said committee and the person or persons who may serve as alternate whenever such representative is unable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said committee. Such person shall act as chairman of the Operating Committee and shall be known as the "Pool Manager". All such representatives or alternates so designated shall be fully authorized to cooperate with the other representatives or alternates in all matters described in this agreement as responsibilities of the Operating Committee.

ARTICLE 3

AGENT'S RESPONSIBILITIES

3.1 For the purpose of carrying out the coordinated operation of the generating and transmission facilities of Members and the most efficient use of the energy produced by them and of other energy available to them, the Members hereby delegate to Agent and Agent hereby accepts the responsibility of supervising and directing such operation and use, and in furtherance thereof Agent agrees as follows; viz:

3.11 To coordinate the operation of the electric power sources of or available to the Members, which include their own generating stations and electric power available to them through interconnection with affiliated companies other than Members and Foreign Companies.

3.12 To arrange for and conduct such meetings of the Operating Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this agreement.

3.13 To prepare and collect such log sheets and other records as may be needed to afford a clear history of the electric power and energy supplied under this agreement. Preparation and collection of such log sheets and other record shall be coordinated with similar responsibilities of the Members as provided for under Article 9.

3.14 To render to each Member as promptly as possible after the end of each calendar month a statement setting forth the electric power and energy transactions carried out during such month pursuant to the provisions of this agreement in such detail and with such segregations as may be needed for operating records or for settlements hereunder.

3.15 To make arrangements with Foreign Companies on behalf of the Members for the purchase, sale, or interchange of power and energy between such companies and the Members, such arrangements to be made in addition to similar arrangements to be made under agreements between an individual Member and a Foreign Company and to be made whenever in the judgment of the Members the effecting of matters of operation and contract related thereto can be simplified and their performance facilitated.

3.16 To carry out cash settlements for electric power and energy supplied under this agreement. Settlements by the Members shall be made for each calendar month through an account (hereby designated and hereinafter called "SYSTEM ACCOUNT") to be administered by Agent. Payments to or from such account shall be made to or by Agent as clearing agent of the account. The total of the payments made by Members to the SYSTEM ACCOUNT for a particular month shall be equal to the payments made to the Members from the SYSTEM ACCOUNT for such month.

ARTICLE 4

MEMBERS' OBLIGATIONS AND RIGHTS

4.1 For the purpose of obtaining the most efficient coordinated expansion and operation of their electric power supply facilities the Members hereby agree to operate and utilize their electric power sources under the direction of the Pool Manager in such manner that each Member shall receive at all times sufficient electric power and energy from such sources to meet its specific load obligations.

Each member shall, to the extent practicable, install or have available to it under contract such capacity as is necessary to supply all of the requirements of its own customers.

4.2 The Members agree that their electric power sources, which shall include all the generating stations owned by the Members and all electric power available to them through interconnection with affiliated companies other than Members and Foreign Companies, shall be used as needed to carry the combined load obligations of the Member under the direction of the Pool Manager. Each Member in return shall receive at all times sufficient electric power and energy from such sources to meet the specific load obligations of such Member.

4.3 The Members recognize that in carrying out the interconnected operation of their respective transmission systems as herein provided, electric energy being received by a portion of a particular Member's transmission system from another portion of such system or from the system of another interconnected company, or electric energy being delivered by a portion of a particular Member's transmission system to another portion of such system or to the system of another interconnected company, may flow over the transmission system of another Member. In respect of such flow of electric energy (hereinafter called "Energy Transfer") the Members agree that such Energy Transfer over their respective transmission facilities shall be permitted whenever it occurs, and, except as may be specifically agreed to otherwise by the Members, no Member shall make a charge at any time to another Member to permit such Energy Transfer. Electric power and energy associated with such Energy Transfer, including electrical losses associated therewith, shall be accounted for each clockhour. Proper consideration shall be given to such electrical losses in accordance with the manner determined and agreed upon by the Operating Committee, and such consideration shall be fully in accord with the provisions of LINE LOSS FACTOR as defined under subdivision 5.15 of Article 5.

ARTICLE 5

DEFINITIONS OF LOAD, CAPACITY, AND ENERGY CLASSES
AND RELATED FACTORS ASSOCIATED WITH SETTLEMENTS
FOR POWER SUPPLIED FROM MEMBER'S ELECTRIC POWER SOURCES

5.1 Load, capacity, and energy shall be designated and allocated to various classes for the purposes of effecting settlements under this agreement. Load, capacity, and energy classes and related factors associated with the settlement for electric power and energy supplied from electric power sources of the Members are defined as follows; viz:

Load

5.2 MEMBER LOAD OBLIGATION - A Member's internal load plus any firm power sales to Foreign Companies and to affiliated companies other than Members. Principally characterized by the Member assuming the load obligation as its own firm power commitment and by the Member retaining advantages accruing from meeting the load.

5.3 SYSTEM LOAD OBLIGATION - Load obligation shared proportionately by the Members where one Member or Agent will act as Agent of the Members in meeting the commitment; principally characterized by the load not being considered as a part of any MEMBER LOAD OBLIGATION.

(Examples of SYSTEM LOAD OBLIGATIONS are electric power and energy deliveries made to Foreign Companies under emergency and storage power arrangements with such companies.)

5.4 MEMBER DEMAND - MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.

5.5 MEMBER MAXIMUM DEMAND - The MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by said Member during the twelve consecutive calendar months next preceding such calendar month.

5.6 MEMBER LOAD RATIO - The ratio of a particular Member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the five MEMBER MAXIMUM DEMANDS in effect for such month.

Capacity

5.7 MEMBER PRIMARY CAPACITY - The aggregate capacity of the electric power sources of a particular Member, in Kilowatts, that is normally expected to be available to carry Load. Such capacity shall include (i) the capacity installed at the generating stations owned by the Member and (ii) the capacity available to that Member through interconnection arrangements with affiliated companies or Foreign Companies, if so designated by the Operating Committee with the approval of the Members.

5.7.1 All determinations by the Operating Committee pursuant to (ii) of Section 5.7 with respect to purchases of capacity from non-affiliated companies shall take into account, but shall not be limited to, the following circumstances and considerations: (1) the term during which such capacity will be available, a commitment from a reliable source of power and energy for at least five years being normally regarded as appropriate for inclusion as a capacity source of a particular Member, with purchases of a short or intermediate duration being normally regarded as System purchases under Article 7; (2) whether the availability of the purchased capacity will be comparable to the availability of the installed primary capacity of the Members, although the Operating Committee may make adjustments in the quantity of purchased capacity to be included as Member Primary Capacity to give effect to any disparity in the availability of such purchased capacity; (3) the need on the part of a Member with a Member Primary Capacity deficit of an extended nature to rectify or alleviate such deficit and the interest of all Members in maintaining an equalization among the Members of capacity resources over a period of time.

5.7.2 In the event that arrangements are made hereunder for any Member to make capacity available to an affiliated company or to a Foreign Company through the sale by such Member, for its own account, of unit capacity or other non-firm capacity, the amount of the capacity so sold shall be excluded from the Primary Capacity of such Member.

5.8 SYSTEM PRIMARY CAPACITY - The sum of the MEMBER PRIMARY CAPACITY of all the Members.

5.9 MEMBER PRIMARY CAPACITY RESERVATION - SYSTEM PRIMARY CAPACITY multiplied by the MEMBER LOAD RATIO of a particular Member.

5.10 MEMBER PRIMARY CAPACITY SURPLUS - Difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY exceeds such MEMBER PRIMARY CAPACITY RESERVATION.

5.11 MEMBER PRIMARY CAPACITY DEFICIT - Difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY is less than such MEMBER PRIMARY CAPACITY RESERVATION.

Energy

5.12 POOL - Electric energy delivered by one Member, from its MEMBER PRIMARY CAPACITY, to another Member shall be considered to be energy delivered to the POOL by the former Member and received from the POOL by the latter Member.

Electric energy delivered by a Foreign Company to a Member, other than energy associated with a Member's MEMBER PRIMARY CAPACITY, shall be considered to be energy delivered to the POOL. Electric energy delivered by a Member to a Foreign Company to meet a SYSTEM LOAD OBLIGATION shall be considered to be energy delivered by the POOL to the Foreign Company.

5.13 PRIMARY ENERGY - Electric energy delivered to the POOL from the MEMBER PRIMARY CAPACITY of a particular Member to meet another Member's deficiency in capacity. The deficiency may be caused by one or both of two reasons, the total MEMBER PRIMARY CAPACITY of a particular Member may not be great enough to meet its MEMBER LOAD OBLIGATION or a Member may have a portion of its MEMBER PRIMARY CAPACITY out of service for maintenance and the remainder may not be great enough to meet its MEMBER LOAD OBLIGATION.

5.14 ECONOMY ENERGY - Electric energy delivered to the POOL from the MEMBER RRIMARY CAPACITY of a particular Member to displace energy that otherwise would be supplied by less efficient MEMBER PRIMARY CAPACITY of another Member to meet its MEMBER LOAD OBLIGATION.

5.15 LINE LOSS FACTOR - The transmission electrical loss factor to be applied for settlement purposes to a particular metered quantity of energy delivered to the POOL by a Member. The Operating Committee shall determine and agree upon the LINE LOSS FACTOR required, such determinations to be governed by the understanding that the Member receiving such energy shall bear the entire loss caused in transmitting such energy over the facilities of the delivering Member and over the facilities of any other party whose system may be used for such delivery.

ARTICLE 6

SETTLEMENTS FOR POWER AND ENERGY
SUPPLIED FROM MEMBER'S ELECTRIC POWER SOURCES

6.1 As promptly as practicable following the end of each month (all references to month mean calendar month), for electric power and energy supplied under this agreement during such month from SYSTEM PRIMARY CAPACITY, the Members shall carry out cash settlements through the SYSTEM ACCOUNT in accordance with the following; viz:

Primary Capacity Equalization Charge

6.2 For each kilowatt of MEMBER PRIMARY CAPACITY SURPLUS each Member having such surplus during any month shall receive payment from the SYSTEM ACCOUNT at a rate per kilowatt per month equal to the MEMBER PRIMARY CAPACITY INVESTMENT RATE plus the MEMBER PRIMARY CAPACITY FIXED OPERATING RATE, as hereinbelow defined, applicable to the particular surplus.

6.21 The MEMBER PRIMARY CAPACITY INVESTMENT RATE chargeable against the SYSTEM ACCOUNT for any calendar month by a particular Member shall be equal to the product of (A) the MEMBER WEIGHTED AVERAGE INVESTMENT COST, determined pursuant to subdivision 6.211 below, and (B) the MONTHLY CARRYING CHARGE FACTOR, determined pursuant to subdivision 6.212 below.

6.211 The MEMBER WEIGHTED AVERAGE INVESTMENT COST shall be equal to the ratio of (i) the total installed cost of production plant of the generation stations, other than hydro, classified as part of a particular Member's MEMBER PRIMARY CAPACITY to (ii) the total kilowatt capability of such generating stations. The total installed cost of production plant used in the determination of the MEMBER WEIGHTED AVERAGE INVESTMENT COST, as described above, shall be the total cost of such plant for the aforesaid generating stations included, as of the end of the next preceding year, in Accounts 310 to 316, inclusive, Accounts 320 to 325, inclusive and Accounts 340 to 346, inclusive, of the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission for Public Utilities and Licensees, as in effect on January 1, 1975.

6.212 The MONTHLY CARRYING CHARGE FACTOR shall be 0.0137, or such larger amount as shall be established by order of the Federal Energy Regulatory Commission issued upon rehearing or reconsideration of its Opinion No. 50, issued July 27, 1979 in Docket No. E-9408.

6.22 The MEMBER PRIMARY CAPACITY FIXED OPERATING RATE chargeable against the SYSTEM ACCOUNT for any calendar month by a particular Member shall be equal to the weighted average fixed operating cost as hereinbelow defined, incurred by said Member during such month. Such weighted average fixed operating cost for purposes hereof shall be equal to the ratio of the fixed operating expense, i.e., the total production expenses minus the fuel and one-half of the maintenance expenses, incurred by a particular Member during a month at the generating stations other than hydro, classified as a part of its MEMBER PRIMARY CAPACITY to the total kilowatt capability of such generating stations.

6.3 For each kilowatt of MEMBER PRIMARY CAPACITY DEFICIT, any Member having such deficit during any month shall make payment into the SYSTEM ACCOUNT at a rate per kilowatt per month equal to the total payments from the SYSTEM ACCOUNT during any such month, determined pursuant to subdivision 6.2 above, divided by the total kilowatts of MEMBER PRIMARY CAPACITY DEFICITS for such month.

Primary Energy Charge

6.4 For PRIMARY ENERGY delivered to the POOL during any month by any Member, the Member so delivering such energy shall receive payment from the SYSTEM ACCOUNT at a rate per kilowatt-hour equal to said Member's MEMBER PRIMARY ENERGY RATE, as hereinbelow defined, for such month. The MEMBER PRIMARY ENERGY RATE chargeable against the SYSTEM ACCOUNT for any month by said Member shall be equal to the Member's weighted average variable production cost, as hereinbelow defined, for such month. Such weighted average variable production cost for purposes hereof shall be equal to the ratio of the sum of the fuel and one-half of the maintenance expenses incurred by said Member during a month at the generating stations other than hydro, classified as part of such Member's MEMBER PRIMARY CAPACITY to the total kilowatt-hours of net generation at said generating stations during such month.

6.5 For PRIMARY ENERGY received from the POOL during any month by any Member, said Member shall make payment into the SYSTEM ACCOUNT for energy so received at a rate per kilowatt-hour equal to the MEMBER PRIMARY ENERGY RATE payable from the SYSTEM ACCOUNT to the other Members for such month for such PRIMARY ENERGY. THe rate applicable to such PRIMARY ENERGY shall be determined from clock-hour records to be kept by Agent as provided under Article 3. Such records shall indicate the receiving Member and supplying Member for each kilowatt-hour classified as PRIMARY ENERGY.

Economy Energy Charge

6.6 For ECONOMY ENERGY delivered to the POOL during any month the Member delivering such energy shall receive payment from and the Member receiving such energy shall make payment to the SYSTEM ACCOUNT at the ECONOMY ENERGY RATE, as hereinbelow defined, applicable to the energy so delivered and received. The ECONOMY ENERGY RATE applicable to a particular kilowatt-hour of ECONOMY ENERGY shall be equal to the out-of-pocket cost of delivering said kilowatt-hour to the POOL plus one-half the difference between such cost and the out-of-pocket cost of generation avoided by the Member receiving such energy. Said kilowatt-hour shall be considered to be supplied from the highest cost source carrying load to meet MEMBER LOAD OBLIGATIONS of the supplying Member, excluding sources operated for minimum operating requirements, and its out-of-pocket cost shall include fuel expense and an appropriate portion of maintenance expense of generating facilities. The cost of generation avoided by the Member receiving said kilowatt-hour of ECONOMY ENERGY shall be considered to be the out-of-pocket cost that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the receiving Member. Such out-of-pocket cost shall include cost of fuel and an appropriate portion of maintenance expense of generating facilities. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of the supplying Member and to the avoided cost of the receiving Member shall be determined and agreed upon by the Operating Committee.

System Primary Energy Rate

6.7 Settlements for various classes of electric power and energy delivered under transactions with Foreign Companies shall include the use of a rate referred to as SYSTEM PRIMARY ENERGY RATE. For purposes of this agreement, the SYSTEM PRIMARY ENERGY RATE chargeable for any month shall be equal to the weighted average variable operating cost, as hereinbelow defined, incurred during such month at the generating stations, other than hydro, classified as part of the SYSTEM PRIMARY CAPACITY. Such weighted average variable operating cost for purposes hereof shall be equal to the ratio of the variable production expenses, i.e., the fuel and one-half of the maintenance expenses, incurred during a month at the generating stations, other than hydro, classified as part of the SYSTEM PRIMARY CAPACITY to the total kilowatt-hours of net generation generated at said generating stations during such month.

ARTICLE 7

TRANSACTIONS WITH FOREIGN COMPANIES

7.1 As promptly as practicable following the end of each month, cash settlements by the Members through the SYSTEM ACCOUNT for power transactions carried out in their behalf with, Foreign Companies during such month shall be effected in accordance with the principles and procedures provided therefor under this Article 7. Any sale of power included in a Member's MEMBER LOAD OBLIGATION and any purchase of power included in a Member's MEMBER PRIMARY CAPACITY shall be excluded from such transactions. All other types of transactions carried out by any Member or on behalf of the Members with any Foreign Company shall be considered a transaction made on behalf of the collective interest of the Members. Costs and benefits associated with such transactions shall be shared proportionately as hereinbelow provided.

Settlement For Power And Energy Purchases From Foreign Companies

Power and Energy Purchases other than Economy Energy

7.2 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy, other than ECONOMY ENERGY PURCHASE from any Foreign Company shall be as follows; viz:

7.21 SYSTEM PURCHASE FROM FOREIGN COMPANY - All energy purchased from a Foreign Company either by a particular Member or by the Members collectively through arrangements made on their behalf by Agent, except ECONOMY ENERGY or such energy as may be purchased to meet a SYSTEM LOAD OBLIGATION (settlement for energy so purchased that is supplied to another Foreign Company is provided for under subdivisions 7.5 and 7.7 below.)

7.22 MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, the SYSTEM PURCHASE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.23 MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds such quantity of energy delivered to said Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.24 MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member is less than such quantity of energy delivered to said Member by the Foreign Company, the difference between such quantities is the MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.25 MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM PURCHASE from FOREIGN COMPANY delivered to the POOL by the Member, the difference between such quantities is the MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.26 MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM PURCHASE FROM FOREIGN COMPANY received from the POOL by said Member, the difference between such quantities is the MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.3 To effect a proportionate sharing of the cost of any SYSTEM PURCHASE FROM FOREIGN COMPANY, purchases so made from each Foreign Company shall be treated separately as follows:

7.31 At the end of each month, from data supplied by the Members, Agent shall determine the cost of SYSTEM PURCHASE FROM FOREIGN COMPANY.

7.32 The total cost so determined multiplied by the [MEMBER] LOAD RATIO of a particular Member shall be the gross amount chargeable to said Member.

7.33 If a particular Member has established a MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY, the adjusted gross amount chargeable to the Member shall equal the sum of the gross amount determined under subdivision 7.32 above plus the amount chargeable to the Member for the MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY. The rate applicable to such deficit shall be the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.34 If a particular Member has established a MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY, the adjusted gross amount chargeable to the Member shall equal the difference between the gross amount determined under subdivision 7.32 above and the amount to be credited to the Member for the MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY. The rate applicable to such surplus shall be the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.35 If the adjusted gross amount chargeable to a particular Member for any month as determined under either subdivisions 7.33 or 7.34 is greater than the payment make by said Member to the Foreign Company for the SYSTEM

PURCHASE FROM FOREIGN COMPANY, said Member shall make payment into the SYSTEM ACCOUNT of the difference between such amount and payment. Conversely, if the amount so determined for a particular Member is less than the Member's aforesaid payment to the Foreign Company, such Member shall receive payment from the SYSTEM ACCOUNT of the difference between such amount and such payment to the Foreign Company.

Economy Energy Purchases

7.4 Settlement by the Members through the SYSTEM ACCOUNT for ECONOMY ENERGY PURCHASE from a Foreign Company shall be governed by the principle that the saving in production expense realized by the System (the term "System" as used in this agreement refers to the electric facilities of the Members viewed as a unit) shall be shared by the Members in proportion to their respective MEMBER LOAD RATIOS.

(The following illustrates the application of the principle and procedure for effecting such settlements:

It is assumed that Appalachian Company has purchased a block of ECONOMY ENERGY PURCHASE at a rate of 1.00 mill per kilowatt-hour which has displaced generation at Twin Branch Station of Indiana Company; the production expense saving to Indiana Company being 2.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy shall be at the following rates: (1) pay Appalachian Company at a rate per kilowatt-hour equal to the sum of 1.00 mill plus the product of 2.00 mills times Appalachian Company's MEMBER LOAD RATIO, (2) pay Ohio Company at a rate per kilowatt-hour equal to the product of 2.00 mills times Ohio Company's MEMBER LOAD RATIO, and (3) charge Indiana Company at a rate per kilowatt-hour equal to the sum of 1.00 mill plus the product of 2.00 mills times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS.)

For the purpose of this agreement, the cost of generation avoided by the System in receiving a kilowatt-hour of ECONOMY ENERGY PURCHASE shall be considered to be the out-of-pocket cost, i.e., fuel expense and an appropriate portion of maintenance expense of generating facilities that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the System. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of such generating facilities shall be determined and agreed upon by the Operating Committee.

Settlement for Power Sales to Foreign Companies

7.5 Settlement by the Members through the SYSTEM ACCOUNT for electric power and energy sales to Foreign Companies shall be governed by the principle that the difference between the amount charged a Foreign Company for the power and energy supplied under such a sale and the production expenses, i.e., out-of-pocket costs incurred by the System in making such supply, shall be shared by the Members in proportion to the respective MEMBER LOAD RATIOS. Electric Power and energy for such sales shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying power to the System under arrangements with Foreign Companies.

(The following illustrates the application of the principles and procedures for effecting such settlements:

It is assumed that Indiana Company has sold a block of energy at a rate of 4.00 mills per kilowatt-hour which has been supplied by carrying a block of load that would not otherwise be carried at Philo Station of Ohio Company, the out-of-pocket cost incurred by Ohio Company being 3.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy would be at the following rates: (1) charge

Indiana Company at a rate per kilowatt-hour equal to the sum of 3.00 mills plus the product of 1.00 mill times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS, (2) pay Ohio company at a rate per kilowatt-hour equal to the sum of 3.00 mills and the product of 1.00 mill times Ohio Company's MEMBER LOAD RATIO, and (3) pay Appalachian Company at a rate per kilowatt-hour equal to the product of 1.00 mill times Appalachian Company's MEMBER LOAD RATIO.)

Settlement For Power and Energy Received Under
Interchange Arrangements With Foreign Companies

Power and Energy Received other
than Interchange Economy Energy

7.6 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy received, other than INTERCHANGE ECONOMY ENERGY, from any Foreign Company under interchange arrangements which require no cash settlements shall be as follows; viz:

7.61 SYSTEM INTERCHANGE FROM FOREIGN COMPANY - All energy received from Foreign Company by either a particular Member or by the Members collectively through arrangements made on their behalf by Agent, which requires no cash settlement, except INTERCHANGE ECONOMY ENERGY.

7.62 MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, the SYSTEM INTERCHANGE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.63 MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM

INTERCHANGE FROM FOREIGN COMPANY of such Member for such month.

7.64 MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member is less than the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.65 MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM INTERCHANGE FROM FOREIGN COMPANY delivered to the POOL by said Member, the difference between such quantities is the MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.66 MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM INTERCHANGE FROM FOREIGN COMPANY received from the POOL by said Member, the difference between such quantities is the MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.7 To effect a proportionate sharing of the benefits of SYSTEM INTERCHANGE FROM FOREIGN COMPANY, electric energy so received from each Foreign Company shall be treated separately as follows:

7.71 If a particular Member has established a MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY, said Member shall make payment into the SYSTEM ACCOUNT for the kilowatt-hours of such deficit at the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.72 If a particular Member has established a MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY, said Member shall receive payment from the SYSTEM ACCOUNT for the kilowatt-hours of such surplus at the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

Interchange Economy Energy

7.8 The priciples described under subdivision 7.4 above for the settlement of ECONOMY ENERGY PURCHASE shall also govern the settlements by the Members through the SYSTEM ACCOUNT for INTERCHANGE ECONOMY ENERGY received from a Foreign Company. It shall be assumed for the purpose of such settlement that payment to the Foreign Company for INTERCHANGE ECONOMY ENERGY was made at a rate of zero mills per kilowatt-hour.

Settlements For Power Delivered Under Interchange Arrangements With Interconnected Foreign Companies

7.9 Settlement hereunder for electric power and energy (hereinafter called "SYSTEM INTERCHANGE TO FOREIGN COMPANY") delivered to any Foreign Company under interchange arrangements with either a particular Member or with the Members collectively through arrangements made on their behalf by Agent, which require no cash settlements, will be governed by the principle that the production expenses, i.e., out-of-pocket costs incurred by the System in making such deliveries, shall be shared by the

Members in proportion to their respective MEMBER LOAD RATIOS.

(The following illustrates the application of the principle and procedure for effecting such settlements:

It is assumed that Appalachian Company has delivered a block of SYSTEM INTERCHANGE TO FOREIGN COMPANY which has been supplied by carrying a block of load that would not otherwise be carried at Windsor Station of Ohio Company; the out-of-pocket cost incurred by Ohio Company being 3.50 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy shall be at the following rates: (1) charge Appalachian Company and Indiana Company at rates per kilowatt-hour equal to the product of 3.50 mills per kilowatt-hour and their respective MEMBER LOAD RATIOS, and (2) pay Ohio Company at a rate equal to the sum of the rates charged Appalachian Company and Indiana.)

As described under subdivision 7.5 above, electric power and energy for sales to Foreign Companies shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying electric power and energy to the System under arrangements with Foreign Companies. Similarly, following the determination and designation of such source for the aforesaid sales, electric power and energy for SYSTEM INTERCHANGE TO FOREIGN COMPANY deliveries shall be considered to be supplied from the higher cost of the balance of said two sources.

ARTICLE 8

DELIVERY POINTS, METERING POINTS AND METERING

Delivery Points

8.1 All electric energy delivered under this agreement shall be of the character commonly known as three-phase sixty-cycle energy, and shall be delivered at the various Interconnection points where the transmission systems of the Members are interconnected at the nominal unregulated voltage designated for such points, and at such other points and voltages as may be determined and agreed upon by the Members.

Metering Points

8.2 Electric power and energy supplied and delivered by one Member to another Member shall be measured by suitable metering equipment to be provided, owned, and maintained by the Members at such metering points as are determined and agreed upon by them.

Metering

8.3 Suitable metering equipment at metering points as provided under subdivision 8.2 above shall include electric meters which shall give for each direction of flow the following quantities (1) an automatic record for each clock-hour of kilowatt-hours and (2) a continuous integrating record of the kilowatt-hours.

8.4 Measurements of electric energy for the purpose of effecting settlements under this agreement shall be made by standard types of electric meters, installed and maintained by the owner at the metering points as provided under subdivision 8.2 above. The timing devices of all meters having such devices shall be maintained in time synchronism as closely as practicable. The meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be tested or adjusted. For the purpose of checking the records of the metering equipment installed by any Member as hereinabove provided, the other Members shall have the right to install check metering equipment at the aforesaid metering points. Metering equipment so installed by one Member on the premises of another Member shall be owned and maintained by the Member installing such equipment. Upon termination of this agreement the Member owning such metering equipment shall remove it from the premises of the other Member. Authorized representatives of any Member shall have access at all reasonable hours to the premises where the meters are located and to the records made by the meters.

8.5 The aforesaid metering equipment shall be tested by the owner at suitable intervals and its accuracy of registration maintained in accordance with good practice. On request of any Member, special tests shall be made at the expense of the Member requesting such special test.

8.6 If on any test of metering equipment, an inaccuracy shall be disclosed exceeding two percent, the account between the Members for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the thirty-day period immediately preceding the day of the test or (2) for the period that such inaccuracy may be determined to have existed. Should the metering equipment as hereinabove provided for fail to register at any time, the electric power and energy delivered shall be determined from the check meters, if installed, or otherwise shall be determined from the best available data.

ARTICLE 9

RECORDS AND STATEMENTS

9.1 In addition to meter records to be kept by the Members as provided under Article 8, the Members shall keep in duplicate such log sheets and other records as may be needed to afford a clear history of the various deliveries of electric power and energy made pursuant to the provisions of this agreement. The originals of log sheets and other records shall be retained by the Member keeping the records and the duplicates shall be delivered as determined and agreed upon by the Operating Committee.

ARTICLE 10

TAXES

10.1 If at any time during the duration of this agreement, there should be levied and/or assessed against any Member any tax by any taxing authority in respect of the electric power and energy generated, purchased, sold, imported, transmitted, interchanged, or exchanged by said Member in addition to or different from the forms of such taxes now being levied or assessed against said Member, or there should be any increase or decrease in the rate of such existing or future taxes, and such taxes or changes in such taxes should result in increasing or decreasing the cost to said Member in carrying out the provisions of this agreement, then in such event adjustments shall be made in the rates and charges for electric power and energy furnished hereunder to make allowance for such taxes and changes in such taxes in an equitable manner.

ARTICLE 11

BILLINGS AND PAYMENTS

11.1 All bills for amounts owed hereunder shall be due and payable on the twentieth day of the month next following the monthly or other period to which such bills are applicable, or on the fifteenth day following receipt of bill, whichever date be later. Interest on unpaid amounts shall accrue at the rate of six percent per annum from the date due until the date upon which payment is made. Unless otherwise agreed upon a calendar month shall be the standard monthly period for the purpose of settlements under this agreement.

ARTICLE 12

MODIFICATION

12.1 Any Member, by written notice given to the other Members and Agent not less than ninety days prior to the beginning of any calendar year of the duration of this agreement, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, there shall be taken into account any changed conditions, any results from the application of said terms and conditions, and any other factors that might cause said terms and conditions to result in an inequitable division of the benefits of interconnected operation or in an inadequate realization of such benefits. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of January of the calendar year next following the aforesaid ninety-day notice period.

ARTICLE 13

DURATION OF AGREEMENT

13.1 This agreement shall become effective August 1, 1951, and shall continue in effect for an initial period expiring December 31, 1971, and thereafter for successive periods of one year each until terminated as provided under subdivision 13.2 below.

13.2 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE 14

TERMINATION OF EXISTING AGREEMENTS

14.1 Upon their joint execution of this agreement Appalachian Company and Ohio Company agree that the inter-connection agreements between them dated November 28, 1930, and September 1, 1936, respectively, and all supplements and amendments thereto, shall terminate as of July 31, 1951, and that all further obligations between them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

14.2 Upon their joint execution of this agreement Indiana Company and Ohio Company agree that the interconnection agreements between them, dated October 15, 1930, and September 1, 1936, respectively, and all supplements and amendments thereto, shall terminate as of July 31, 1951, and that all further obligations between them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

ARTICLE 15

REGULATORY AUTHORITIES

15.1 This agreement is made subject to the jurisdiction of any governmental authority or authorities having lawful jurisdiction in the premises.

ARTICLE 16

ASSIGNMENT

16.1 This agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

16.2 IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto duly authorized as of the day and year first above written.

(The numerous pages of the various signatories to the original Agreement and subsequent modifications thereto, are omitted herein.)

Kentucky Power Company

REQUEST

Please provide a copy of the Notice of Termination of the AEP Interconnection Agreement. Please provide the docket(s) and jurisdictions in which AEP has sought authorization, if any, and provide a copy of the application in each such docket.

RESPONSE

Please see the Company's response to KPSC 1-1 for the notice of termination.

The Company has not made any applications seeking authorization for termination of the AEP Interconnection Agreement at this time.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please describe the present status of the AEP Interconnection Agreement, the Notice of Termination, and the development of any and all successor agreements in general and by jurisdiction.

RESPONSE

Please see the Company's response to KPSC 1-1 and KPSC 1-2.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to subdivision 6.212 of the AEP Interconnection Agreement. Please provide the computation of the 1.37% monthly carrying charge factor, including separately, the derivation of the depreciation rate, the cost of capital by component, and income tax effects.

RESPONSE

As originally filed by KPCo and other affiliates in FERC Docket No. E-9408, the following cost components were identified on an annual basis:

Cost of money	11.50%
Depreciation	1.34
Income taxes	4.31
Other taxes, insurance and general administrative	2.00
Total	19.15%

However, KPCo and other affiliates proposed a reduced total annual charge of 17.5% in that filing.

In FERC's subsequent Orders in that proceeding dated July 27, 1979 and September 24, 1979, the FERC reduced the proposal to a total annual rate of 16.49%.

The FERC-approved annual rate of 16.49% is then divided by 12 to arrive at a montly rate of 1.37% when rounded to two decimal places.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a copy of the most recent version of the AEGC/KPC Rockport Unit Power Agreement.

a. For each month beginning September, 2010 to the present, please provide the monthly payment invoices to Kentucky Power for Rockport energy and capacity.

b. For each month beginning September, 2010 to the present, please provide the monthly AEP East Interchange Power statements and related data.

c. With respect to the scrubber projects announced for the Rockport plant, please provide the following information:

1. The expected capital cost of the scrubber at each unit;
2. When construction is expected to start; and
3. The projected rate increase to Kentucky Power for each month during construction and for the first full year of commercial operation.

RESPONSE

a. Please see Attachment 1 for the monthly invoices to KPCo for Rockport energy and capacity.

b. Please see Attachment 2 for the monthly AEP East Interchange Power statements. September 2010 through November 2011 are actuals files. December 2011 is estimated. The actuals are not available for December.

c. The Company objects to this Request as seeking information that is irrelevant and not likely to lead to the discovery of admissible evidence. The Company is not asking for recovery in this proceeding of any of the costs associated with the "Rockport Scrubber Project."

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a copy of the Company's most recent Integrated Resource Plan.

RESPONSE

Please see the response to Sierra Club 1-3.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 17 lines 1-4 of Mr. Wohnhas' Direct Testimony wherein he states that "For 2012, the Company has forecasted it will consume $6.2 million in CSAPR emission allowances" and "also is currently forecasting to have a gain of $650,000 in 2012 associated with the sale of annual NOx allowances under the CSAPR." On Exhibits LPM-13 and LPM-14, the Company calculated and included in the ECR revenue requirement for 2012 only the carrying costs on $6.2 million of CSAPR emission allowances in inventory, net of estimated NOx gains. The Company did not reflect any CSAPR emission allowance consumption expense or gains from the sale of allowances.

a. Please provide all support for the $6.2 million and $650,000 amounts cited by Mr. Wohnhas.

b. Please describe the basis for treating the annual consumption expense and gains as inventory items on Exhibit LPM-13.

c Please identify where the annual consumption expense and gains are reflected in the revenue requirement on Exhibit LPM-14.

d. Was treating the annual consumption expense and gains as inventory items on Exhibit LPM-13 an error? If so, provide corrected versions of all exhibits that are affected. If not, then please reconcile Mr. Wohnhas' testimony on these two issues with Ms. Munsey's treatment on her Exhibits LPM-13 and LPM-14.

RESPONSE

a. Please see the response to KPSC 1-93.

b-d. Exhibit LPM-13 as filed was incorrect. A corrected LPM-13 is filed as a response to KPSC 1-20. The annual consumption expenses and gains on inventory as well as a return on rate base for inventory allowances and consumption expense should have been included in the original Exhibit LPM-13. Attached as Exhibit 1 is the support for the estimated inventory levels.

WITNESS: Ranie K Wohnhas

KPCo Emission Allowance Inventory Forecast (000)

		Beginning Inventory												End Inv.	Monthly
		Jan-12	Feb-12	Mar-12	Apr-12	May-12	Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	2012	Avg. Inv.
SO2 - CSAPR	KPCo-KY	$ -	$ -	$ -	$ -	$ -	$ -	$ 597	$ 187	$ 227	$ 445	$ 281	$ 960	$ 286	425.976
CSAPR NOx	KPCo	$ 3	$ 3	$ 3	$ 3	$ 3	$ 3	$ 2	$ 2	$ 1	$ 1	$ 1	$ 1	$ 1	2.053
CSAPR Ann NOx	KPCo	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Note 1 - SO2 Monthly Avg. Inventory was calculated on a 7 month average to give the annual effect needed for the impact to customers.

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-1 and the $15.212 million for Preliminary Scrubber Analysis 2004-2006.

a. Please provide a copy of all authorities relied on for the deferral of these costs, including a copy of all requests to the Commission for authorization to defer these costs and any orders from the Commission authorizing the deferrals.

b. Please provide a copy of all analyses from the approximate time period of the deferrals, including any written communications through memoranda, emails or other forms, addressing the accounting for these costs and/or whether they should be expensed or deferred.

c. Please explain why the Company has not previously sought recovery of these deferrals either in base rate proceedings or ECR proceedings.

d. Please provide a schedule showing the costs that were deferred by month, by major activity, by FERC expense account (if the costs had not been deferred), and the FERC balance sheet account used for the deferrals.

RESPONSE

a. The Company made no filings with the Commission. Because the project had not reached the stage requiring application for a certificate of public convenience and necessity the Company did not make a filing when the costs were moved from Account 107 to Account 183.

b. The Company has no such analyses.

c. The Company continued to evaluate the disposition of the Big Sandy units in light of the Consent Decree and the various EPA regulations affecting Big Sandy. Until a final decision was made (as being proposed in this application) the Company did not believe it prudent to seek recovery from its customers.

d. Please refer to the Company's response to KPSC 1-18.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 22, line 18 through page 23 line 18 of Ms. Munsey's Direct Testimony. If the Company's quantification of the percentage rate increase is corrected for a) the error in the calculation of the Big Sandy 2 DFGD ADIT, which excluded the effects of accelerated tax depreciation, b) the error in using an entire year of accumulated depreciation and ADIT to reduce the initial revenue requirement impact of the Big Sandy 2 DFGD, and c) the error in treating allowance consumption expense and gains from sales as inventory rate base items rather than net expense items, please confirm that the percentage increase will be greater than the 31.4% cited by the Company in its legal notice and in its Application.

a. If the Company's calculation was in error, what steps will the Company take to modify its legal notice and to amend its Application, if any?

b. If the Company takes steps to modify its legal notice and amend its Application, what effect will these steps have on the procedural schedule in this proceeding, if any?

c. Please provide the corrected percentage rate increases in each year 2012 through 2016. Provide corrected exhibits and all workpapers and computations, including electronic spreadsheets with formulas intact.

RESPONSE

The Company cannot make the requested confirmation.

a-b. N/A. The Company's calculation was not in error.

c. Please refer to the Company's response to KPSC 1-20 and AG 1-28.

	2012	2013	2014	2015	2016
Jurisdictional Annual Revenue Increase	$4,976,129	$26,883	$0	$0	$162,993,233
Percent Increase	0.87%	0.01%	0.00%	0.00%	28.61%
Monthly Bill Effect with 1,000 kWh usage	$0.85	$0.01	$0.00	$0.00	$28.02

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Refer to Exhibit LPM-2.

a. Please explain why the retail revenue requirement includes the amount derived in column 4 "Capital Costs of Associated Utilities Revenues."

b. Please indicate whether the Commission previously has adopted the methodology reflected in column 4 and included this component of the total Company revenue requirement in the retail revenue requirement and ECR factor? If so, please provide a copy of the order(s) and all other relevant source documents demonstrating that the Commission has adopted the methodology.

c. Please confirm that the Commission has not previously adopted this methodology for Louisville Gas and Electric Company or for Kentucky Utilities Company, which also have sales to each other. Provide a copy of all research performed by or on behalf of the Company to determine the Commission precedent on this issue. If none, please explain why the Company did not research this issue.

d. Refer to page 10 lines 5-13 of Ms. Munsey's Direct Testimony wherein she states that the Company is proposing to use the "same methodology" authorized by the Commission in Case Nos. 2000-00107 and 2010-00318, and filed by the Company in Case No. 2011-00031. If the Company believes that this testimony is correct with respect to including an allocation of the sales to associated utilities in the retail jurisdictional, then please demonstrate that the "same methodology" was used in each of the cases cited by Ms. Munsey. Provide relevant pages of Commission orders, copies of pages from the Company Applications, copies of pages from the Company's filings and all other documents that the Company believes demonstrate that the "same methodology" was used.

RESPONSE

a-d. Please see response to KPSC 1-20.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please provide a two year history of the Company's monthly average daily balances of each type of short-term debt and the cost of that short-term debt in a format similar to that of the schedule provided in response to Staff First Set Item 16 in Case No. 2011-00031.

RESPONSE

Please see attachment to KIUC 1-6 response.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a two year history of the Company's monthly average daily balances of short-term investments, including amounts on deposit and loaned to other AEP companies through the utility money pool, and the return on those investments in a format similar to that of the short term debt schedule provided in response to Staff First Set Item 16 in Case No. 2011-00031.

RESPONSE

Please see attachment to KIUC 1-6 response.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Exhibit RLW-1. Please provide a more detailed timeline for Phase IIa and Phase IIb, showing all major activities in each phase.

RESPONSE

A more detailed timeline for Phase IIa and Phase IIb specific to the Big Sandy DFGD project is being developed as part of the activities under Phase I.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Refer to page 23 lines 18-21 of Mr. Walton's Direct Testimony.

a. Please provide a copy of the Consent Decree.

b. Please explain how the completion of the proposed Big Sandy 2 DFGD and tie-in by the end of the second quarter of 2016 complies with the requirement "to retrofit a FGD on Big Sandy Unit 2 by December 31, 2015."

RESPONSE

a. Please refer to the response provided by the Company in the Kentucky Commission Staff's First Request for Information, No. 3(b).

b. Please see KPCo's response to Staff 1-41.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that support, source, and/or otherwise address the assumptions used in the analyses presented by Mr. Weaver in his Direct Testimony. This includes, but is not limited to, any alternative assumptions that were considered but not used in the analyses.

RESPONSE

Please see KPSC 1-48 and the attachments to this response. Confidential protection is being sought for attachments 2 and 3.

WITNESS: Scott C Weaver

BS1 Repower Cost Estimates - Preliminary *

Cost in MM 2011 USD	Opt 1 - 2x2 MHI 501GAC		Opt 2 - 2x2 GE 7FA.05	
	745 MW Net Output (780 MW w/ Duct Firing)		602 MW Net Output	
NGCC EPC Subtotal (from S&L)	655.3	**	603.2	
AEP Owners Costs (per EP&FS)	56.7		53.7	
Total NGCC (2011 $)	712.0	913 $/kW	656.9	1,091 $/kW
Interconnections				
Natural Gas Supply (per FEL)	47.4		47.4	
Transmission/SWYD (per EP&FS)	6.5		6.5	
Total Interconn (2011 $)	53.9		53.9	
Project Total (2011 $)	765.9	982 $/kW	710.8	1,181 $/kW
S&L Escalation	62.2		58.0	
Project Total (As Spent)	828.1	1,062 $/kW	768.8	1,277 $/kW

* Costs exclude AFUDC, AEP Corp overhead allocations and AEP Contingency adder.
** Served as basis for Strategist modeling… Subsequently, S&L EPC est. slighted modified to $664.5M (+1.4%)

BS (Brownfield) NGCC Cost Estimates - Preliminary *

Cost in MM 2011 USD	Opt 2 - G Class		Opt 2 - F Class	
	762 MW Net Output (904 MW w/ Duct Firing)		606 MW Net Output	
NGCC EPC Subtotal (from S&L)	790.2	**	715.2	
AEP Owners Costs (per EP&FS)	53.8		50.5	
Total NGCC (2011 $)	844.0	934 $/kW	765.7	1,264 $/kW
Interconnections				
Natural Gas Supply (per FEL)	47.4		47.4	
Transmission/SWYD (per EP&FS)	4.4		4.4	
Total Interconn (2011 $)	51.8		51.8	
Project Total (2011 $)	895.8	991 $/kW	817.5	1,349 $/kW
S&L Escalation	73.2		67.2	
Project Total (As Spent)	969.0	1,072 $/kW	884.7	1,460 $/kW

* Costs exclude AFUDC, AEP Corp overhead allocations and AEP Contingency adder.
** Served as basis for Strategist modeling… Subsequently, S&L EPC est. slighted modified to $786.1M (<0.5%>)

BS1 Repower Cost Estimates - Preliminary

Cost in MM USD	**Opt 1 - MHI 501GAC**		**Opt 2 - GE 7FA.05**	
	745 MW Net Output (780 MW w/ Duct Firing)		*602 MW Net Output*	
NGCC EPC (per S&L Study)				
Equipment	295.4		258.9	
Material & Construction	177.8		170.5	
Constr Indirects	63.1		60.5	
Prof. Services & Spares	42.8		42.1	
Base Contingency	76.2		71.1	
Subtotal - EPC	**655.3** *		**603.2**	
AEP Owner's Cost Est.				
PME&C + Plant	38.8		35.8	
Startup/Comm	15.3		15.3	
BAR Insurance	2.6		2.6	
Total NGCC (2011 $)	**712.0**	*913 $/kW*	**656.9**	*1,091 $/kW*
Interconnections				
Natural Gas Supply	47.4		47.4	
Transmission/SWYD	6.5		6.5	
Total Intercon (2011 $)	**53.9**	*69 $/kW*	**53.9**	*90 $/kW*
Project Total (2011 $)	**765.9**	*982 $/kW*	**710.8**	*1,181 $/kW*
S&L-Assumed Escalation	62.2		58.0	
Project Total (As Spent)	**828.1**	*1,062 $/kW*	**768.8**	*1,277 $/kW*

Note: Above costs excluded AFUDC , Corp OH allocations and AEP contingency adder.

** Subsequently, slightly revised by S&L to $664.5M, (+1.4%)*

Brownfield CC Cost Estimates - Preliminary

Cost in MM USD	**Opt 2 - G Class** *762 MW Net Output (904 MW w/ Duct Firing)*			**Opt 2 - F Class** *606 MW Net Output*		
NGCC EPC (per S&L Study)						
Equipment	360.6			309.7		
Material & Construction	218.7			208.3		
Constr Indirects	79.8			75.4		
Prof. Services & Spares	43.2			42.2		
Base Contingency	87.9			79.6		
Subtotal - EPC	790.2 *			715.2		
AEP Owner's Cost Est.						
PME&C + Plant	35.9			32.6		
Startup/Comm	15.3			15.3		
BAR Insurance	2.6			2.6		
Total NGCC (2011 $)	**844.0**	*1,108*	*$/kW*	**765.7**	*1,264*	*$/kW*
Interconnections						
Natural Gas Supply	47.4			47.4		
Transmission/SWYD	4.4			4.4		
Total Intercon (2011 $)	**51.8**	*68*	*$/kW*	**51.8**	*86*	*$/kW*
Project Total (2011 $)	**895.8**	*1,176*	*$/kW*	**817.5**	*1,349*	*$/kW*
S&L-Assumed Escalation	73.2			67.2		
Project Total (As Spent)	**969.0**	*1,272*	*$/kW*	**884.7**	*1,460*	*$/kW*

Note: Above costs excluded AFUDC , Corp OH allocations and AEP contingency adder.

*** Subsequently, slightly revised by S&L to* ***<u>$786.1M, (<0.5%>)</u>***

Big Sandy Pipeline Information: ALL COSTS ARE ASSOCIATED WITH A ~600MW CC UNIT

Distance from plant/site	8.21 miles
Proposes lateral size (inches)	20"
Mainline Size (inches)	2 mainlines: 1 (24"), 1 (26"); Discharge of station 114; Mainline MAOP = 910#
Current pipeline pressure	Firm model - approx 875#; Historical average - 800#
Pressure & Volume (psi)	550 psig @ 4,200 mmBtu/hr
Infrastructure upgrades, including compression, required to support pressure and volume	utilize TGP mainline pressure
Indicative cost estimate for required infrastructure upgrades plus tax gross up (35%) (Pipeline to build and AEP to pay all cost up front)	$47.4MM
How will the capital investment be handled (AEP to pay up front, or long-term contract with pipeline)	Flexible: upfront capital subject to tax gross up or long term transportation contract
Mainline Compression type: gas or electric	Gas & Electric (redundant)
Is there backup (diesel) in place for compression?	no
Available supply for delivery point	100 mmsfcd forward haul. Ability to serve from Marcellus/Rex.
Operational Flexibility	High

TABLE 2

Estimated "Alternative" Capital Expenditures

Utilized in Strategist Modeling

(TOTAL Project Costs, Excluding AFUDC)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
(1)			EPC Cost		Add'l Owner's Cost/OH Alloc	TOTAL COST *(Excluding AFUDC)*		
(2)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed	
(3)	Option #1: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*	
(4)	RETROFIT Option							
(5)	**Dry (NID™) FGD**		$769	869	$70	$839	948	
(6)	*Plus: Add'l Costs included in Modeling*			(a)			(a)	(a) CCR-related (2011$ cost/kW)
(7)	*CCR-Related (thru 2017)*		$44	48	$4	$48	53	corrected from filed version of TABLE 2 (however, est. *dollar values* unchanged)
(8)	*TOTAL All Projects*	*800*	*$814*	*917*	*$74*	*$888*	*1,001*	
(9)		*Unit Capacity*						
(10)		*(w/ Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed	
(11)	Option #2: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*	
(12)	REPLACEMENT Option							
(13)	**New-Build CC** *(@ BS site)*	*904*	**$1,066**	**1,092**	**$75**	**$1,141**	**1,169**	
(14)		*Unit Capacity*						
(15)		*(w/ Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed	
(16)	Option #3: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*	
(17)	REPLACEMENT Option							
(18)	**BS1 CC Repowering**	*780*	**$994**	**1,180**	**$70**	**$1,063**	**1,263**	

DFGD and Alternative Project Cost Estimates

	2011	2012	2013	2014	2015	2016	2017	2018	TOTAL	Cost per kW Nominal ('As-Spent')$	Cost per kW 2011 $
Nominal k$											
Big Sandy 2 DFGD Retrofit											
BS000LDFL BS U0 FGD Landfill	2,280	3,347	7,853	17,014	21,495	10,568	143	0	62,700	$ 94	$ 86
BS001ASSC BS U2 FGD Assoc	0	4,000	12,000	18,000	36,000	102,100	0	0	172,100	$ 258	$ 229
BS001FGD0 Big Sandy U2 FGD	0	20,000	62,000	102,000	142,000	80,300	0	0	406,300	$ 609	$ 554
Total FGD Direct Costs	2,280	27,347	81,853	137,014	199,495	192,968	143	0	641,100	$ 962	$ 869
Contingency Adder @ 20% (Per EP&FS)	456	5,469	16,371	27,403	39,899	38,594	29	0	128,220		
Total FGD Direct -- Contingency-Adj.	2,736	32,816	98,224	164,417	239,394	231,562	172	0	769,320		
AEP Allocated Costs/OH (9.1%)	249	2,986	8,938	14,962	21,785	21,072	16	0	70,008		
GRAND TOTAL FGD	2,985	35,803	107,162	179,379	261,179	252,634	187	0	839,328		$ 948
CCR (only)											
000020353 BS U2 Bottom Ash Reline				0	889	4,121	4245		9,255		
000020356 BS U2 Ash WWT System			0	1,747	8,735	17,471	6,988	0	34,941		
TOTAL CCR Direct	0	0	0	1,747	9,624	21,592	11,233	0	44,196		
2011 k$	(Escalation Factor)		2.8%								
TOTAL Unit (Contingency-Adjusted)											
Big Sandy 2 DFGD Retrofit										Cost per kW	
BS000LDFL BS U0 FGD Landfill	*2,736*	*3,907*	*8,917*	*18,794*	*23,097*	*11,046*	*145*	*0*	68,642		
BS001ASSC BS U2 FGD Assoc	*0*	*4,669*	*13,626*	*19,883*	*38,682*	*106,719*	*0*	*0*	183,579		*2011$*
BS001FGD0 Big Sandy U2 FGD	*0*	*23,346*	*70,402*	*112,668*	*152,580*	*83,933*	*0*	*0*	442,930		
Total FGD Direct Costs	*2,736*	*31,923*	*92,946*	*151,345*	*214,359*	*201,698*	*145*	*0*	*695,151*		$ 869
CCR (only)											
000020353 BS U2 Bottom Ash Conversion	-	-	-	-	*796*	*3,590*	*3,597*	-	7,982		
000020356 BS U2 Ash WWT System	-	-	-	*1,608*	*7,822*	*15,218*	*5,921*	-	30,568		
TOTAL CCR Direct	*0*	*0*	*0*	*1,608*	*8,618*	*18,807*	*9,518*	*0*	*38,551*		$ 48
New-Build CC (Brownfield @ BS site)										Cost per kW Nominal ('As-Spent')$	Cost per kW '2011 $'/kW
Cash Flow	*0.5%*	*5.5%*	*30.0%*	*46.0%*	*15.0%*	*3.0%*			*100.0%*		
Assuming 2x1 Mitsubishi 501-GAC											
Contingency-Adjusted											
Nominal k$											
Project Estimate (Per S&L/Kiewet Study)	4,845	53,295	290,700	445,740	145,350	29,070	0	0	969,000		
Contingency Adder @ 10% (Per EP&FS)	485	5,330	29,070	44,574	14,535	2,907	0	0	96,900		
Total EPC	5,330	58,625	319,770	490,314	159,885	31,977	0	0	1,065,900	$ 1,179	
AEP Allocated Costs/OH (Increm 7.0%)	373	4,104	22,384	34,322	11,192	2,238	0	0	74,613	$ 83	
GRAND CC @ BS	5,703	62,728	342,154	524,636	171,077	34,215	0	0	1,140,513		
Total '2011 $' EPC	*5,330*	*57,028*	*302,588*	*451,331*	*143,164*	*27,853*	*0*	*0*	*987,293*		$ 1,092
Total '2011 $' OH	*373*	*3,992*	*21,181*	*31,593*	*10,022*	*1,950*	*0*	*0*	*69,111*		
Total '2011 $' TOTAL	*5,703*	*61,020*	*323,769*	*482,924*	*153,186*	*29,803*	*0*	*0*	*1,056,404*		*1,169*
(Big Sandy Unit 1) Repowered CC										Cost per kW Nominal ('As-Spent')$	Cost per kW '2011 $'/kW
Cash Flow	*0.5%*	*5.5%*	*30.0%*	*46.0%*	*15.0%*	*3.0%*			*100.0%*		
Assuming 2x1 Mitsubishi 501-GAC											
Contingency-Adjusted											
Nominal k$											
Project Estimate (Per S&L/Kiewet Study)	4,141	45,546	248,430	380,926	124,215	24,843	0	0	828,100		
Contingency Adder @ 20% (Per EP&FS)	828	9,109	49,686	76,185	24,843	4,969	0	0	165,620		
Total EPC	4,969	54,655	298,116	457,111	149,058	29,812	0	0	993,720	$ 1,274	
AEP Allocated Costs/OH (Increm 7.0%)	348	3,826	20,868	31,998	10,434	2,087	0	0	69,560	$ 89	
GRAND CC @ BS	5,316	58,480	318,984	489,109	159,492	31,898	0	0	1,063,280		
Total '2011 $' EPC	*4,969*	*53,166*	*282,097*	*420,768*	*133,470*	*25,967*	*0*	*0*	*920,436*		$ 1,180
Total '2011 $' OH	*348*	*3,722*	*19,747*	*29,454*	*9,343*	*1,818*	*0*	*0*	*64,431*		
Total '2011 $' TOTAL	*5,316*	*56,888*	*301,844*	*450,222*	*142,813*	*27,785*	*0*	*0*	*984,867*		*1,263*

Determination of (Unit-Specific) Relative Impacts on CC-Build Costs per $100MM Change in CPW

	Brownfield CC-Build				Repowered CC (BS1)		
2011 **Installed Cost**	1,169	/kW (excl. AFUDC)			1,262	/kW (excl. AFUDC)	
In-Svc Date	*2016*				*2016*		
As-Spent $	1,262	$/kW (excl. AFUDC)			1,363	$/kW (excl. AFUDC)	
AFUDC $	151	$/kW		0.12	164	$/kW	
TOTAL $	1,414	$/kW		-	1,526	$/kW	0
Carrying Charge	13.4%				13.4%		
WACC	8.58%				8.58%		
		1,141.00		-	1,063.00		
Replaced Unit		BS2			BS2		
		2x1 MHI-501GAC			2x1 MHI-GAC		
CC Size (MW)		904			780		
Annual Carrying Costs ($MM)		171.6			159.9		
CPW of Carrying Costs ($MM) (2011$)							
(2016 thru 2040 only)		1,141.59	*1141.58784*		1,064	*1,064*	

Therefore...

A +/- ___% change in CC-Build Costs ('As-Spent' TOTAL $) that would equate to a +/- $100 MM change in CPW

	Brownfield CC-Build	Repowered CC (BS1)
	8.76%	9.40%

Determination of (Unit-Specific) Relative Impacts on <u>RETROFIT</u> Build Costs per $100MM Change in CPW
("Retrofits" include: FGD only)

		BS2		
Installed Cost (2011 $)		948	/kW (excl. AFUDC)	
In-Svc Date (6/1)		*2016*		
As-Spent $	*1048.75*	1,049	$/kW (excl. AFUDC)	
AFUDC $	*126.25*	126	$/kW	
TOTAL $		**1,175**	$/kW	0
Carrying Charge (15-Year Recovery)		16.6%		
WACC		8.58%		
Unit Size (MW) Pre-Retrofit		800		
Annual Carrying Costs ($MM)		155.8		
CPW of Carrying Costs ($MM) (2011$)				
(6/2016 thru 2040 only)		994	*994.2717*	

Therefore...
A +/- ___% change in RETROFIT-Build Costs ('As-Spent' TOTAL $) that would equate to a <u>+/- $100 MM change</u> in CPW

10.06%

"Break-Even" CPW Differentials (Cost / <Savings> vs. CC Builds)
($Millions)

Relative CPW Economics (vs. Retrofit)	KPCo BS2 CC-Repl	KPCo BS1 Repower
Pricing Scenario		
"Higher Plausible Band"	437.1	458.1
"Fleet Transition" No Carbon	314.8	334 2
"Fleet Transition-CSAPR" (Base)	236.4	252 3
"Fleet Transition" Early Carbon (2017)	180.4	190 3
"Lower Plausible Band"	176.8	182.8

"Multiple" per 100M of CPW Diff		
"Higher Plausible Band"	4.37	4.58
"Fleet Transition" No Carbon	3.15	3.34
"Fleet Transition-CSAPR" (Base)	2.36	2.52
"Fleet Transition" Early Carbon (2017)	1.80	1.90
"Lower Plausible Band"	1.77	1.83

CC Breakeven Cost (per kW)

% Change in CC Cost (Total 'As Spent')
that would Equal $100 MM CPW
(Assumes ALL OTHER Modeling Variables Remain Constant)

	8 76%	9.40%
x -1 =	*(Since the 'CPW Differential is a function of the Retrofit option)*	
Total Change Required to achieve Modeled CPW Differential *(Above)*		
"Higher Plausible Band"	-38.3%	-43.1%
"Fleet Transition" No Carbon	-27.6%	-31.4%
"Fleet Transition-CSAPR" (Base)	-20.7%	-23.7%
"Fleet Transition" Early Carbon (2017)	-15.8%	-17.9%
"Lower Plausible Band"	-15.5%	-17.2%

"BASE" CC Cost per kW *(Excluding AFUDC)*		
('As Spent' $)	$ 1,262	$ 1,363
('2011' $)	$ 1,169	$ 1,262

BREAK-EVEN CC-BUILD COST ('2011' $/kW) *(Excluding AFUDC)*		
"Higher Plausible Band"	$ 721	$ 718
"Fleet Transition" No Carbon	$ 847	$ 865
"Fleet Transition-CSAPR" (Base)	$ 927	$ 963
"Fleet Transition" Early Carbon (2017)	$ 1,063	$ 1,119
"Lower Plausible Band"	$ 1,067	$ 1,129

NECESSARY CHANGE to... (all else being equal)

	CC	BS1 Repwr
"Higher Band" (+2011$/kW)	$ (541)	$ (644)
+ $M ('As Spent')	(436.92)	(457.90)
"Fleet Transition" No Carbon (+2011$/kW)	$ (415)	$ (497)
+ $M ('As Spent')	(314.60)	(334.06)
"Fleet Transition-CSAPR" (Base) (+2011$/kW)	$ (335)	$ (400)
+ $M ('As Spent')	(236.30)	(252.17)
"Fleet Transition" Early Carbon (2017) (+2011/kV	$ (106)	$ (143)
+ $M ('As Spent')	(180.34)	(190 23)
"Lower Band" (+2011/kW)	$ (102)	$ (133)
+ $M ('As Spent')	(176.73)	(182.67)

"Break-Even" CPW Differentials (Cost / <Savings> vs. Retrofit)
($Millions)

Relative CPW Economics (vs. Retrofit)	KPCo BS2 CC-Repl	KPCo BS2 Repower
Pricing Scenario		
"Higher Band"	437.1	458.1
"Fleet Transition" No Carbon	314.8	334.2
"Fleet Transition-CSAPR" (Base)	236.4	252.3
"Fleet Transition" Early Carbon (2017)	180.4	190.3
"Lower Band"	176.8	182.8
"Multiple" per 100M of CPW Diff		
"Higher Band"	4.37	4.58
"Fleet Transition" No Carbon	3.15	3.34
"Fleet Transition-CSAPR" (Base)	2.36	2.52
"Fleet Transition" Early Carbon (2017)	1.80	1.90
"Lower Band"	1.77	1.83

RETROFIT Breakeven Cost (per kW)
("Retrofits" include: FGD only)
% Change in RETROFIT Cost (Total 'As Spent')
that would Equal $100 MM CPW
(Assumes ALL OTHER Modeling Variables Remain Constant)

	KPCo BS2 CC-Repl	KPCo BS2 Repower
% Change equal to $100 MM CPW	10.06%	10.06%

Total Change Required to achieve Modeled CPW Differential *(Above)*

	KPCo BS2 CC-Repl	KPCo BS2 Repower
"Higher Band"	**44.0%**	**46.1%**
"Fleet Transition" No Carbon	**31.7%**	**33.6%**
"Fleet Transition-CSAPR" (Base)	**23.8%**	**25.4%**
"Fleet Transition" Early Carbon (2017)	**18.1%**	**19.1%**
"Lower Band"	**17.8%**	**18.4%**

"BASE" (UNIT-SPECIFIC) RETROFIT Cost per kW
(Excluding AFUDC)

	KPCo BS2 CC-Repl	KPCo BS2 Repower
('As Spent' $)	$ 1,049	$ 1,049
('2011' $)	$ 948	948

BREAK-EVEN RETROFIT COST ('2011' $/kW)
(Excluding AFUDC)

	KPCo BS2 CC-Repl	KPCo BS2 Repower
"Higher Band"	**$ 1,365**	**$ 1,385**
"Fleet Transition" No Carbon	**$ 1,248**	**$ 1,267**
"Fleet Transition-CSAPR" (Base)	**$ 1,173**	**$ 1,189**
"Fleet Transition" Early Carbon (2017)	**$ 1,120**	**$ 1,129**
"Lower Band"	**$ 1,117**	**$ 1,122**

NECESSARY CHANGE to BS2 RETROFIT Cost (all else being equal)

	KPCo BS2 CC-Repl	KPCo BS2 Repower
"Higher Band" (+2011$/kW)	$ 417	$ 437
+ $M ('As Spent')	368.9	386.6
"Fleet Transition" No Carbon (+2011$/kW)	$ 300	$ 319
+ $M ('As Spent')	265.61	282.03
"Fleet Transition-CSAPR" (Base) (+2011$/kW)	$ 225	$ 241
+ $M ('As Spent')	199.50	212.90
"Fleet Transition" Early Carbon (2017) (+2011/kW)	$ 172	$ 181
+ $M ('As Spent')	152.25	160.60
"Lower Band" (+2011/kW)	$ 169	$ 174
+ $M ('As Spent')	149.21	154.22

KPC 2010 Customers

	Residential	Commercial	Industrial	Other Ultimate	Total Ultimate
KPC Total	142,971	29,790	713	391	173,865

KPC June YTD 2011 Customers

	Residential	Commercial	Industrial	Other Ultimate	Total Ultimate
KPC Total	142,350	29,909	708	413	173,380

KPC 2010 Sales (GWh)

	Residential	Commercial	Industrial	Other Ultimate	Total Ultimate	FERC	TOTAL
KPC Total	2,614	1,469	3,256	10	7,349	101	7,450
				% of sales to Retail Customers		98.6%	

KPC June 2011 YTD Sales (GWh)

	Residential	Commercial	Industrial	Other Ultimate	Total Ultimate	FERC	TOTAL
KPC Total	1,242	680	1,631	5	3,558	48	3,606
				% of sales to Retail Customers		98.7%	

KPC 2010-2011 Peak Demand (MW)

MoDate	Date	Hour	Peak
Jan-10	1/8/2010	9	1,543
Feb-10	2/1/2010	9	1,431
Mar-10	3/5/2010	8	1,348
Apr-10	4/28/2010	7	1,036
May-10	5/27/2010	15	1,110
Jun-10	6/15/2010	16	1,205
Jul-10	7/23/2010	16	1,245
Aug-10	8/4/2010	14	1,310
Sep-10	9/2/2010	16	1,191
Oct-10	10/22/2010	8	997
Nov-10	11/29/2010	8	1,208
Dec-10	12/15/2010	9	1,596
Jan-11	1/14/2011	9	1,445
Feb-11	2/11/2011	9	1,522
Mar-11	3/2/2011	8	1,171
Apr-11	4/1/2011	7	1,114
May-11	5/31/2011	14	1,208
Jun-11	6/8/2011	15	1,189

KPC All-Time Peaks

	Date	Hour	Peak
Summer	8/2/2006	15	1,388
Winter	2/6/2007	9	1,808

Big Sandy U2 On-Going Capex assumed in Strategist Modelling

		'Modelled' Ongoing Capital BS2 (Excl. DFGD & Related) ($000)	*Less:* CCR-Related	*'Net of CCR'* Ongoing Capital BS2 (Excl. DFGD & Related) ($000)
Per L/T Budget	2011	18,339		18,339
Per L/T Budget	2012	6,102		6,102
Per L/T Budget	2013	16,788	1,747	15,041
Per L/T Budget	2014	21,361	10,091	11,270
Per L/T Budget	2015	35,315	21,627	13,688
Per L/T Budget	2016	16,740	11,411	5,329
Per L/T Budget	2017	7,544	1,157	6,387
Per L/T Budget	2018	28,765		28,765
Per L/T Budget	2019	3,406		3,406
Per L/T Budget	2020	6,498		6,498
		16,086	Avg. Annual	*11,482*
Future Estimated	2021	13,346	*Used Prior (5-Year) Rolling Avg. + Inflator*	
Future Estimated	2022	12,627		
Future Estimated	2023	13,704		
Future Estimated	2024	10,511		
Future Estimated	2025	12,018		
Future Estimated	2026	13,188		
Future Estimated	2027	13,154		
Future Estimated	2028	13,266		
Future Estimated	2029	13,173		
Future Estimated	2030	13,737		
Future Estimated	2031	14,102		
Future Estimated	2032	14,295		
Future Estimated	2033	14,537		
Future Estimated	2034	14,807		
Future Estimated	2035	15,153		
Future Estimated	2036	15,454		
Future Estimated	2037	15,740		
Future Estimated	2038	16,047		
Future Estimated	2039	16,367		
Future Estimated	2040	16,697		
Avg. Annual (2021-2040)		*15,320*		
TOTAL Re-investment (All-Yrs) *(nominal $)*		458,866	/ 800 MW	$ 574 /kW

Sargent & Lundy, LLC

Estimate No.: 31118A
Project No.: 12721-001

AEP
Big Sandy Combined Cycle Brownfield Build Plant
Option 2 - BS Plant FGD Area
Conceptual Project Cost Estimate
Cost Estimate Summary

Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
10.00	GENERAL SITE WORK				
10.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, GENERAL SITE WORK	$ 1,357,500	$ 5,676,853	$ 8,530,324	$ 15,564,677

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11.00	UNDERGROUND				
11.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, UNDERGROUND	$ 270,375	$ 7,504,657	$ 22,215,963	$ 29,990,995

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21.00	CTG A				
21.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, CTG A	$ 72,203,250	$ 584,201	$ 6,927,195	$ 79,714,645

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
22.00	CTG B				
22.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, CTG B	$ 72,203,250	$ 584,201	$ 6,923,089	$ 79,710,540

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31.00	HRSG A				
31.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, HRSG A	$ 29,263,520	$ 1,062,987	$ 16,689,676	$ 47,016,183

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
32.00	HRSG B				
32.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, HRSG B	$ 29,149,120	$ 1,062,987	$ 16,667,514	$ 46,879,621

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
41.00	STEAM TURBINE				
41.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, STEAM TURBINE	$ 70,730,556	$ 1,172,926	$ 10,525,775	$ 82,429,256

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
50.00	COOLING TOWER				
50.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, COOLING TOWER	$ 11,139,950	$ 2,135,933	$ 4,233,801	$ 17,509,684

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
55.00	WATER TREATMENT				
55.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, WATER TREATMENT	$ 4,240,230	$ 2,337,720	$ 2,782,897	$ 9,360,847

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
56.00	PRE-TREATMENT				
56.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, PRE-TREATMENT	$ 11,702,868	$ 5,404,764	$ 6,168,527	$ 23,276,160

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
60.00	PIPE RACK				
60.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, PIPE RACK	$ -	$ 2,127,683	$ 2,170,928	$ 4,298,611

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
70.00	ELECTRICAL POWER DISTRIBUTION				
70.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, ELECTRICAL POWER DISTRIBUTION	$ 29,854,672	$ 8,517,597	$ 34,135,430	$ 72,507,699

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
75.00	DCS				
75.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, DCS	$ 5,809,860	$ 3,305,906	$ 9,784,731	$ 18,900,497

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
80.00	BOP				
80.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, BOP	$ 25,246,946	$ 20,542,876	$ 38,701,784	$ 84,491,605

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AEP
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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
90.00	COMMON				
90.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, COMMON	$ 6,218,500	$ 17,180,840	$ 20,213,517	$ 43,612,858

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Conceptual Project Cost Estimate
Cost Estimate Summary

Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
	OVERALL PROJECT SUBTOTALS				
OP.89	DIRECT COSTS	$ 339,120,341	$ 64,009,822	$ 146,562,493	$ 549,692,655
OP.90	CONSTRUCTION INDIRECTS	$ 8,826,256	$ 15,042,308	$ 55,058,659	$ 78,927,223
OP.99	SUBCONTRACTS	$ 21,444,000	$ 150,000	$ 5,050,000	$ 26,644,000
OP.00	SUBTOTAL PROJECT COSTS	$ 369,390,597	$ 79,202,130	$ 206,671,152	$ 655,263,878
PI.00	OVERALL PROJECT INDIRECT COSTS				$ 37,665,800
	Spare Parts				$ 5,540,800
	S&L Base Contingency				$ 87,601,700
	S&L Escalation				$ 66,704,367
	Subtotal Project Cost				$ 852,776,545
	Owner's Costs				$ -
	AFUDC (Interest During Construction)				$ -
	Total Project Cost				$ 852,776,545
	Total Project Cost 2011$ (Excl Owner's Cost, AFUDC, Escalation and AEP Contingency Adder)				$ 786,072,178

Sargent & Lundy, LLC

Estimate No.: 31238B
Project No.: 12756-002

AEP
Big Sandy Plant Unit 1 Repowering Cost Estimate Study
Option 1 - 2x2 MHI 501GAC Combustion Turbines
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Cost Estimate Summary

Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
10.00	GENERAL SITE WORK				
10.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, GENERAL SITE WORK	$ -	$ 6,295,277	$ 8,757,338	$ 15,052,615

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
11.00	UNDERGROUND				
11.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, UNDERGROUND	$ 112,875	$ 6,639,620	$ 17,778,264	$ 24,530,759

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
21.00	CTG A				
21.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, CTG A	$ 72,203,250	$ 584,201	$ 6,684,584	$ 79,472,035

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
22.00	CTG B				
22.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, CTG B	$ 72,203,250	$ 584,201	$ 6,679,721	$ 79,467,172

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
31.00	HRSG A				
31.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, HRSG A	$ 28,988,960	$ 1,062,987	$ 16,135,854	$ 46,187,800

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
32.00	HRSG B				
32.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, HRSG B	$ 28,874,560	$ 1,062,987	$ 16,115,880	$ 46,053,426

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
41.00	STEAM TURBINE				
41.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, STEAM TURBINE	$ 26,948,500	$ 185,250	$ 617,696	$ 27,751,446

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
50.00	COOLING TOWER				
50.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, COOLING TOWER	$ 11,934,000	$ -	$ 304,877	$ 12,238,877

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
55.00	WATER TREATMENT				
55.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, WATER TREATMENT	$ 3,336,480	$ 2,741,429	$ 2,737,197	$ 8,815,107

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
56.00	PRE-TREATMENT				
56.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, PRE-TREATMENT	$ 4,169,200	$ 4,400,709	$ 5,039,082	$ 13,608,992
60.00	PIPE RACK				
60.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, PIPE RACK	$ -	$ 4,142,659	$ 4,201,379	$ 8,344,038

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
70.00	ELECTRICAL POWER DISTRIBUTION				
70.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, ELECTRICAL POWER DISTRIBUTION	$ 23,791,540	$ 6,912,222	$ 25,067,372	$ 55,771,135
75.00	DCS				
75.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, DCS	$ 5,886,720	$ 1,897,651	$ 5,543,258	$ 13,327,629

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
80.00	BOP				
80.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, BOP	$ 22,987,650	$ 24,776,024	$ 39,425,141	$ 87,188,815

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Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
90.00	COMMON				
90.00	TOTAL DIRECT, CONSTRUCTION INDIRECT, AND SUBCONTRACT COSTS, COMMON	$ 6,083,000	$ 9,103,206	$ 11,721,794	$ 26,908,001

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Cost Estimate Summary

Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
	OVERALL PROJECT SUBTOTALS				
OP.89	DIRECT COSTS	$ 262,105,109	$ 56,873,217	$ 117,955,509	$ 436,933,835
OP.90	CONSTRUCTION INDIRECTS	$ 5,660,875	$ 13,365,206	$ 44,553,930	$ 63,580,011
OP.99	SUBCONTRACTS	$ 39,754,000	$ 150,000	$ 4,300,000	$ 44,204,000
OP.00	SUBTOTAL PROJECT COSTS	$ 307,519,985	$ 70,388,423	$ 166,809,438	$ 544,717,846
PI.00	OVERALL PROJECT INDIRECT COSTS				$ 38,334,200
	Spare Parts				$ 4,612,800
	Contingency				$ 76,810,500
	Escalation				$ 56,305,259
	Subtotal Project Cost				$ 720,780,605
	Owner's Costs				$ -
	AFUDC (Interest During Construction)				$ -
	Total Project Cost				$ 720,780,605

Sargent & Lundy, LLC

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Conceptual Project Cost Estimate
Cost Estimate Summary

Account No.	Item Description	Total Equipment Cost	Total Material Cost	Total Construction & Erection Cost	Total Projected Cost
	Total Project Cost 2011$ (Excl Owner's Cost, AFUDC, Escalation and AEP Contingency Adder)				$ 664,475,346

Big Sandy Unit 2 DFGD Project Spend

Estimated AFUDC Calculation Utilized in Alternative Economic Evaluations (i.e., Initially Assuming No CWIP Treatment)

All Dollars in Millions

	Total Project Cost 'As Spent' $ (Excl. AFUDC)		*Year 1* 2011	*Year 2* 2012	*Year 3* 2013	*Year 4* 2014	*Year 5* 2015	*Year 6*** 2016	TOTAL	
DFGD *	1,046	Cash Cost + Overhead Alloc	3	36	107	179	261	253	*839*	
		Annual CF %	*0.4%*	*4.3%*	*12.8%*	*21.4%*	*31.1%*	*30.1%*	*100%*	
		(Avg) AFUDC Rate	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*	*8.6%*		
		AFUDC	0	2	8	21	42	28	101	Used For Comparative Modeling Purposes Only
		Total w/ AFUDC	3.11	38	115	200	303	281	940	

* includes DFGD, Associated (Boiler) Projects, FGD Landfill
** assumes 6/2016 In-service

BS2 FGD tech Inputs Summary Rev 0.1 2011-08-22.xls - CPCN View (+20% cont adder)

Nomenclature			Capital Cost Summary										O&M Summary					Key				
ID	Fuel	Cost Estimate	AEP										Fixed O&M	SO2 Cost	Other Var	Net Aux Load	SO2 Rem	Conditional Items				
	lb/ MMBtu		Total FGD	Assoc Proj	Haul Road	Landfill	Sunk Cost	Control Total	AEP Alloc	Total Capital w/o AFUDC	Add'l Capital	Rmvl		$/ton	$/MW-hrs*	MW	Eff(%)	Phase 2	Burners BMODs	Fuel Blend	ESP	Booster Fan
1	4.5	Wet Base AEP-1B	727.3	222.1	25.5	49.7	1.5	1,026.0	92.8	1,118.8	65.2	1.860	$5,853,000	$81.45	$0.11	23	98.0	N/A				REM
2	1.7	Wet AEP-2A	705.5	86.2	25.5	49.7	1.5	868.2	78.5	946.8	65.2	1.860	$5,268,000	$86.03	$0.17	18	97.7	N/A	N/A	N/A		REM
3	3	Wet AEP-3A	719.9	222.1	25.5	49.7	1.5	1,018.6	92.2	1,110.7	65.2	1.860	$5,565,000	$82.61	$0.14	21	98.0	N/A				REM
5	3	Dry (ESP) Base AEP-1A	554.8	222.1	25.5	49.7	1.5	853.5	77.2	930.7	65.2	1.749	$4,392,000	$318.19	$0.57	13	95.0	N/A				
6	1.7	Dry (ESP) AEP-2A	526.8	86.2	25.5	49.7	1.5	689.6	62.3	751.9	65.2	1.749	$4,292,000	$270.05	$0.57	12	95.0	N/A	N/A	N/A		
7	3	Dry (N/ESP) Base AEP-1B	554.8	206.5	25.5	49.7	1.5	837.9	75.8	913.6	-	2.693	$4,392,000	$296.10	$0.59	9	95.0	N/A			REM	REM
8	1.7	Dry (N/ESP) AEP-2B	526.8	70.5	25.5	49.7	1.5	673.9	60.9	734.8	-	2.693	$4,292,000	$293.84	$0.59	8	95.0	N/A	N/A	N/A	REM	REM
17	3	NID (ESP) Base AEP-1A	487.6	222.1	25.5	49.7	1.5	786.3	71.1	857.4	65.2	1.749	$4,956,000	$274.67	$0.58	15	98.0	N/A				
18	1.7	NID (ESP) AEP-2A	460.4	86.2	25.5	49.7	1.5	623.2	56.3	679.6	65.2	1.749	$4,846,000	$272.02	$0.58	14	97.7	N/A	N/A	N/A		
19	4.5	NID (ESP) AEP-3A	487.6	222.1	25.5	49.7	1.5	786.3	71.1	857.4	65.2	1.749	$5,066,000	$282.46	$0.58	16	98.0	N/A				
21	3	NID (N/ESP) Base AEP-1B	487.6	206.5	25.5	49.7	1.5	770.7	69.7	840.3	-	2.693	$4,956,000	$299.62	$0.59	11	98.0	N/A			REM	REM
22	1.7	NID (N/ESP) AEP-2B	460.4	70.5	25.5	49.7	1.5	607.6	54.9	662.5	-	2.693	$4,846,000	$328.06	$0.60	10	97.7	N/A	N/A	N/A	REM	REM
23	4.5	NID (N/ESP) AEP-3B	487.6	206.5	25.5	49.7	1.5	770.7	69.7	840.3	-	2.693	$5,066,000	$298.04	$0.60	12	98.0	N/A			REM	REM
28	4.5	CDS+FF (N/ESP)	554.4	206.5	25.5	49.7	1.5	837.5	75.7	913.2	-	2.693	$5,066,000	$299.74	$0.60	16	98.0	N/A			REM	REM

Notes:

1. MW-hrs based on 800 MW, 8760 hrs per year, 85% capacity factor.
2. SO2 Variable O&M cost based on FGD reagent and disposal cost
3. All capital costs escalated to time of performance
4. All O&M costs in 2010 $'s

Change Control

Rev 0 - Original Issue
Rev 1 - Added SO2 Removal Efficiency (%) column JEZ
Rev 2 - Updated IAQCS N/ESP 4.5 EST-1B Fixed O&M Dollars JEZ
Rev 3 - Revised format and added summary columns
Rev 4 - Updated and corrected data per team review 10.11.10
Rev 5 - Corrected Case 10 + 14 to AP, move escalation and cont to AP, added Phase 1 only cases and incorporated regulatory view
Rev 6 - Corrected Case 7, 16, 17 & 19, added Phase 2 cases
Rev 7 - Corrected S&L math on Case 3 + 11
Rev 8 - Corrected SO2 tons removed to match S&L mass balance (Column X)
Rev 9 - Corrected Case 6 owner costs and adjusted cashflow for P1 & P2 below the line cases 10,11,14&15 to reconcile differences in escalation & AFUDC
Rev 10 - Revised regulatory view to updated O&M categories
Rev 11 - Corrected regulatory view O&M data input errors
Rev 12 - Adjusted capital cost estimates and added new no wet ESP cases per PM direction
Rev 13 - Added Case 28 (CDS+FF). Beginning with Case 23, revised FGD cost based on input from PM; and revised O&M cost and other factors based on input from FGD Engineering.

Exhibit SCW-1A

Projected (Summer) Peak Demand and Internal Load
KPCo and AEP-East
(Sep-2011 Fcst)

	Peak Demand (MW)			Internal Load (GWh)	
Year	KPCo	AEP-East*	Year	KPCo	AEP-East*
2011	**1,221**	20,698	2011	**7,667**	125,470
2012	**1,238**	21,075	2012	**7,729**	127,318
2013	**1,239**	21,351	2013	**7,727**	128,689
2014	**1,243**	21,515	2014	**7,752**	129,445
2015	**1,247**	21,644	2015	**7,772**	129,976
2016	**1,252**	21,711	2016	**7,806**	130,552
2017	**1,256**	21,853	2017	**7,842**	131,173
2018	**1,271**	22,006	2018	**7,883**	131,944
2019	**1,281**	22,163	2019	**7,926**	132,798
2020	**1,287**	22,273	2020	**7,967**	133,593
2021	**1,299**	22,500	2021	**8,013**	134,489
2022	**1,309**	22,672	2022	**8,062**	135,372
2023	**1,313**	22,815	2023	**8,113**	136,258
2024	**1,320**	22,944	2024	**8,168**	137,223
2025	**1,333**	23,186	2025	**8,216**	138,146
2026	**1,344**	23,374	2026	**8,267**	139,105
2027	**1,354**	23,569	2027	**8,319**	140,108
2028	**1,362**	23,721	2028	**8,373**	141,157
2029	**1,369**	23,933	2029	**8,419**	142,128
2030	**1,379**	24,135	2030	**8,470**	143,160

	KPCo	AEP-East*
10-Year (2011-2020):		
Total Growth	**66**	1,575
Compound Annual Growth Rate	**0.59%**	0.82%
20-Year (2011-2030):		
Total Growth	**157**	3,437
Compound Annual Growth Rate	**0.64%**	0.81%

	KPCo	AEP-East*
10-Year (2011-2020):		
Total Growth	**301**	8,123
Compound Annual Growth Rate	**0.43%**	0.70%
2011-2030.		
Total Growth	**803**	17,690
Compound Annual Growth Rate	**0.53%**	0.70%

Exhibit SCW-1B

Projected Demand Response (DR) and Energy Efficiency (EE)
KPCo and AEP-East
(Sep-2011 Fcst)

	(CURRENT) PJM-APPROVED INTERRUPTIBLE DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "ACTIVE" DEMAND RESPONSE Peak Reduction (MW)		+ (PROJECTED) "PASSIVE" DEMAND RESPONSE Peak Reduction (MW)		= TOTAL DEMAND RESPONSE Peak Reduction (MW)	
Year	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East	KPCo	AEP-East
2011	0	445	2	47	2	76	4	568
2012	0	445	4	50	4	149	8	644
2013	0	445	4	50	7	252	10	747
2014	0	445	11	180	9	390	19	1,015
2015	0	445	18	300	10	523	28	1,268
2016	0	445	26	450	15	650	41	1,545
2017	0	445	35	600	18	765	53	1,811
2018	0	445	36	612	20	866	56	1,923
2019	0	445	36	624	21	993	58	2,063
2020	0	445	37	637	23	1,128	60	2,210
2021	0	445	38	649	23	1,221	61	2,315
2022	0	445	39	662	24	1,293	62	2,401
2023	0	445	39	676	23	1,350	63	2,471
2024	0	445	40	689	23	1,391	64	2,525
2025	0	445	41	703	23	1,427	64	2,575
2026	0	445	41	703	23	1,439	64	2,587
2027	0	445	41	703	23	1,439	64	2,587
2028	0	445	41	703	24	1,437	65	2,585
2029	0	445	41	703	23	1,439	64	2,587
2030	0	445	41	703	23	1,439	64	2,587

	(PROJECTED) CUMULATIVE ENERGY EFFICIENCY (GWh)	
Year	KPCo	AEP-East
2011	13	611
2012	31	988
2013	47	1,467
2014	60	2,232
2015	70	2,968
2016	95	3,699
2017	113	4,351
2018	122	4,927
2019	130	5,651
2020	136	6,419
2021	137	6,920
2022	138	7,325
2023	138	7,651
2024	137	7,904
2025	136	8,095
2026	135	8,162
2027	135	8,162
2028	135	8,162
2029	135	8,162
2030	135	8,162

DEMAND & ENERGY

PJM	Monthly Peak Demand (MW)			
Year	KPCo (PJM)	KPCo (Internal)	AEP-East (PJM)	AEP-East (Internal)
2011	1.218	1.236	20.515	20,809
2012	1.253	1.243	21 008	21.074
2013	1.283	1 259	21.510	21 294
2014	1,300	1,264	21,882	21,560
2015		1.268		21.709
2016		1.272		21.827
2017		1 276		22.013
2018		1,283		22.194
2019		1.291		22.396
2020		1,295		22.560
2021		1,310		22.822
2022		1,321		23.022
2023		1.327		23 166
2024		1.334		23,324
2025		1.347		23 573
2026		1,357		23 763
2027		1 367		23.963
2028		1 375		24.129
2029		1,385		24 354
2030		1,396		24,573
2011		1.236		20.809
2030		1,396		24,573
Total Growth		159		3,764
Compound Growth Rate		0.64%		0.88%

PJM (AEP-Traditional)	Annual Energy (GWh)	
Year	KPCo	AEP-East
2011	7.769	125.876
2012	7 840	128.105
2013	7.921	129,628
2014	7 935	130.287
2015	7.943	130,858
2016	7.973	131.584
2017	7 994	132.272
2018	8,021	133,034
2019	8,055	133.912
2020	8 100	134,867
2021	8.155	135 924
2022	8.214	136,890
2023	8 271	137.789
2024	8.322	138,678
2025	8 376	139 569
2026	8,428	140.460
2027	8,485	141,438
2028	8.545	142,501
2029	8 598	143,476
2030	8,657	144,538
2011	7,769	125,876
2030	8,657	144,538
Total Growth	888	18,662
Compound Growth Rate	0.57%	0.73%

ACTIVE DSM (DR)

Interruptible Demand Response	Monthly Peak (MW)		Annual Energy (GWh)	
Year	KPCo	AEP-East	KPCo	AEP-East
2011	0	445		
2012	0	445		
2013	0	445		
2014	0	445		
2015	0	445		
2016	0	445		
2017	0	445		
2018	0	445		
2019	0	445		
2020	0	445		
2021	0	445		
2022	0	445		
2023	0	445		
2024	0	445		
2025	0	445		
2026	0	445		
2027	0	445		
2028	0	445		
2029	0	445		
2030	0	445		

Active Demand Response	Monthly Peak (MW)	
Year	KPCo	AEP-East
2011	2	47
2012	4	50
2013	4	50
2014	11	100
2015	18	300
2016	26	450
2017	35	600
2018	36	612
2019	36	624
2020	37	637
2021	38	649
2022	39	662
2023	39	676
2024	40	689
2025	41	703
2026	41	703
2027	41	703
2028	41	703
2029	41	703
2030	41	703

Active + Interruptible Demand Response	Monthly Peak (MW)	
Year	KPCo	AEP-East
2011	2	492
2012	4	495
2013	4	495
2014	11	625
2015	18	745
2016	26	895
2017	35	1 045
2018	36	1,057
2019	36	1,070
2020	37	1,082
2021	38	1,095
2022	39	1 108
2023	39	1 121
2024	40	1 134
2025	41	1 148
2026	41	1.148
2027	41	1 148
2028	41	1 148
2029	41	1 148
2030	41	1,148

PASSIVE DSM (EE)

Forecasted EE	Monthly Peak (MW)		Annual Energy (GWh)	
Year	KPCo	AEP-East	KPCo	AEP-East
2011	2	76	13	611
2012	4	149	31	988
2013	7	252	47	1,457
2014	9	390	60	2,232
2015	10	523	70	2,958
2016	15	650	95	3,699
2017	18	765	113	4,351
2018	20	866	122	4,927
2019	21	993	130	5,651
2020	23	1,128	136	6,419
2021	23	1,221	137	6,920
2022	24	1,293	138	7,325
2023	23	1,350	136	7,651
2024	23	1,391	137	7,904
2025	23	1,427	135	8,095
2026	23	1,439	135	8,162
2027	23	1,439	135	8,162
2028	24	1,437	135	8,162
2029	23	1,439	135	8,162
2030	23	1,439	135	8,162

RPM Bid Amount	Monthly Peak (MW)	
Year	KPCo	AEP-East
2011	1	57
2012	3	112
2013	5	189
2014	5	235
2015	5	280
2016	6	299
2017	7	281
2018	7	258
2019	5	257
2020	3	272
2021	3	266
2022	2	225
2023	0	166
2024	0	128
2025	0	100
2026	0	67
2027	0	36
2028	0	7
2029	0	0
2030	0	0

Delayed Demand Forecast Impact	Monthly Peak (MW)	
Year	KPCo	AEP-East
2011	0	0
2012	0	0
2013	0	0
2014	2	76
2015	4	149
2016	7	252
2017	9	390
2018	10	523
2019	15	650
2020	18	765
2021	20	866
2022	21	993
2023	23	1 128
2024	23	1,221
2025	24	1 293
2026	23	1,350
2027	23	1 391
2028	23	1.427
2029	23	1.439
2030	23	1,439

(RPM Bid + Delayed Impact) - Forecasted	Monthly Peak (MW)	
Year	KPCo	AEP-East
2011	(0)	(19)
2012	(1)	(37)
2013	(2)	(63)
2014	(2)	(78)
2015	(2)	(93)
2016	(2)	(100)
2017	(2)	(94)
2018	(2)	(86)
2019	(2)	(85)
2020	(1)	(91)
2021	(1)	(89)
2022	(1)	(75)
2023	(0)	(55)
2024	0	(43)
2025	0	(33)
2026	0	(22)
2027	0	(12)
2028	(0)	(3)
2029	0	0
2030	(0)	(0)

DEMAND & ENERGY

PJM	Monthly Peak Demand (MW)			
Year	APCo (PJM)	APCo (Internal)	AEP-East (PJM)	AEP-East (Internal)
2011	5.931	6,052	20 515	20.809
2012	6,093	6,091	21 098	21,074
2013	6 247	6 156	21,610	21.394
2014	6,326	6.215	21,882	21,560
2015		6 281		21.709
2016		6.336		21,827
2017		6 392		22,013
2018		6,453		22.194
2019		6.518		22 396
2020		6.578		22 560
2021		6.671		22 823
2022		6.744		23.022
2023		6 787		23 186
2024		6.848		23.324
2025		6.935		23,573
2026		7,000		23 763
2027		7,073		23 963
2028		7.131		24 129
2029		7 199		24,354
2030		7,274		24,573
2011		6,052		20,809
2030		7.274		24,573
Total Growth		1,222		3,764
Compound Growth Rate		0.97%		0.88%

PJM (AEP-Traditional)	Annual Energy (GWh)	
Year	APCo	AEP-East
2011	37.566	125,876
2012	37,884	128 105
2013	38,077	129,628
2014	38 333	130.287
2015	38.624	130 858
2016	38.949	131.584
2017	39.192	132 272
2018	39,445	133.034
2019	39.732	133,912
2020	40,075	134,867
2021	40,470	135,924
2022	40,834	136,890
2023	41 191	137.789
2024	41 527	138.678
2025	41,877	139 569
2026	42.198	140 450
2027	42 564	141 438
2028	42 944	142 501
2029	43,293	143.476
2030	43,679	144,538
2011	37,566	125,876
2030	43,679	144,538
Total Growth	6,113	18,662
Compound Growth Rate	0.80%	0.73%

ACTIVE DSM (DR)

Interruptible Demand Response	Monthly Peak (MW)		Annual Energy (GWh)	
Year	APCo	AEP-East	APCo	AEP-East
2011	128	445		
2012	128	445		
2013	128	445		
2014	128	445		
2015	128	445		
2016	128	445		
2017	128	445		
2018	128	445		
2019	128	445		
2020	128	445		
2021	128	445		
2022	128	445		
2023	128	445		
2024	128	445		
2025	128	445		
2026	128	445		
2027	128	445		
2028	128	445		
2029	128	445		
2030	128	445		

Active Demand Response	Monthly Peak (MW)	
Year	APCo	AEP-East
2011	0	47
2012	0	50
2013	0	50
2014	56	160
2015	93	300
2016	139	450
2017	185	600
2018	189	612
2019	192	624
2020	196	637
2021	200	649
2022	204	662
2023	208	676
2024	213	689
2025	217	703
2026	217	703
2027	217	703
2028	217	703
2029	217	703
2030	217	703

Active + Interruptible Demand Response	Monthly Peak (MW)	
Year	APCo	AEP-East
2011	128	492
2012	128	495
2013	128	495
2014	183	625
2015	220	745
2016	265	895
2017	313	1.045
2018	316	1.057
2019	320	1.070
2020	324	1.082
2021	328	1.095
2022	332	1 108
2023	335	1 121
2024	340	1.134
2025	344	1.148
2026	344	1.148
2027	344	1.148
2028	344	1 148
2029	344	1 148
2030	344	1,148

PASSIVE DSM (EE)

Forecasted EE	Monthly Peak (MW)		Annual Energy (GWh)	
Year	APCo	AEP-East	APCo	AEP-East
2011	3	76	23	611
2012	10	149	79	988
2013	22	252	174	1.467
2014	33	390	255	2 232
2015	43	523	326	2.968
2016	64	650	459	3 699
2017	81	765	565	4 351
2018	93	866	641	4 927
2019	105	993	712	5,651
2020	115	1 128	778	6.419
2021	121	1 221	817	6 920
2022	127	1 293	852	7.325
2023	131	1.350	885	7,651
2024	136	1 391	916	7 904
2025	140	1.427	944	8,095
2026	140	1 439	944	8.162
2027	141	1 439	944	8 162
2028	140	1,437	944	8 162
2029	140	1,439	944	8.162
2030	140	1,439	944	8,162

RPM Bid Amount	Monthly Peak (MW)	
Year	APCo	AEP-East
2011	2	57
2012	8	112
2013	17	189
2014	23	235
2015	25	280
2016	32	299
2017	36	281
2018	37	258
2019	30	257
2020	25	272
2021	21	266
2022	17	225
2023	12	166
2024	11	128
2025	10	100
2026	7	67
2027	4	36
2028	0	7
2029	0	0
2030	0	0

Delayed Demand Forecast Impact	Monthly Peak (MW)	
Year	APCo	AEP-East
2011	0	0
2012	0	0
2013	0	0
2014	3	76
2015	10	149
2016	22	252
2017	33	390
2018	43	523
2019	64	650
2020	81	765
2021	93	866
2022	105	993
2023	115	1.128
2024	121	1.221
2025	127	1 293
2026	131	1 350
2027	135	1 391
2028	140	1,427
2029	140	1,439
2030	141	1,439

(RPM Bid + Delayed Impact) - Forecasted	Monthly Peak (MW)	
Year	APCo	AEP-East
2011	(1)	(19)
2012	(3)	(37)
2013	(6)	(63)
2014	(8)	(78)
2015	(6)	(93)
2016	(11)	(100)
2017	(12)	(94)
2018	(12)	(86)
2019	(10)	(85)
2020	(8)	(91)
2021	(7)	(69)
2022	(6)	(75)
2023	(4)	(55)
2024	(4)	(43)
2025	(3)	(33)
2026	(2)	(22)
2027	(1)	(12)
2028	0	(2)
2029	0	0
2030	0	(0)

DEMAND & ENERGY

PJM	Monthly Peak Demand (MW)			
Year	CSP (PJM)	CSP (Internal)	AEP-East (PJM)	AEP-East (Internal)
2011	4.153	4,250	20.515	20,809
2012	4 271	4 233	21,095	21,074
2013	4 374	4 298	21,610	21.394
2014	4,430	4,354	21,882	21,569
2015		4,396		21.709
2016		4,423		21,827
2017		4.467		22,013
2018		4.517		22.194
2019		4 574		22.396
2020		4,625		22 560
2021		4,681		22.623
2022		4.726		23,022
2023		4.764		23 186
2024		4,800		23.324
2025		4,852		23,573
2026		4,897		23 763
2027		4 940		23.963
2028		4 977		24 129
2029		5,027		24,354
2030		5,075		24,573
2011		4.250		20,809
2030		5,075		24,573
Total Growth		825		3,764
Compound Growth Rate		0.94%		0.88%

PJM (AEP-Traditional)	Annual Energy (GWh)	
Year	CSP	AEP-East
2011	22.881	125.876
2012	23,006	128.105
2013	23.331	129.628
2014	23,551	130.287
2015	23 710	130,858
2016	23,880	131.564
2017	24.034	132 272
2018	24 240	133.034
2019	24,473	133 912
2020	24 715	134.857
2021	24 935	135.924
2022	25,130	136,890
2023	25.261	137.789
2024	25,422	138,678
2025	25 555	139.569
2026	25 712	140.450
2027	25,874	141.438
2028	26,057	142.501
2029	26.204	143.476
2030	26,359	144,538
2011	22,881	125,876
2030	26,359	144,538
Total Growth	3,477	18,662
Compound Growth Rate	0.75%	0.73%

ACTIVE DSM (DR)

Interruptible Demand Response	Monthly Peak (MW)		Annual Energy (GWh)	
Year	CSP	AEP-East	CSP	AEP-East
2011	0	445		
2012	0	445		
2013	0	445		
2014	0	445		
2015	0	445		
2016	0	445		
2017	0	445		
2018	0	445		
2019	0	445		
2020	0	445		
2021	0	445		
2022	0	445		
2023	0	445		
2024	0	445		
2025	0	445		
2026	0	445		
2027	0	445		
2028	0	445		
2029	0	445		
2030	0	445		

Active Demand Response	Monthly Peak (MW)	
Year	CSP	AEP-East
2011	19	47
2012	19	50
2013	19	50
2014	38	180
2015	63	300
2016	94	450
2017	125	600
2018	128	612
2019	130	624
2020	133	637
2021	135	649
2022	138	662
2023	141	676
2024	144	689
2025	146	703
2026	146	703
2027	146	703
2028	146	703
2029	146	703
2030	146	703

Active + Interruptible Demand Response	Monthly Peak (MW)	
Year	CSP	AEP-East
2011	19	492
2012	19	495
2013	19	495
2014	38	625
2015	63	745
2016	94	895
2017	125	1,045
2018	128	1,057
2019	130	1,070
2020	133	1,082
2021	135	1,095
2022	138	1.108
2023	141	1.121
2024	144	1 134
2025	146	1 148
2026	146	1 148
2027	146	1 148
2028	146	1 148
2029	146	1.148
2030	146	1,148

PASSIVE DSM (EE)

Forecasted EE	Monthly Peak (MW)		Annual Energy (GWh)	
Year	CSP	AEP-East	CSP	AEP-East
2011	33	76	275	611
2012	56	149	364	988
2013	83	252	421	1,457
2014	121	390	614	2.232
2015	160	523	808	2 968
2016	193	650	977	3,699
2017	222	765	1 121	4 351
2018	247	866	1 245	4 927
2019	283	993	1 428	5 651
2020	331	1.128	1 678	6.419
2021	368	1.221	1 867	6 920
2022	397	1.293	2 014	7,325
2023	419	1.350	2.127	7,651
2024	434	1 391	2 210	7 904
2025	446	1.427	2 268	8,095
2026	451	1,439	2 291	8 162
2027	451	1,439	2 291	8 162
2028	450	1.437	2.291	8.162
2029	451	1.439	2 291	8 162
2030	451	1,439	2,291	8,162

RPM Bid Amount	Monthly Peak (MW)	
Year	CSP	AEP-East
2011	25	57
2012	42	112
2013	62	189
2014	66	235
2015	78	280
2016	83	299
2017	75	281
2018	65	258
2019	67	257
2020	82	272
2021	91	266
2022	85	225
2023	66	166
2024	49	128
2025	37	100
2026	24	67
2027	12	35
2028	3	7
2029	0	0
2030	0	0

Delayed Demand Forecast Impact	Monthly Peak (MW)	
Year	CSP	AEP-East
2011	0	0
2012	0	0
2013	0	0
2014	33	76
2015	56	149
2016	83	252
2017	121	390
2018	160	523
2019	193	650
2020	222	765
2021	247	866
2022	283	993
2023	331	1.128
2024	368	1.221
2025	397	1,293
2026	419	1.350
2027	434	1 391
2028	446	1.427
2029	451	1,439
2030	451	1,439

(RPM Bid + Delayed Impact) - Forecasted	Monthly Peak (MW)	
Year	CSP	AEP-East
2011	(8)	(19)
2012	(14)	(37)
2013	(21)	(63)
2014	(22)	(76)
2015	(26)	(93)
2016	(26)	(100)
2017	(25)	(94)
2018	(22)	(86)
2019	(22)	(86)
2020	(27)	(91)
2021	(30)	(89)
2022	(29)	(75)
2023	(22)	(55)
2024	(16)	(43)
2025	(12)	(33)
2026	(8)	(22)
2027	(4)	(12)
2028	(1)	(2)
2029	(0)	0
2030	0	(0)

DEMAND & ENERGY

PJM	Monthly Peak Demand (MW)			
Year	I&M (PJM)	I&M (Internal)	AEP-East (PJM)	AEP-East (Internal)
2011	4,268	4,224	20,515	20,809
2012	4,389	4,327	21,098	21,074
2013	4,496	4,434	21,610	21,394
2014	4,552	4,463	21,682	21,560
2015		4,466		21,709
2016		4,499		21,827
2017		4,536		22,013
2018		4,562		22,194
2019		4,590		22,398
2020		4,596		22,560
2021		4,624		22,823
2022		4,642		23,022
2023		4,665		23,186
2024		4,686		23,324
2025		4,733		23,573
2026		4,768		23,763
2027		4,803		23,963
2028		4,831		24,129
2029		4,877		24,354
2030		4,917		24,573
2011		4,224		20,809
2030		4,917		24,573
Total Growth		693		3,764
Compound Growth Rate		0.80%		0.88%

PJM (AEP-Traditional)	Annual Energy (GWh)	
Year	I&M	AEP-East
2011	25,561	125,676
2012	26,291	128,105
2013	26,893	129,628
2014	27,017	130,287
2015	27,115	130,858
2016	27,201	131,584
2017	27,332	132,272
2018	27,436	133,034
2019	27,561	133,912
2020	27,615	134,867
2021	27,692	135,924
2022	27,762	136,890
2023	27,872	137,789
2024	28,029	138,678
2025	28,205	139,569
2026	28,380	140,460
2027	28,555	141,438
2028	28,744	142,501
2029	28,936	143,476
2030	29,137	144,538
2011	25,561	125,676
2030	29,137	144,538
Total Growth	3,576	18,862
Compound Growth Rate	0.69%	0.73%

ACTIVE DSM (DR)

Interruptible Demand Response	Monthly Peak (MW)		Annual Energy (GWh)	
Year	I&M	AEP-East	I&M	AEP-East
2011	240	445		
2012	240	445		
2013	240	445		
2014	240	445		
2015	240	445		
2016	240	445		
2017	240	445		
2018	240	445		
2019	240	445		
2020	240	445		
2021	240	445		
2022	240	445		
2023	240	445		
2024	240	445		
2025	240	445		
2026	240	445		
2027	240	445		
2028	240	445		
2029	240	445		
2030	240	445		

Active Demand Response	Monthly Peak (MW)	
Year	I&M	AEP-East
2011	5	47
2012	6	50
2013	6	50
2014	33	180
2015	55	300
2016	83	450
2017	110	600
2018	112	612
2019	114	624
2020	117	637
2021	119	649
2022	121	662
2023	124	676
2024	126	689
2025	129	703
2026	129	703
2027	129	703
2028	129	703
2029	129	703
2030	129	703

Active + Interruptible Demand Response	Monthly Peak (MW)	
Year	I&M	AEP-East
2011	244	492
2012	246	495
2013	246	495
2014	273	625
2015	295	745
2016	322	895
2017	350	1,045
2018	352	1,057
2019	354	1,070
2020	356	1,082
2021	359	1,095
2022	361	1,108
2023	364	1,121
2024	366	1,134
2025	369	1,148
2026	369	1,148
2027	369	1,148
2028	369	1,148
2029	369	1,148
2030	369	1,148

PASSIVE DSM (EE)

Forecasted EE	Monthly Peak (MW)		Annual Energy (GWh)	
Year	I&M	AEP-East	I&M	AEP-East
2011	9	76	61	611
2012	17	149	122	968
2013	43	252	272	1,467
2014	90	390	517	2,232
2015	131	523	749	2,968
2016	166	650	957	3,699
2017	203	765	1,175	4,351
2018	241	866	1,398	4,927
2019	275	993	1,605	5,651
2020	291	1,128	1,708	6,419
2021	293	1,221	1,714	6,920
2022	294	1,293	1,718	7,325
2023	294	1,350	1,720	7,651
2024	293	1,391	1,721	7,904
2025	294	1,427	1,721	8,095
2026	294	1,439	1,720	8,162
2027	294	1,439	1,720	8,162
2028	293	1,437	1,720	8,162
2029	294	1,439	1,720	8,162
2030	294	1,439	1,720	8,162

RPM Bid Amount	Monthly Peak (MW)	
Year	I&M	AEP-East
2011	6	57
2012	13	112
2013	33	189
2014	61	235
2015	85	280
2016	92	299
2017	85	281
2018	82	258
2019	81	257
2020	65	272
2021	39	266
2022	14	225
2023	2	168
2024	0	128
2025	0	100
2026	0	67
2027	0	36
2028	0	7
2029	0	0
2030	0	0

Delayed Demand Forecast Impact	Monthly Peak (MW)	
Year	I&M	AEP-East
2011	0	0
2012	0	0
2013	0	0
2014	9	76
2015	17	149
2016	43	252
2017	90	390
2018	131	523
2019	166	650
2020	203	765
2021	241	866
2022	275	993
2023	291	1,128
2024	293	1,221
2025	294	1,293
2026	294	1,350
2027	293	1,391
2028	294	1,427
2029	294	1,439
2030	294	1,439

(RPM Bid + Delayed Impact) - Forecasted	Monthly Peak (MW)	
Year	I&M	AEP-East
2011	(3)	(19)
2012	(4)	(37)
2013	(11)	(63)
2014	(20)	(78)
2015	(29)	(93)
2016	(31)	(100)
2017	(28)	(94)
2018	(27)	(85)
2019	(27)	(86)
2020	(23)	(91)
2021	(13)	(89)
2022	(5)	(75)
2023	(1)	(55)
2024	(0)	(43)
2025	(0)	(33)
2026	(0)	(22)
2027	(0)	(12)
2028	1	(2)
2029	0	0
2030	(0)	(0)

DEMAND & ENERGY

PJM Year	Monthly Peak Demand (MW) OPCo (PJM)	OPCo (Internal)	AEP-East (PJM)	AEP-East (Internal)
2011	4.945	5.046	20.515	20.609
2012	5,056	5 180	21.098	21 074
2013	5 209	5 247	21.610	21 394
2014	5,275	5,264	21,682	21,560
2015		5.278		21.709
2016		5.297		21,827
2017		5.341		22,013
2018		5,379		22.194
2019		5.422		22 396
2020		5,464		22,560
2021		5 537		22,823
2022		5.590		23,022
2023		5 633		23,186
2024		5 656		23,324
2025		5.705		23,573
2026		5 741		23,763
2027		5 779		23.963
2028		5,814		24 129
2029		5,866		24 354
2030		5.911		24,573

2011		5,046		20,809
2030		5,911		24,573
Total Growth		865		3,764
Compound Growth Rate		0.84%		0.88%

PJM (AEP-Traditional) Year	Annual Energy (GWh) OPCo	AEP-East
2011	32,099	125,876
2012	33,085	128.105
2013	33.407	129,628
2014	33,453	130.287
2015	33,465	130.858
2016	33 582	131 594
2017	33.720	132 272
2018	33,891	133 034
2019	34,091	133 912
2020	34,364	134,867
2021	34,671	135 924
2022	34 950	136 890
2023	35.175	137 709
2024	35 377	138 678
2025	35,556	139.569
2026	35 743	140,450
2027	35 960	141.438
2028	36.212	142 501
2029	36,446	143 476
2030	36,706	144,538

2011	32,099	125.876
2030	36,706	144,538
Total Growth	4,607	18,662
Compound Growth Rate	0.71%	0.73%

ACTIVE DSM (DR)

Interruptible Demand Response Year	Monthly Peak (MW) OPCo	AEP-East	Annual Energy (GWh) OPCo	AEP-East
2011	78	445		
2012	78	445		
2013	78	445		
2014	78	445		
2015	78	445		
2016	78	445		
2017	78	445		
2018	78	445		
2019	78	445		
2020	78	445		
2021	78	445		
2022	78	445		
2023	78	445		
2024	78	445		
2025	78	445		
2025	78	445		
2027	78	445		
2028	78	445		
2029	78	445		
2030	78	445		

Active Demand Response Year	Monthly Peak (MW) OPCo	AEP-East
2011	21	47
2012	21	50
2013	21	50
2014	44	180
2015	73	300
2016	109	450
2017	145	600
2018	148	612
2019	151	624
2020	154	637
2021	157	649
2022	160	662
2023	163	676
2024	167	689
2025	170	703
2026	170	703
2027	170	703
2028	170	703
2029	170	703
2030	170	703

Active + Interruptible Demand Response Year	Monthly Peak (MW) OPCo	AEP-East
2011	99	492
2012	99	495
2013	99	495
2014	122	625
2015	151	745
2016	187	895
2017	223	1,045
2018	226	1.057
2019	229	1,070
2020	232	1.082
2021	235	1.095
2022	238	1 108
2023	241	1 121
2024	245	1.134
2025	248	1 148
2026	248	1 148
2027	248	1 148
2028	248	1 148
2029	248	1 148
2030	248	1,148

PASSIVE DSM (EE)

Forecasted EE Year	Monthly Peak (MW) OPCo	AEP-East	Annual Energy (GWh) OPCo	AEP-East
2011	31	76	238	611
2012	63	149	393	988
2013	101	252	554	1.467
2014	143	390	787	2 232
2015	185	523	1 015	2.968
2016	220	650	1.211	3,699
2017	251	765	1 378	4 351
2018	278	866	1 522	4 927
2019	324	993	1 777	5 651
2020	356	1 128	2 118	6.419
2021	435	1,221	2 385	6 920
2022	475	1.293	2 604	7.325
2023	507	1,350	2.781	7,651
2024	531	1,391	2 920	7.904
2025	551	1.427	3 026	8,085
2026	559	1,439	3 072	8 162
2027	559	1.439	3.072	8 162
2028	558	1.437	3 072	8 162
2029	560	1,439	3 072	8.162
2030	560	1,439	3,072	8,162

RPM Bid Amount Year	Monthly Peak (MW) OPCo	AEP-East
2011	24	57
2012	47	112
2013	76	189
2014	84	235
2015	92	260
2016	90	299
2017	81	281
2018	69	258
2019	78	257
2020	101	272
2021	118	266
2022	113	225
2023	91	165
2024	72	128
2025	57	100
2026	39	67
2027	21	35
2028	5	7
2029	0	0
2030	0	0

Delayed Demand Forecast Impact Year	Monthly Peak (MW) OPCo	AEP-East
2011	0	0
2012	0	0
2013	0	0
2014	31	76
2015	63	149
2016	101	252
2017	143	390
2018	185	523
2019	220	650
2020	251	765
2021	278	866
2022	324	993
2023	356	1 128
2024	435	1 221
2025	475	1 293
2026	507	1 350
2027	531	1 391
2028	551	1,427
2029	559	1,439
2030	559	1,439

(RPM Bid + Delayed Impact) - Forecasted Year	Monthly Peak (MW) OPCo	AEP-East
2011	(8)	(19)
2012	(16)	(37)
2013	(25)	(63)
2014	(26)	(78)
2015	(31)	(93)
2016	(30)	(100)
2017	(27)	(94)
2018	(23)	(86)
2019	(26)	(86)
2020	(34)	(91)
2021	(39)	(89)
2022	(33)	(75)
2023	(30)	(55)
2024	(24)	(43)
2025	(19)	(33)
2026	(13)	(22)
2027	(7)	(12)
2028	(2)	(3)
2029	(0)	0
2030	(0)	(0)

KENTUCKY POWER COMPANY

Projected Resource Capacity, Load/Peak Demands, and PJM UCAP Reserve Margins ("CLR")--PJM FRR Planning Perspective

Based on September 2011 Load Forecast

(2011/2012 - 2030/2031 PJM Planning Years)

"Going-In" Capacity Position (No New Thermal Resource Additions or Purchases)

(Assuming U.S. EPA [Proposed] EGU MACT Rulemaking "ACCELERATED" Unit Retirements re: BS1)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
				=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
	Obligation to PJM										Resources								I&M Position (MW)	
Planning Year	Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions Units	Planned Capacity Additions MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2011 /12 (k)	1,218	(2)	(1)	1,217	2	0.955	1.083	1,317	0	1,317	1,470	104				1,366	6.26%	1,280	(37)	(37)
2012 /13 (k)	1,253	(4)	(1)	1,252	4	0.950	1.080	1,348	0	1,348	1,470	58				1,412	7.15%	1,311	(37)	(37)
2013 /14 (k)	1,283	(7)	(1)	1,282	4	0.957	1.080	1,382	0	1,382	1,470	(6)				1,476	7.38%	1,367	(15)	(15)
2014 /15 (k)	1,300	(9)	(2)	1,298	11	0.956	1.081	1,392	0	1,392	1,192	(6)				1,198	7.09%	1,113	(279)	(279)
2015 /16	1,247	(10)	(4)	1,243	18	0.956	1.081	1,326	0	1,326	1,180	(5)				1,185	7.09%	1,101	(225)	(225)
2016 /17	1,252	(15)	(7)	1,246	26	0.956	1.081	1,319	0	1,319	1,187	(7)				1,194	7.09%	1,109	(210)	(210)
2017 /18	1,256	(18)	(9)	1,247	35	0.956	1.081	1,312	0	1,312	1,187	(8)				1,195	7.09%	1,110	(202)	(202)
2018 /19	1,271	(20)	(10)	1,260	36	0.956	1.081	1,325	0	1,325	1,187	(8)				1,195	7.09%	1,110	(215)	(215)
2019 /20	1,281	(21)	(15)	1,266	36	0.956	1.081	1,331	0	1,331	1,193	(5)				1,198	7.08%	1,113	(218)	(218)
2020 /21	1,287	(23)	(18)	1,269	37	0.956	1.081	1,333	0	1,333	1,198	(4)				1,202	7.08%	1,117	(216)	(216)
2021 /22	1,299	(23)	(20)	1,279	38	0.956	1.081	1,344	0	1,344	1,198	(3)				1,201	7.08%	1,116	(228)	(228)
2022 /23	1,309	(24)	(21)	1,287	39	0.956	1.081	1,352	0	1,352	1,198	(2)				1,200	7.08%	1,115	(237)	(237)
2023 /24	1,313	(23)	(23)	1,290	39	0.956	1.081	1,354	0	1,354	1,198	(1)				1,199	7.08%	1,114	(240)	(240)
2024 /25	1,320	(23)	(23)	1,296	40	0.956	1.081	1,360	0	1,360	1,198	0				1,198	7.08%	1,113	(247)	(247)
2025 /26	1,333	(23)	(24)	1,310	41	0.956	1.081	1,373	0	1,373	1,198	0				1,198	7.08%	1,113	(260)	(260)
2026 /27	1,344	(23)	(23)	1,320	41	0.956	1.081	1,385	0	1,385	1,198	0				1,198	7.08%	1,113	(272)	(272)
2027 /28	1,354	(23)	(23)	1,331	41	0.956	1.081	1,397	0	1,397	1,198	0				1,198	7.08%	1,113	(284)	(284)
2028 /29	1,362	(24)	(23)	1,338	41	0.956	1.081	1,404	0	1,404	1,198	0				1,198	7.08%	1,113	(291)	(291)
2029 /30	1,369	(23)	(23)	1,346	41	0.956	1.081	1,412	0	1,412	1,198	0				1,198	7.08%	1,113	(299)	(299)
2030 /31	1,379	(23)	(23)	1,356	41	0.956	1.081	1,423	0	1,423	1,198	0				1,198	7.08%	1,113	(310)	(310)

Notes: (a) Based on (September 2011) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and IVV
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the impact of new DSM is 'delayed' three years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.5%(2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) EFFICIENCY IMPROVEMENTS:
2015/16: Rockport 1: 36 MW (turbine upgrade) (offset to DFGD derate)
2019/20: Rockport 2: 36 MW (turbine upgrade)
2020/21: Rockport 2: 35 MW (valve upgrade)

(g) continued
DFGD DERATES:
1/2016: Rockport 1: 35 MW
1/2016: Big Sandy 2: 12 MW
RETIREMENTS (Under "BASE [EGU MACT-ACCELERATED]" view):
1/2015: Big Sandy 1

(h) Includes (MLR Share, pre-2014) of:
<Purchase> (from Constellation) of 315 MW in 2011/12
Commitment (for FRR purposes) of 22 MW from Tanners Ck 4
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2011/1:
RPM Auction Sales 2011/12 - 2013/14 (1414, 696, 761) (MW IC
3.6 MW capacity <credit> from SEPA's Philpot Dam via Blue Ri
Plus:
Estimated I&M nominations for PJM EE ('passive' DR program)
as part of PJM's emerging auction products (eff: 2014/15)

(i) Any new wind and solar capacity value is assumed to be 13% an

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCa
as of twelve months ended 9/30 of the previous year... Forecast

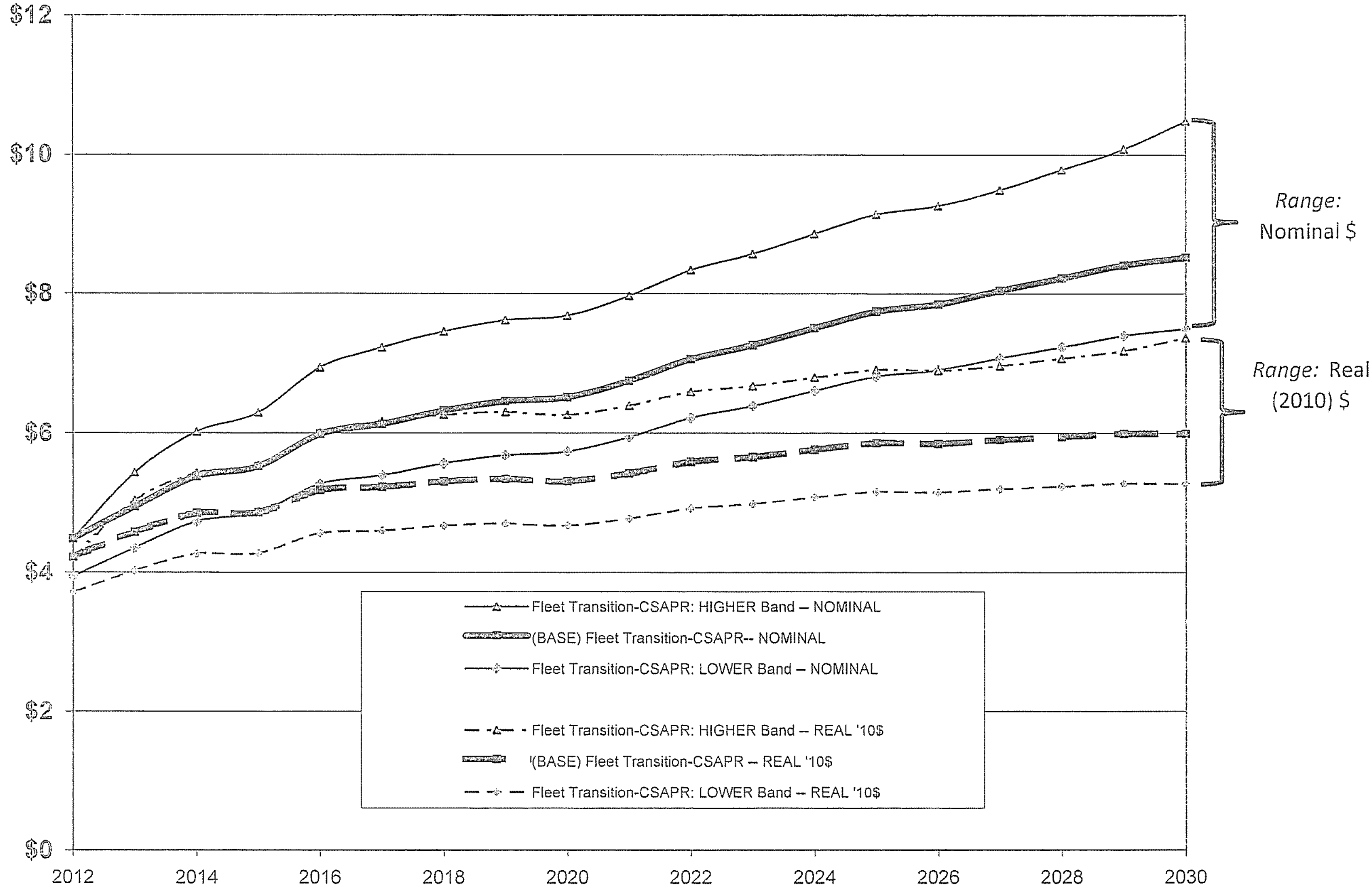
(k) PJM latest forecast of AEP Zonal coincident peak demand (alloca
which are ultimately utilized to established capacity position

(l) Through the PJM 2014/15 Planning Year, I&M capacity position h
perspective, under the Fixed Resource Requirement (FRR) plan

Natural Gas Prices (@ Henry Hub... per MMBtu)

Projected Price "Banding"

(AEP Fundamental Analysis Forecast)



Summary of Long-Term Commodity Price Forecast Scenarios
(Source: AEP Fundamental Analysis)
Annual Average (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
2012	4.48	4.48	3.94	4.48	4.48
2013	4.94	5.43	4.35	4.94	4.94
2014	5.38	6.02	4.73	5.38	5.38
2015	5.52	6.29	4.86	5.52	5.52
2016	5.99	6.94	5.27	5.99	5.99
2017	6.13	7.23	5.39	6.42	6.13
2018	6.32	7.46	5.56	6.60	6.32
2019	6.46	7.62	5.68	6.73	6.46
2020	6.52	7.69	5.73	6.78	6.52
2021	6.75	7.97	5.94	7.06	6.60
2022	7.07	8.34	6.22	7.22	6.68
2023	7.26	8.57	6.39	7.35	6.86
2024	7.51	8.86	6.61	7.51	7.10
2025	7.75	9.14	6.82	7.75	7.32
2026	7.85	9.26	6.91	7.85	7.42
2027	8.04	9.49	7.08	8.04	7.60
2028	8.22	9.78	7.23	8.22	7.77
2029	8.41	10.08	7.40	8.41	7.94
2030	8.52	10.48	7.50	8.52	8.05

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
2012	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00
2014	0.00	0.00	0.00	0.00	0.00
2015	0.00	0.00	0.00	0.00	0.00
2016	0.00	0.00	0.00	0.00	0.00
2017	0.00	0.00	0.00	15.08	0.00
2018	0.00	0.00	0.00	15.28	0.00
2019	0.00	0.00	0.00	15.47	0.00
2020	0.00	0.00	0.00	15.68	0.00
2021	0.00	0.00	0.00	15.88	0.00
2022	15.08	15.48	15.48	16.08	0.00
2023	15.28	15.67	15.67	16.29	0.00
2024	15.48	15.88	15.88	16.50	0.00
2025	15.67	16.08	16.08	16.72	0.00
2026	15.88	16.29	16.29	16.94	0.00
2027	16.08	16.50	16.50	17.16	0.00
2028	16.29	16.72	16.72	17.38	0.00
2029	16.50	16.94	16.94	17.60	0.00
2030	16.72	17.12	17.16	17.84	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
2012	56.75	64.13	53.91	56.75	56.75
2013	58.00	66.70	53.36	58.00	58.00
2014	60.00	69.00	53.40	60.00	60.00
2015	62.36	72.34	55.50	62.36	62.36
2016	64.72	75.08	57.60	64.72	64.72
2017	65.92	76.47	58.67	64.00	65.92
2018	67.18	77.93	59.79	65.22	67.18
2019	68.45	79.40	60.92	66.46	68.45
2020	69.71	80.87	62.05	67.68	69.71
2021	71.18	82.57	63.35	69.10	71.18
2022	70.90	82.24	63.10	70.55	72.67
2023	72.37	83.95	64.41	72.02	74.18
2024	73.87	85.69	65.74	73.51	75.71
2025	75.38	87.44	67.09	75.01	77.26
2026	76.91	89.22	68.45	76.54	78.84
2027	78.46	91.02	69.83	78.08	80.43
2028	80.04	92.85	71.24	79.65	82.04
2029	81.65	94.71	72.66	81.25	83.69
2030	83.27	96.60	74.11	82.87	85.36

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
2012	79.97	91.46	75.97	79.97	79.97
2013	83.46	97.95	75.11	83.46	83.46
2014	84.83	101.44	74.65	84.83	84.83
2015	85.21	102.25	74.98	85.21	85.21
2016	85.52	102.62	75.26	85.52	85.52
2017	85.31	102.37	75.07	82.83	85.31
2018	86.94	104.33	76.51	84.41	86.94
2019	88.58	106.30	77.95	86.00	88.58
2020	90.22	108.26	79.39	87.59	90.22
2021	92.07	110.48	81.02	89.38	92.07
2022	91.66	109.99	80.66	91.21	93.95
2023	93.52	112.22	82.30	93.07	95.86
2024	95.41	114.49	83.96	94.94	97.79
2025	97.31	116.77	85.63	96.84	99.74
2026	99.24	119.09	87.33	98.76	101.72
2027	101.19	121.43	89.05	100.70	103.72
2028	103.18	123.81	90.80	102.68	105.76
2029	105.19	126.23	92.57	104.68	107.82
2030	107.24	128.69	94.37	106.72	109.92

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
2012	50.57	55.16	47.59	49.73	50.30
2013	50.14	55.48	44.98	48.59	47.85
2014	54.24	62.03	49.26	54.28	54.45
2015	56.71	65.49	53.60	56.42	56.79
2016	63.56	71.80	58.75	62.42	63.74
2017	63.48	71.72	59.20	71.64	64.41
2018	64.18	73.15	60.06	72.73	65.25
2019	65.44	74.08	60.90	73.21	66.31
2020	66.33	75.16	60.86	73.82	66.55
2021	67.64	77.00	62.38	75.75	67.28
2022	76.79	85.88	72.64	77.34	68.31
2023	78.33	87.97	74.25	78.43	70.32
'024	80.34	89.78	74.99	79.55	71.04
025	82.18	92.27	76.25	81.48	73.07
2026	83.23	93.67	77.71	82.70	73.94
2027	84.57	95.54	79.22	84.24	75.28
2028	86.25	98.14	80.55	86.25	76.51
2029	87.64	100.30	81.53	87.32	77.70
2030	89.34	103.70	82.78	88.75	78.95

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
2012	30.92	33.66	29.07	30.33	30.27
2013	30.55	35.01	28.55	30.15	29.97
2014	33.26	38.84	31.15	32.95	33.34
2015	33.89	40.47	32.16	33.73	34.34
2016	39.57	45.94	36.16	38.65	40.12
2017	41.57	48.09	38.59	51.00	41.67
2018	42.57	49.48	39.25	52.03	42.70
2019	43.60	50.18	40.01	52.82	43.47
2020	44.18	51.40	40.52	53.54	44.35
2021	45.76	53.01	41.76	55.14	45.22
2022	55.93	63.44	52.41	56.56	46.22
2023	56.84	65.25	53.42	57.35	47.67
'024	58.85	66.65	54.17	58.69	48.94
025	60.37	68.79	55.93	60.38	50.72
2026	61.06	70.11	56.67	61.28	51.59
2027	62.64	72.07	58.15	62.85	53.19
2028	64.05	74.08	59.05	64.56	54.40
2029	65.66	76.20	60.20	65.80	55.78
2030	67.49	78.87	61.12	66.82	56.65

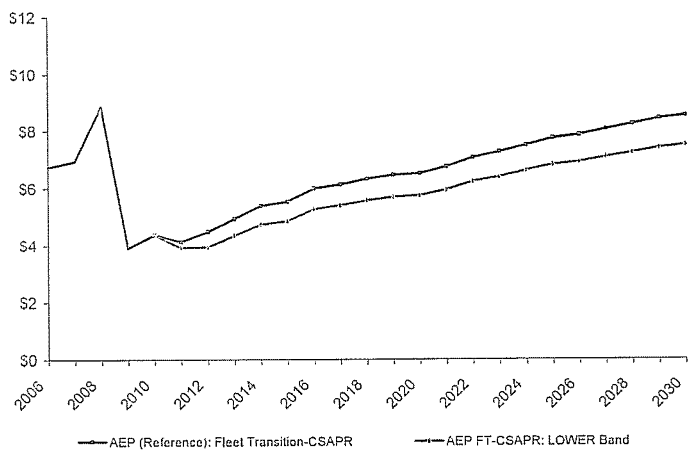
Capacity Value (PJM-RTO RPM) ($/MW-Day)

	'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
2012	16.46	16.46	16.46	16.46	16.46 *
2013	27.73	27.73	27.73	27.73	27.73 *
2014	126.00	126.00	126.00	126.00	126.00 *
2015	215.25	215.25	215.25	215.25	215.25
2016	281.92	281.92	281.92	281.92	281.92
2017	235.98	199.63	230.85	210.98	240.98
2018	200.39	166.43	179.76	180.39	205.39
2019	224.57	211.40	186.64	214.57	230.57
2020	253.47	253.86	212.57	243.47	261.47
2021	280.05	293.65	238.70	265.05	295.05
2022	304.18	330.64	264.71	289.18	322.18
2023	325.73	364.68	288.14	310.73	345.73
'024	344.58	391.96	308.40	329.58	364.58
025	360.58	405.21	325.58	345.58	380.58
2026	373.61	411.28	340.04	358.61	394.61
2027	383.50	417.45	350.60	363.50	405.50
2028	390.13	423.72	358.23	370.13	413.13
2029	392.94	430.07	362.96	372.94	416.94
2030	392.16	436.27	361.29	372.16	418.16

* Represents PJM-RTO (i.e. "western" or "rest-of-market" PJM) Base Residual Auction UCAP clearing prices for those respective XXXX/(XXXX+1) forward PJM Planning Years

					AEO 2011	Mar-11 Consultant 1	Jun-11 Consultant 1	Mar-11 Consultant 1	May-11 Consultant 2	May-11 Consultant 2	May-11 Consultant 2				Oct-11 Consultant 1	Oct-11 Consultant 2	Consultant 2
	History	AEP FT-CSAPR: LOWER Band	AEP (Reference): Fleet Transition-	AEP Fleet Transition (CO_2 in 2017)	EIA AEO 2011	Vortex	Global Redesign	Metamorphosis	Lower	Reference	High (OLG)	Max	Min	Consultant Range	Monthly		Delta Ref vs NY Sem
2006	$ 6.74											$0.00	$0.00				
2007	$ 6.95											$0.00	$0.00				
2008	$ 8.85											$0.00	$0.00				
2009	$ 3.92											$0.00	$0.00				
2010	$ 4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$4.38	$0.00			
2011		$3.92	$4.13	$4.13	$4.58	$4.06	$4.23	$4.95	$3.67	$4.29	$5.19	$4.58	$3.67	$0.91	$4.11	$4.14	$0.15
2012		$3.94	$4.48	$4.19	$4.65	$4.56	$4.58	$6.20	$3.47	$4.45	$5.68	$4.65	$3.47	$1.18	$3.95	$4.30	$0.15
2013		$4.35	$4.94	$4.70	$4.79	$4.43	$5.13	$7.47	$3.66	$4.74	$6.55	$5.13	$3.66	$1.47	$4.62	$4.55	$0.19
2014		$4.73	$5.38	$5.06	$4.89	$4.78	$5.04	$7.59	$3.97	$5.13	$8.03	$5.13	$3.97	$1.16	$5.03	$4.78	$0.35
2015		$4.86	$5.52	$5.20	$5.09	$4.96	$5.17	$8.12	$4.41	$5.65	$9.43	$5.65	$4.41	$1.24	$5.08	$5.11	$0.54
2016		$5.27	$5.99	$5.41	$5.27	$4.63	$5.47	$8.81	$4.74	$6.12	$11.22	$6.12	$4.63	$1.49	$5.10	$5.57	$0.55
2017		$5.39	$6.13	$5.56	$5.41	$4.45	$5.68	$9.04	$4.97	$6.62	$12.35	$6.62	$4.45	$2.17	$5.30	$6.05	$0.57
2018		$5.56	$6.32	$6.07	$5.58	$4.23	$5.39	$9.25	$5.20	$7.13	$13.52	$7.13	$4.23	$2.90	$5.34	$6.54	$0.59
2019		$5.68	$6.46	$6.29	$5.77	$4.52	$5.49	$9.34	$5.44	$7.54	$15.00	$7.54	$4.52	$3.02	$5.43	$6.93	$0.61
2020		$5.73	$6.52	$6.45	$6.10	$4.98	$5.42	$9.64	$5.69	$7.96	$16.54	$7.96	$4.98	$2.98	$5.39	$7.46	$0.50
2021		$5.94	$6.75	$6.68	$6.45	$5.18	$5.63	$9.21	$5.80	$8.51	$17.27	$8.51	$5.18	$3.33	$5.66		
2022		$6.22	$7.07	$6.81	$6.76	$5.43	$5.79	$8.96	$6.18	$9.08	$17.90	$9.08	$5.43	$3.65	$5.83		
2023		$6.39	$7.26	$6.99	$7.12	$5.29	$5.76	$8.79	$6.51	$9.65	$19.67	$9.65	$5.29	$4.36	$5.87		
2024		$6.61	$7.51	$7.22	$7.53	$4.76	$5.92	$8.60	$6.98	$10.47	$19.78	$10.47	$4.76	$5.71	$6.01		
2025		$6.82	$7.75	$7.43	$7.90	$4.75	$6.21	$8.41	$7.40	$11.16	$19.73	$11.16	$4.75	$6.41	$6.26	$10.29	$0.87
2026		$6.91	$7.85	$7.55	$8.21	$4.51	$6.51	$8.27				$8.21	$4.51	$3.70	$6.53		
2027		$7.08	$8.04	$7.71	$8.56	$4.52	$6.61	$8.29				$8.56	$4.52	$4.04	$6.64		
2028		$7.23	$8.22	$7.87	$8.82	$4.62	$6.74	$8.31				$8.82	$4.62	$4.20	$6.79		
2029		$7.40	$8.41	$8.06	$9.04	$4.71	$6.98	$8.63				$9.04	$4.71	$4.33	$6.97		
2030		$7.50	$8.52	$8.16	$9.28	$4.72	$6.89	$8.15				$9.28	$4.72	$4.56	$6.89		

Henry Hub Prices--External Comparison (nominal $/mmBtu)



Consultants' 2011 Projection Range ('Reference'-to-'Lower Band')

Summary: Big Sandy Unit 2 FGD Technology & Fuel Screening
Relative Economic (<COST> / SAVINGS) vs. Lowest Cost Case
Ranked in order of "Relative 10-Yr IRR" (as well as other objective risk factors)

#	CASE #	DESCRIPTION	Relative 10yr NPV ($000s)	Relative 10yr IRR	Relative 20yr NPV ($000s)	Relative 20yr IRR	Relative Payback (Yrs.)
1	Case 23	BS2 FGD Case 23 NID EST-3B [4.5 lb/Mmbtu]	-	-	-	-	-
2	Case 21	BS2 FGD Case 21 NID Base EST-1B [3.0 lb/Mmbtu]	($1,661)	**-0.7%**	($8,255)	-0.2%	0.2
3	Case 7	BS2 FGD Case 7 Dry Base EST-1B [3.0 lb/Mmbtu]	($54,330)	**-1.4%**	($52,307)	-0.7%	0.5
4	Case 19	BS2 FGD Case 19 NID EST-3A [4.5 lb/Mmbtu]	($48,371)	**-3.7%**	($44,669)	-0.7%	0.5
5	Case 1	BS2 FGD Case 1 Wet Base EST-1A [4.5 lb/Mmbtu]	($218,049)	**-4.0%**	($182,078)	-1.8%	5.3
6	Case 17	BS2 FGD Case 17 NID Base EST-1A [3.0 lb/Mmbtu]	($49,352)	**-4.3%**	($51,397)	-0.9%	0.7
7	Case 3	BS2 FGD Case 3 Wet EST-3A [3.0 lb/Mmbtu]	($213,530)	**-4.5%**	($183,767)	-1.9%	5.8
8	Case 5	BS2 FGD Case 5 Dry Base EST-1A [3.0 lb/Mmbtu]	($105,270)	**-5.4%**	($102,801)	-1.5%	3.6
9	Case 8	BS2 FGD Case 8 Dry Est-2B [1.7 lb/Mmbtu]	$38,234	**-7.4%**	($5,199)	-1.0%	0.8
10	Case 22	BS2 FGD Case 22 NID EST-2B [1.7 lb/Mmbtu]	$85,581	**-7.6%**	$31,016	-0.6%	0.4
11	Case 2	BS2 FGD Case 2 Wet EST-2A [1.7 lb/Mmbtu]	($137,733)	**-10.8%**	($151,536)	-2.5%	5.8
12	Case 6	BS2 FGD Case 6 Dry EST-2A [1.7 lb/Mmbtu]	($10,791)	**-11.7%**	($49,772)	-1.7%	5.3
13	Case 18	BS2 FGD Case 18 NID EST-2A [1.7 lb/Mmbtu]	$39,289	**-11.7%**	($8,001)	-1.3%	2.4
14	*Case 28*	*BS2 FGD Case 28 Dry CDS w/FF [4.5 lb/Mmbtu]*	*not initially screened **				

Preliminary

Kentucky Power Company
Big Sandy 2 Technology/Fuel Screening Analysis
Strategist-Based Screening of "Best of Technology-Types"

	CASE 23 "BEST" Dry NID Tech w/ 4.5#	CASE 5 "BEST" Dry SDA-FF Tech w/ 3.0#	Case 28 "BEST" Dry CDS-FF Tech w/ 4.5#	CASE 1 "BEST" Wet Tech w/ 4.5#	BS1 FGD [1]
2014					
2015					
2016	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS2 FGD (1)	BS1 FGD BS2 FGD
2017					
2018					
2019	BS1 Retirement 1- 407 MW CC,	BS1 Retirement 1- 407 MW CC,	BS1 Retirement 1- 407 MW CC,	BS1 Retirement 1- 407 MW CC,	
2020					
~					
2025	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	1- 407 MW CC,	
2026					
2027					1- 407 MW CC,
~					
2040					

Cumulative Present Worth (CPW) of Costs ($000):
(2011-2040)

	CASE 23	CASE 5	Case 28	CASE 1	BS1 FGD
CPW	$7,478,031	$7,589,736	$7,576,725	$7,632,485	$7,545,951
Less: ICAP Revenue	$103,499	$102,794	$100,679	$95,742	$141,015
Total	$7,374,532	$7,486,942	$7,476,046	$7,536,743	$7,404,936

Savings/(Cost) vs. Case 23 ($000)					
CPW		($111,705)	($98,693)	($154,454)	($67,920)
Less: ICAP Revenue		($705)	($2,821)	($7,757)	$37,515
Total		($112,410)	($101,514)	($162,211)	($30,404)

Note:
(1) "Big Sandy 1 FGD" does NOT include estimates for required SCR as well as CCR-related costs

DRAF

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 1&2 Retrofit, Reference Prime Commodity Pricing, Path A, FGD Case 22 with CCR Related Costs Included

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Yr
2011	206,672	(12,550)	30,673	182,549	0	0	0	182,549	7,502	190,052	0	190,052	190,052	0	2010	0	958
2012	247,622	(21,032)	79,638	188,966	0	0	0	188,966	5,884	194,870	0	194,870	369,424	0	2011	0	385
2013	243,457	(30,839)	45,053	229,242	0	0	0	229,242	47,904	277,146	0	277,146	604,241	0	2012	0	161
2014	276,558	(36,404)	66,039	248,923	0	0	0	248,923	75,687	324,610	368	324,242	857,113	0	2013	30	183
2015	283,796	(42,698)	65,727	260,757	0	0	0	260,757	97,046	357,604	251	357,553	1,113,706	0	2014	23	175
2016	317,995	(45,959)	100,268	263,685	137,723	80,312	218,035	481,721	7,795	489,516	1,141	488,375	1,438,490	137,723	2015	44	490
2017	287,154	(46,518)	116,316	217,356	149,350	86,600	235,950	453,346	160,586	613,932	3,133	610,799	1,807,991	149,350	2016	64	941
2018	301,551	(46,315)	153,718	194,147	153,274	99,855	253,130	447,285	174,292	621,579	3,497	618,082	2,154,075	153,274	2017	57	1,174
2019	295,708	(48,491)	129,313	214,877	189,384	38,669	228,052	442,929	175,708	618,637	3,943	614,693	2,470,792	189,384	2018	54	1,397
2020	320,987	(49,691)	167,898	202,780	194,437	101,655	296,092	498,872	156,312	655,184	4,275	650,909	2,798,520	194,437	2019	51	1,610
2021	334,523	(53,642)	170,542	218,622	199,626	107,424	307,050	525,672	199,374	725,046	5,077	719,969	3,112,872	199,626	2020	54	1,812
2022	331,406	(55,472)	155,689	241,190	204,955	110,981	315,936	557,125	195,291	752,416	4,711	747,705	3,413,371	204,955	2021	45	2,003
2023	296,332	(70,115)	74,981	291,466	210,426	111,444	321,870	613,336	173,481	786,817	4,886	781,931	3,702,633	210,426	2022	43	2,181
2024	338,181	(69,637)	140,094	267,725	216,044	119,084	335,128	602,853	195,491	798,345	4,335	794,009	3,973,003	216,044	2023	35	2,348
2025	333,522	(69,756)	117,066	285,411	221,816	120,490	342,306	627,717	192,750	820,467	2,792	817,675	4,229,289	221,816	2024	21	2,501
2026	355,577	(71,031)	143,320	283,288	227,741	128,520	356,261	639,549	202,522	842,071	1,464	840,607	4,471,808	227,741	2025	11	2,641
2027	434,935	(59,453)	248,405	245,983	311,194	148,384	459,578	705,561	211,130	916,691	56,383	858,308	4,699,741	311,194	2026	405	2,707
2028	466,065	(59,935)	266,320	229,660	318,487	157,315	475,802	704,462	227,006	931,468	57,931	873,556	4,913,274	318,487	2027	397	2,805
2029	468,454	(60,035)	281,384	247,106	325,963	162,196	488,159	735,265	225,442	960,707	57,726	902,981	5,116,446	325,963	2028	391	2,841
2030	457,787	(61,086)	254,359	274,517	333,626	163,681	497,507	772,024	219,762	991,786	56,803	934,983	5,310,087	333,626	2029	380	2,875
2031	479,719	(62,045)	267,091	274,672	341,480	172,993	514,473	789,145	227,037	1,016,182	55,687	960,495	5,493,192	341,480	2030	368	2,910
2032	516,184	(61,898)	314,707	263,374	349,533	179,305	528,838	792,212	244,057	1,036,269	55,031	981,238	5,665,375	349,533	2031	359	2,945
2033	526,885	(62,648)	311,786	277,747	357,787	185,095	542,882	820,629	245,918	1,066,548	52,108	1,014,440	5,829,227	357,787	2032	336	2,980
2034	515,413	(64,769)	260,591	319,592	366,248	186,477	552,725	872,317	233,425	1,105,742	52,055	1,053,687	5,985,883	366,248	2033	332	3,016
2035	526,968	(66,636)	259,789	333,815	374,924	196,504	571,428	905,243	237,365	1,142,608	51,429	1,091,179	6,135,211	374,924	2034	324	3,052
2036	529,426	(66,261)	302,725	292,962	383,816	200,293	584,109	877,071	251,803	1,128,873	50,658	1,078,215	6,271,031	383,816	2035	315	3,089
2037	546,601	(66,501)	325,218	288,283	392,935	205,480	598,415	886,698	251,594	1,148,292	48,280	1,100,012	6,398,576	392,935	2036	297	3,126
2038	545,468	(68,169)	310,187	303,450	402,283	207,494	609,777	913,227	260,586	1,173,814	46,549	1,127,264	6,518,865	402,283	2037	283	3,163
2039	558,802	(69,109)	330,346	297,565	411,866	213,917	625,783	923,348	269,596	1,192,943	44,950	1,147,994	6,631,664	411,866	2038	270	3,201
2040	557,846	(70,920)	320,416	308,352	421,692	810,768	1,232,460	1,540,831	269,553	1,810,384	43,487	1,766,897	6,791,439	421,692	2039	258	3,240
2011 Net Present Value																	
Period of 2011-2040	3,770,888	(542,311)	1,566,369	2,746,810	1,722,019	840,703	2,562,722	5,409,532	1,522,922	6,932,454	141,015	6,791,439					
Base Case O&M 2011-2040							613,497			613,497	0	613,497					
Utility Cost Present Value 2011-2040							3,276,219			7,545,951	141,015	7,404,936					

KPSC Case No. 2011-00401
KIUC's First Set of Data Requests
Dated January 13, 2012
Item No. 28
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Resource Planning
Created on: January 26, 2011

Ex SCW-3A (Stategist FGD Tech-Fuel 'Family' Screening Results Summary).xls
BS1 FGD

DRAF

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 1&2 Retrofit, Reference Prime Commodity Pricing, Path A, FGD Case 22 with CCR Related Costs Included

	SO2 Emissions Total East	NSR SO2 NSR Adjusted Total ᴮ	NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	0	52,559	450,000	397,441	7,463	6,319	0.29
2012	0	59,019	414,000	354,981	8,315	6,672	0.34
2013	0	51,289	344,000	292,711	7,431	6,236	0.28
2014	0	54,334	334,000	279,666	7,718	5,492	0.30
2015	0	52,260	269,000	216,740	7,745	5,589	0.30
2016	0	5,596	254,000	248,404	8,391	6,444	0.33
2017	0	6,197	229,000	222,803	8,762	6,577	0.33
2018	0	6,021	178,000	171,979	8,784	6,809	0.35
2019	0	1,591	168,000	166,409	8,389	5,927	0.33
2020	0	1,684	168,000	166,316	8,905	6,051	0.34
2021	0	1,689	168,000	166,311	8,927	6,184	0.34
2022	0	1,631	168,000	166,369	8,634	5,902	0.33
2023	0	1,430	168,000	166,570	7,570	5,042	0.29
2024	0	1,595	168,000	166,404	8,421	5,962	0.33
2025	0	1,545	168,000	166,455	8,196	5,707	0.30
2026	0	1,610	100,000	98,390	8,502	5,938	0.33
2027	3	1,556	100,000	98,444	8,750	5,626	0.31
2028	3	1,673	100,000	98,327	9,285	6,582	0.35
2029	3	1,641	100,000	98,359	9,102	6,461	0.34
2030	3	1,556	100,000	98,444	8,767	6,291	0.31
2031	3	1,669	100,000	98,331	8,942	5,953	0.34
2032	3	1,709	100,000	98,291	9,491	6,668	0.35
2033	3	1,699	100,000	98,301	9,442	6,577	0.35
2034	3	1,572	100,000	98,428	8,850	6,310	0.31
2035	3	1,595	100,000	98,405	8,887	5,744	0.33
2036	3	1,677	100,000	98,323	9,308	6,779	0.35
2037	3	1,716	100,000	98,284	9,549	6,776	0.35
2038	3	1,689	100,000	98,311	9,392	6,769	0.35
2039	3	1,724	100,000	98,276	9,594	6,650	0.35
2040	3	1,702	100,000	98,298	9,472	6,891	0.36

	Summary of Energy Purchases and Sales (Gwh) Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / KWh)	CAGR (thru)
2011	7,633	58	115	57	427	1,212	785	7,045	290,923	480,975	6.8	
2012	7,642	138	117	(22)	182	1,995	1,812	7,053	289,285	484,155	6.9	0.5%
2013	7,648	138	36	(102)	503	1,290	787	7,059	294,367	571,513	8.1	8.9%
2014	7,638	139	17	(122)	328	1,459	1,130	7,050	301,623	626,655	8.9	9.2%
2015	7,623	139	23	(116)	342	1,451	1,109	7,036	310,633	668,186	9.5	8.6%
2016	7,648	139	19	(120)	187	2,061	1,874	7,059	313,409	801,784	11.4	10.7%
2017	7,675	139	28	(111)	180	1,915	1,735	7,084	321,132	931,931	13.2	11.6%
2018	7,709	139	37	(102)	100	2,370	2,271	7,115	332,128	950,210	13.4	10.1%
2019	7,754	139	36	(103)	185	1,983	1,799	7,157	337,451	952,145	13.3	8.7%
2020	7,798	139	34	(106)	97	2,424	2,328	7,198	340,282	1,031,191	14.3	8.6%
2021	7,848	288	34	(254)	81	2,523	2,442	7,244	347,477	1,067,446	14.7	8.0%
2022	7,903	288	34	(254)	124	2,187	2,064	7,294	349,845	1,097,550	15.0	7.4%
2023	7,957	288	34	(254)	348	1,203	855	7,344	360,647	1,142,578	15.6	7.1%
2024	8,012	289	34	(255)	132	1,884	1,752	7,395	365,998	1,160,008	15.7	6.5%
2025	8,069	288	34	(254)	269	1,688	1,419	7,447	368,701	1,186,376	15.9	6.2%
2026	8,125	288	34	(254)	168	1,896	1,728	7,500	377,102	1,217,700	16.2	5.9%
2027	8,186	288	34	(254)	141	2,857	2,716	7,556	387,215	1,245,522	16.5	5.7%
2028	8,246	289	34	(255)	87	3,301	3,214	7,613	389,382	1,262,933	16.6	5.4%
2029	8,300	288	34	(254)	96	3,061	2,965	7,661	399,077	1,302,058	17.0	5.2%
2030	8,361	288	34	(254)	235	2,846	2,611	7,717	406,645	1,341,627	17.4	5.0%
2031	8,420	288	34	(254)	110	2,782	2,672	7,772	414,203	1,374,698	17.7	4.9%
2032	8,483	289	34	(255)	55	3,258	3,203	7,830	421,501	1,403,139	17.9	4.7%
2033	8,540	288	34	(254)	68	3,183	3,095	7,883	429,743	1,444,182	18.3	4.6%
2034	8,601	288	34	(254)	204	2,657	2,453	7,938	437,730	1,491,417	18.8	4.5%
2035	8,665	288	34	(254)	191	2,591	2,400	7,998	445,866	1,537,045	19.2	4.4%
2036	8,729	289	34	(255)	83	2,895	2,812	8,057	454,153	1,532,308	19.0	4.2%
2037	8,792	288	34	(254)	54	3,072	3,018	8,115	462,594	1,562,606	19.3	4.1%
2038	8,860	288	34	(254)	61	2,850	2,789	8,178	471,191	1,598,456	19.5	4.0%
2039	8,929	288	34	(254)	39	2,991	2,952	8,242	479,949	1,627,943	19.8	3.9%
2040	8,999	289	34	(255)	75	2,857	2,782	8,306	488,869	2,255,767	27.2	4.9%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,222	1,118		0	1,118	-8.5%
2012	1,264	1,318		0	1,318	4.3%
2013	1,273	1,320		0	1,320	3.7%
2014	1,251	1,390		0	1,390	11.1%
2015	1,240	1,367		0	1,367	10.3%
2016	1,223	1,366		0	1,366	11.7%
2017	1,211	1,372		0	1,372	13.3%
2018	1,216	1,371		0	1,371	12.7%
2019	1,222	1,374		0	1,374	12.5%
2020	1,225	1,374		0	1,374	12.2%
2021	1,236	1,389		0	1,389	12.4%
2022	1,244	1,389		0	1,389	11.7%
2023	1,246	1,389		0	1,389	11.5%
2024	1,253	1,389		0	1,389	10.9%
2025	1,266	1,389		0	1,389	9.7%
2026	1,276	1,389		0	1,389	8.9%
2027	1,287	1,389	1- 407 MW CC.	407	1,796	39.6%
2028	1,295	1,389		407	1,796	38.7%
2029	1,301	1,389		407	1,796	38.1%
2030	1,311	1,389		407	1,796	37.0%
2031	1,322	1,389		407	1,796	35.9%
2032	1,330	1,389		407	1,796	35.1%
2033	1,344	1,381		407	1,788	33.1%
2034	1,348	1,381		407	1,788	32.7%
2035	1,359	1,385		407	1,792	31.9%
2036	1,367	1,385		407	1,792	31.1%
2037	1,384	1,385		407	1,792	29.5%
2038	1,397	1,385		407	1,792	28.3%
2039	1,409	1,385		407	1,792	27.2%
2040	1,420	1,385		407	1,792	26.2%

ᴬ Total East SO2 Excludes Cardinal 2&3 Emissions
ᴮ NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

Avoided Costs 2009-12

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KPSC Case No. 2011-00401
KIUC's First Set of Data Requests
Dated January 13, 2012
Item No. 28

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 2, Reference Prime Commodity Pricing, Path A, FGD Case 23 with CCR Related Costs Included

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)		Surplus MW	ICAP Value $/MW-Wk
2011	206,672	(12,556)	36,673	182,549	0	0	0	182,549	7,502	190,052	0	190,052	190,052	0	2010	0	958
2012	247,622	(21,002)	79,636	188,986	0	0	0	188,986	5,894	194,870	0	194,870	369,424	0	2011	0	388
2013	243,457	(39,539)	45,053	229,242	0	0	0	229,242	47,904	277,146	0	277,146	604,241	0	2012	0	151
2014	276,550	(36,464)	66,039	248,923	0	0	0	248,923	75,687	324,610	368	324,242	857,113	0	2013	39	165
2015	233,796	(42,669)	65,727	260,757	0	0	0	260,757	97,046	357,804	251	357,553	1,113,786	0	2014	23	175
2016	262,507	(44,739)	78,946	228,300	116,613	87,832	204,445	432,745	17,544	450,289	1,284	449,006	1,410,476	116,613	2015	50	495
2017	244,727	(45,280)	69,811	200,166	127,752	94,623	222,375	422,571	157,722	580,293	3,402	576,890	1,761,353	127,752	2016	70	941
2018	262,624	(45,540)	135,373	172,901	131,095	109,120	240,215	413,207	166,753	579,959	3,833	576,126	2,053,897	131,095	2017	63	1,174
2019	307,953	(41,449)	175,651	173,549	236,150	115,480	351,630	525,178	169,692	694,670	15,264	679,606	2,434,116	236,150	2018	210	1,337
2020	317,940	(43,383)	178,933	182,398	241,572	110,803	353,375	540,773	179,925	720,698	17,320	703,378	2,767,750	241,572	2019	207	1,610
2021	326,512	(57,752)	185,580	198,669	247,130	120,428	367,558	566,247	181,486	747,733	19,758	727,976	3,085,606	247,130	2020	210	1,812
2022	328,278	(59,174)	169,645	217,808	252,826	121,803	374,629	592,437	179,322	771,759	20,936	750,823	3,387,358	252,826	2021	201	2,003
2023	309,160	(51,443)	166,968	263,703	258,661	119,117	377,778	641,481	161,858	803,338	22,560	780,779	3,676,194	258,661	2022	193	2,181
2024	332,652	(51,175)	148,466	245,341	264,642	129,145	393,787	639,128	177,745	816,873	23,357	793,516	3,946,326	264,642	2023	191	2,348
2025	338,939	(62,236)	134,460	266,717	270,773	127,516	398,289	665,006	176,346	841,352	23,056	818,296	4,202,876	270,773	2024	177	2,501
2026	354,723	(63,166)	157,342	260,550	277,056	137,176	414,232	674,782	185,427	860,209	22,862	837,348	4,444,456	277,056	2025	166	2,641
2027	353,859	(64,059)	131,496	286,421	283,496	135,408	418,904	705,325	181,152	886,477	22,240	864,237	4,673,963	283,496	2026	155	2,767
2028	369,091	(64,776)	154,736	279,132	290,095	145,509	435,605	714,736	190,392	905,128	21,287	883,841	4,890,010	290,096	2027	146	2,605
2029	367,422	(66,459)	136,557	297,316	296,863	148,882	445,745	743,061	188,489	931,550	20,606	910,944	5,094,974	296,863	2028	133	2,841
2030	369,839	(60,223)	166,709	320,353	303,798	145,338	449,136	778,489	182,470	960,959	19,239	941,721	5,290,010	303,798	2029	129	2,875
2031	393,514	(65,941)	133,907	318,540	310,907	157,619	468,526	787,075	193,721	980,795	17,670	963,125	5,473,617	310,907	2030	117	2,910
2032	404,932	(69,944)	153,528	314,347	318,195	162,110	480,305	794,653	204,870	999,523	16,559	982,964	5,646,102	318,195	2031	109	2,545
2033	415,153	(70,027)	158,346	326,834	325,666	166,842	492,508	819,342	207,549	1,026,891	13,174	1,013,717	5,809,838	325,666	2032	85	2,980
2034	405,051	(76,900)	102,017	374,543	333,324	162,382	495,706	870,248	194,485	1,064,734	12,654	1,052,079	5,966,255	333,324	2033	81	3,016
2035	416,257	(74,012)	123,669	368,399	341,177	175,893	517,070	885,470	204,006	1,089,475	11,555	1,077,921	6,113,769	341,177	2034	73	3,052
2036	420,472	(74,977)	127,117	368,332	349,225	178,093	527,318	895,650	208,776	1,104,426	10,305	1,094,120	6,251,591	349,225	2035	64	3,089
2037	428,940	(75,500)	146,843	367,605	357,478	181,388	538,866	906,471	218,388	1,124,859	7,443	1,117,416	6,381,154	357,478	2036	46	3,126
2038	436,034	(78,076)	124,925	389,185	365,940	181,252	547,192	936,377	216,104	1,152,481	5,222	1,147,259	6,503,598	365,940	2037	32	3,163
2039	450,954	(72,341)	137,453	391,841	374,615	185,782	560,397	952,238	223,821	1,176,059	3,127	1,172,932	6,618,627	374,615	2038	19	3,201
2040	456,096	(60,425)	124,274	412,248	383,510	555,077	939,597	1,350,835	222,958	1,573,794	1,162	1,572,631	6,761,035	383,510	2039	7	3,240
2011 Net Present Value																	
Period of 2011-2040	3,458,129	(533,667)	1,239,664	2,752,132	1,760,386	960,748	2,721,134	5,473,267	1,391,268	6,864,534	103,499	6,761,035					
Base Case O&M 2011-2040							613,497			613,497	0	613,497					
Utility Cost Present Value 2011-2040							3,334,632			7,478,031	103,499	7,374,532					

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 2, Reference Prime Commodity Pricing, Path A, FGD Case 23 with CCR Related Costs Included

	SO2 Emissions Total East	NSR SO2 NSR Adjusted Total[a]	NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	0	52,559	450,000	397,441	7,468	6,319	0.29
2012	0	59,019	414,000	354,981	8,315	6,672	0.34
2013	0	51,289	344,000	292,711	7,431	6,236	0.28
2014	0	54,334	334,000	279,666	7,718	5,492	0.30
2015	0	52,260	269,000	216,740	7,745	5,569	0.30
2016	0	12,595	254,000	241,405	7,886	4,839	0.30
2017	0	12,931	229,000	216,069	7,776	4,923	0.31
2018	0	14,463	178,000	163,537	8,404	5,769	0.33
2019	3	6,503	168,000	161,497	8,102	3,305	0.29
2020	3	2,689	168,000	165,311	8,161	1,842	0.28
2021	3	2,679	168,000	165,321	8,126	1,835	0.28
2022	3	2,583	168,000	165,417	7,928	1,785	0.26
2023	3	2,270	168,000	165,730	7,063	1,578	0.23
2024	3	2,541	168,000	165,459	7,657	1,729	0.26
2025	3	2,376	168,000	165,624	7,500	1,676	0.24
2026	3	2,562	100,000	97,438	7,784	1,753	0.25
2027	3	2,378	100,000	97,622	7,508	1,677	0.24
2028	3	2,567	100,000	97,433	7,787	1,755	0.27
2029	3	2,533	100,000	97,467	7,610	1,718	0.26
2030	4	2,287	100,000	97,713	7,280	1,620	0.23
2031	3	2,538	100,000	97,462	7,530	1,722	0.26
2032	3	2,604	100,000	97,396	7,957	1,795	0.27
2033	3	2,631	100,000	97,369	7,969	1,784	0.27
2034	4	2,307	100,000	97,693	7,374	1,641	0.23
2035	3	2,544	100,000	97,456	7,638	1,723	0.27
2036	3	2,563	100,000	97,437	7,718	1,741	0.27
2037	3	2,603	100,000	97,397	7,972	1,795	0.27
2038	3	2,572	100,000	97,428	7,789	1,757	0.27
2039	3	2,605	100,000	97,395	7,965	1,785	0.27
2040	3	2,585	100,000	97,415	7,835	1,765	0.27

	Summary of Energy Purchases and Sales (Gwh) Internal Requirement	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	CAGR (thru)
2011	7,633	58	115	57	427	1,212	785	7,045	290,923	460,975	6.8	
2012	7,642	138	117	(22)	152	1,965	1,812	7,053	289,285	484,155	6.9	0.5%
2013	7,648	138	36	(102)	503	1,290	787	7,059	294,367	571,513	8.1	8.8%
2014	7,638	139	17	(122)	328	1,459	1,130	7,050	301,823	626,665	8.9	9.2%
2015	7,623	139	23	(116)	342	1,451	1,109	7,036	310,633	668,165	9.5	8.6%
2016	7,648	139	19	(120)	329	1,640	1,312	7,059	313,409	762,415	10.8	9.6%
2017	7,675	139	28	(111)	336	1,525	1,189	7,084	321,132	898,022	12.7	10.9%
2018	7,709	139	37	(102)	189	2,048	1,860	7,115	332,128	908,254	12.8	9.4%
2019	7,754	139	36	(103)	217	2,456	2,239	7,157	337,451	1,017,057	14.2	9.6%
2020	7,798	139	34	(106)	148	2,426	2,278	7,198	340,262	1,043,660	14.5	8.7%
2021	7,848	288	34	(254)	134	2,455	2,321	7,244	347,477	1,075,453	14.8	8.1%
2022	7,903	288	34	(254)	145	2,215	2,070	7,294	349,845	1,100,668	15.1	7.5%
2023	7,957	288	34	(254)	364	1,472	1,108	7,344	350,647	1,141,428	15.5	7.1%
2024	8,012	289	34	(255)	228	1,874	1,646	7,395	365,995	1,159,515	15.7	6.6%
2025	8,069	288	34	(254)	254	1,714	1,461	7,447	368,701	1,186,997	15.9	6.2%
2026	8,125	288	34	(254)	208	1,923	1,716	7,500	377,102	1,214,449	16.2	5.9%
2027	8,185	288	34	(254)	382	1,747	1,364	7,555	387,215	1,251,452	16.6	5.7%
2028	8,248	289	34	(255)	254	1,851	1,597	7,613	389,382	1,273,223	16.7	5.4%
2029	8,300	288	34	(254)	311	1,640	1,329	7,661	399,077	1,310,022	17.1	5.2%
2030	8,361	288	34	(254)	604	1,580	976	7,717	405,645	1,348,365	17.5	5.1%
2031	8,420	288	34	(254)	313	1,561	1,248	7,772	414,203	1,377,328	17.7	4.9%
2032	8,483	289	34	(255)	222	1,753	1,531	7,830	421,501	1,404,665	17.9	4.7%
2033	8,540	288	34	(254)	257	1,756	1,499	7,883	429,743	1,443,459	18.3	4.6%
2034	8,601	288	34	(254)	540	1,383	843	7,938	437,730	1,489,809	18.8	4.5%
2035	8,665	288	34	(254)	340	1,380	1,040	7,998	445,866	1,523,786	19.1	4.4%
2036	8,729	289	34	(255)	346	1,397	1,051	8,057	454,153	1,540,273	19.2	4.2%
2037	8,792	288	34	(254)	282	1,543	1,261	8,115	462,594	1,580,009	19.5	4.1%
2038	8,860	288	34	(254)	306	1,296	990	8,178	471,191	1,618,450	19.8	4.0%
2039	8,929	288	34	(254)	294	1,399	1,105	8,242	479,949	1,652,881	20.1	3.8%
2040	8,999	289	34	(255)	354	1,300	946	8,306	488,869	2,051,501	24.8	4.6%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,222	1,118		0	1,118	-8.5%
2012	1,264	1,318		0	1,318	4.3%
2013	1,273	1,320		0	1,320	3.7%
2014	1,251	1,350		0	1,350	11.1%
2015	1,240	1,367		0	1,367	10.3%
2016	1,223	1,371		0	1,371	12.1%
2017	1,211	1,378		0	1,378	13.8%
2018	1,216	1,376		0	1,376	13.2%
2019	1,222	1,123	1- 407 MW CC.	407	1,530	25.2%
2020	1,225	1,123		407	1,530	24.9%
2021	1,236	1,138		407	1,545	25.0%
2022	1,244	1,138		407	1,545	24.2%
2023	1,246	1,138		407	1,545	24.0%
2024	1,253	1,138		407	1,545	23.3%
2025	1,266	1,138		407	1,545	22.0%
2026	1,276	1,138		407	1,545	21.1%
2027	1,287	1,138		407	1,545	20.0%
2028	1,296	1,138		407	1,545	19.3%
2029	1,301	1,138		407	1,545	18.6%
2030	1,311	1,138		407	1,545	17.8%
2031	1,322	1,138		407	1,545	16.9%
2032	1,330	1,130		407	1,545	16.2%
2033	1,344	1,130		407	1,537	14.4%
2034	1,348	1,130		407	1,537	14.0%
2035	1,359	1,134		407	1,541	13.4%
2036	1,367	1,134		407	1,541	12.7%
2037	1,384	1,134		407	1,541	11.3%
2038	1,397	1,134		407	1,541	10.3%
2039	1,409	1,134		407	1,541	9.4%
2040	1,420	1,134		407	1,541	8.5%

[a] Total East SO2 Excludes Cardinal 2&3 Emissions
[a] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 2, Reference Prime Commodity Pricing, Path A, FGD Case 1 with CCR Related Cost Included

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	206,672	(12,550)	36,673	182,549	0	0	0	182,549	7,502	190,052	0	190,052	190,052	0
2012	247,622	(21,032)	79,638	168,986	0	0	0	168,986	5,884	194,670	0	194,670	369,424	0
2013	243,457	(30,835)	45,053	229,242	0	0	0	229,242	47,904	277,146	0	277,146	604,241	0
2014	276,558	(33,404)	66,039	248,923	0	0	0	248,923	75,687	324,610	368	324,242	857,113	0
2015	283,796	(42,689)	65,727	260,757	0	0	0	260,757	97,046	357,804	251	357,553	1,113,786	0
2016	267,146	(45,249)	84,644	227,753	145,103	61,513	206,616	434,368	18,292	452,660	1,018	451,642	1,412,218	145,103
2017	248,934	(45,941)	97,263	197,642	165,270	69,853	235,123	432,765	160,504	593,269	2,894	590,375	1,771,297	165,270
2018	267,166	(46,162)	143,985	169,363	169,552	86,875	256,427	425,790	169,471	595,261	3,202	592,059	2,102,761	169,552
2019	313,527	(41,660)	182,372	172,815	275,568	93,700	369,268	542,083	171,255	713,338	14,517	698,821	2,462,682	275,568
2020	324,110	(43,814)	186,239	181,667	281,977	93,144	375,121	556,808	181,482	738,290	16,463	721,827	2,805,275	281,977
2021	332,566	(66,144)	192,525	199,185	288,545	96,299	384,844	583,030	182,964	765,994	18,794	747,200	3,131,517	288,545
2022	334,422	(59,656)	176,936	217,142	295,275	98,598	393,873	611,015	180,633	791,647	19,871	771,977	3,441,770	295,275
2023	315,462	(62,607)	114,585	262,884	302,172	99,559	401,731	664,615	163,540	828,154	21,399	806,755	3,740,216	302,172
2024	339,870	(61,707)	156,842	244,735	309,241	104,740	413,981	658,716	179,510	838,227	22,108	816,119	4,018,114	309,241
2025	345,585	(62,728)	142,234	266,150	316,487	105,989	422,476	688,625	177,977	866,602	21,725	844,877	4,282,926	316,487
2026	361,905	(63,745)	165,675	259,976	323,912	111,379	435,291	695,267	187,178	882,445	21,457	860,989	4,531,325	323,912
2027	360,352	(64,591)	138,813	286,099	331,524	112,657	444,181	730,280	182,652	912,932	20,768	892,164	4,768,249	331,524
2028	376,004	(65,471)	163,416	278,658	339,326	118,229	457,555	736,214	192,197	928,411	19,795	908,615	4,990,352	339,326
2029	376,452	(67,205)	145,960	298,697	347,322	121,180	468,502	765,199	190,484	955,682	19,094	936,588	5,201,085	347,322
2030	376,609	(66,810)	114,377	329,042	355,519	122,183	477,702	806,744	184,068	990,812	17,708	973,104	5,402,622	355,519
2031	393,895	(69,945)	146,640	317,200	363,921	128,674	492,595	809,795	196,249	1,006,044	16,122	989,921	5,591,336	363,921
2032	413,543	(69,701)	169,462	313,782	372,534	132,089	504,623	818,385	206,942	1,025,326	14,992	1,010,334	5,768,625	372,534
2033	423,370	(70,854)	167,609	326,615	381,363	136,005	517,368	843,983	209,432	1,053,415	11,588	1,041,827	5,936,900	381,363
2034	413,082	(71,657)	110,415	374,324	390,414	136,683	527,097	901,421	196,192	1,097,613	11,050	1,086,564	6,098,444	390,414
2035	423,115	(75,011)	135,780	367,346	399,694	143,747	543,441	910,787	206,494	1,117,281	9,931	1,107,350	6,249,985	399,694
2036	430,723	(76,004)	139,487	367,240	409,206	145,252	554,458	921,699	211,385	1,133,084	8,662	1,124,422	6,391,625	409,206
2037	449,052	(76,405)	158,323	367,134	418,958	147,952	566,920	934,054	220,639	1,154,693	5,781	1,148,912	6,524,840	418,958
2038	445,895	(79,250)	136,463	388,683	428,957	147,226	576,183	964,866	218,399	1,183,264	3,540	1,179,725	6,650,749	428,957
2039	461,662	(78,365)	149,486	391,541	439,207	151,152	590,359	981,900	226,150	1,208,050	1,424	1,206,626	6,769,288	439,207
2040	466,671	(81,065)	138,725	411,610	449,717	615,267	1,064,984	1,476,594	225,418	1,702,012	(561)	1,702,573	6,923,246	449,717
2011 Net Present Value														
Period of 2011-2040	3,555,615	(535,049)	1,298,843	2,744,820	2,083,040	786,466	2,869,507	5,614,327	1,404,661	7,018,988	95,742	6,923,246		
Base Case O&M 2011-2040							613,497			613,497	0	613,497		
Utility Cost Present Value 2011-2040							3,483,004			7,632,485	95,742	7,536,743		

	Surplus MW	ICAP Value $/MW-Wk
2010	0	958
2011	0	388
2012	0	161
2013	39	183
2014	28	175
2015	39	496
2016	59	941
2017	52	1,174
2018	200	1,397
2019	197	1,610
2020	199	1,812
2021	191	2,003
2022	183	2,181
2023	181	2,348
2024	167	2,501
2025	156	2,641
2026	144	2,767
2027	136	2,805
2028	129	2,841
2029	118	2,875
2030	107	2,910
2031	98	2,945
2032	75	2,980
2033	70	3,016
2034	63	3,052
2035	54	3,089
2036	35	3,125
2037	22	3,163
2038	9	3,201
2039	(3)	3,240

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 2, Reference Prime Commodity Pricing, Path A, FGD Case 1 with CCR Related Cost Included

	SO2 Emissions Total East	NSR SO2 NSR Adjusted Total [a]	NSR SO2 Caps	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	0	52,559	450,000	397,441	7,460	6,319	0.29
2012	0	59,019	414,000	354,981	8,315	6,872	0.34
2013	0	51,289	344,000	292,711	7,431	6,236	0.28
2014	0	54,334	334,000	279,666	7,718	5,492	0.30
2015	0	52,260	269,000	216,740	7,745	5,589	0.30
2016	0	13,131	254,000	240,869	8,007	5,042	0.31
2017	0	13,463	229,000	215,537	7,898	5,122	0.31
2018	0	14,537	178,000	163,463	8,541	5,700	0.34
2019	3	6,168	168,000	161,832	8,177	3,072	0.29
2020	3	2,705	168,000	165,295	8,232	1,854	0.29
2021	3	2,694	168,000	165,306	8,193	1,845	0.28
2022	3	2,598	168,000	165,402	7,905	1,795	0.27
2023	4	2,289	168,000	165,711	7,136	1,591	0.23
2024	3	2,560	168,000	165,440	7,733	1,742	0.27
2025	4	2,393	168,000	165,607	7,570	1,685	0.24
2026	4	2,580	100,000	97,420	7,858	1,766	0.27
2027	4	2,392	100,000	97,608	7,570	1,687	0.24
2028	4	2,585	100,000	97,415	7,851	1,767	0.27
2029	3	2,554	100,000	97,446	7,690	1,732	0.27
2030	4	2,303	100,000	97,697	7,343	1,631	0.23
2031	4	2,564	100,000	97,436	7,730	1,739	0.27
2032	3	2,624	100,000	97,376	8,048	1,809	0.27
2033	4	2,619	100,000	97,381	8,041	1,807	0.27
2034	4	2,323	100,000	97,677	7,436	1,652	0.23
2035	4	2,570	100,000	97,430	7,731	1,740	0.27
2036	3	2,590	100,000	97,410	7,814	1,759	0.27
2037	4	2,623	100,000	97,377	8,054	1,803	0.27
2038	3	2,594	100,000	97,406	7,871	1,771	0.27
2039	3	2,624	100,000	97,376	8,048	1,809	0.27
2040	4	2,607	100,000	97,393	7,921	1,780	0.27

	Summary of Energy Purchases and Sales (Gwh): Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	TOTAL RATE IMPACT CAGR (thru)
2011	7,633	58	115	57	427	1,212	785	7,045	290,923	480,575	6.8	
2012	7,642	135	117	(22)	152	1,965	1,812	7,053	259,285	484,155	6.9	0.5%
2013	7,648	138	36	(102)	503	1,290	787	7,059	294,367	571,513	8.1	8.9%
2014	7,638	139	17	(122)	328	1,459	1,130	7,050	301,823	620,055	8.9	9.2%
2015	7,623	139	23	(116)	342	1,451	1,109	7,036	310,633	668,186	9.5	8.5%
2016	7,640	139	19	(120)	271	1,755	1,484	7,059	313,409	765,051	10.8	9.7%
2017	7,675	139	28	(111)	279	1,633	1,355	7,084	321,132	911,507	12.9	11.1%
2018	7,709	139	37	(102)	138	2,186	2,048	7,115	332,128	924,187	13.0	9.6%
2019	7,754	139	36	(103)	148	2,532	2,384	7,157	337,451	1,036,272	14.5	9.9%
2020	7,798	139	34	(105)	110	2,536	2,427	7,198	340,282	1,052,109	14.8	8.9%
2021	7,848	288	34	(254)	97	2,558	2,461	7,244	347,477	1,094,677	15.1	8.3%
2022	7,903	288	34	(254)	105	2,316	2,211	7,294	349,845	1,121,822	15.4	7.7%
2023	7,957	288	34	(254)	282	1,539	1,257	7,344	350,647	1,167,402	15.9	7.3%
2024	8,012	289	34	(255)	158	1,962	1,804	7,395	355,938	1,182,117	16.0	6.8%
2025	8,069	288	34	(254)	207	1,811	1,604	7,447	368,701	1,213,578	16.3	6.4%
2026	8,125	288	34	(254)	148	2,015	1,867	7,500	377,102	1,238,030	16.5	6.1%
2027	8,186	288	34	(254)	333	1,827	1,494	7,558	367,215	1,279,379	16.9	5.8%
2028	8,248	289	34	(255)	185	1,935	1,749	7,613	369,382	1,297,938	17.0	5.5%
2029	8,300	288	34	(254)	219	1,711	1,492	7,661	399,077	1,335,665	17.4	5.3%
2030	8,361	288	34	(254)	552	1,659	1,107	7,717	406,645	1,379,748	17.9	5.2%
2031	8,420	288	34	(254)	212	1,663	1,451	7,772	414,203	1,404,124	18.1	5.0%
2032	8,483	289	34	(255)	147	1,843	1,696	7,830	421,901	1,432,235	18.3	4.8%
2033	8,540	288	34	(254)	184	1,833	1,649	7,883	429,743	1,471,569	18.7	4.7%
2034	8,601	288	34	(254)	484	1,460	976	7,938	437,730	1,524,203	19.2	4.6%
2035	8,665	288	34	(254)	232	1,455	1,223	7,998	445,866	1,553,215	19.4	4.5%
2036	8,729	289	34	(255)	228	1,469	1,241	8,057	454,153	1,578,574	19.6	4.3%
2037	8,792	288	34	(254)	201	1,634	1,433	8,115	462,594	1,611,566	19.9	4.2%
2038	8,860	288	34	(254)	212	1,371	1,159	8,178	471,191	1,650,916	20.2	4.1%
2039	8,929	288	34	(254)	203	1,483	1,280	8,242	479,949	1,686,576	20.5	4.0%
2040	8,959	289	34	(255)	247	1,370	1,123	8,306	488,869	2,191,443	26.4	4.8%

	East Reserve Margin - MW: Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,222	1,118		0	1,118	-8.5%
2012	1,264	1,318		0	1,318	4.3%
2013	1,273	1,320		0	1,320	3.7%
2014	1,251	1,390		0	1,390	11.1%
2015	1,240	1,367		0	1,367	10.3%
2016	1,223	1,361		0	1,361	11.3%
2017	1,211	1,367		0	1,367	12.9%
2018	1,216	1,366		0	1,366	12.3%
2019	1,222	1,113	1 - 407 MW CC.	407	1,520	24.4%
2020	1,225	1,113		407	1,520	24.1%
2021	1,236	1,128		407	1,535	24.2%
2022	1,244	1,128		407	1,535	23.4%
2023	1,246	1,128		407	1,535	23.2%
2024	1,253	1,128		407	1,535	22.5%
2025	1,266	1,128		407	1,535	21.2%
2026	1,276	1,128		407	1,535	20.3%
2027	1,287	1,128		407	1,535	19.3%
2028	1,295	1,128		407	1,535	18.5%
2029	1,301	1,128		407	1,535	18.0%
2030	1,311	1,128		407	1,535	17.1%
2031	1,322	1,128		407	1,535	16.1%
2032	1,330	1,128		407	1,535	15.4%
2033	1,344	1,120		407	1,527	13.6%
2034	1,348	1,120		407	1,527	13.3%
2035	1,359	1,124		407	1,531	12.6%
2036	1,367	1,124		407	1,531	12.0%
2037	1,384	1,124		407	1,531	10.6%
2038	1,397	1,124		407	1,531	9.6%
2039	1,409	1,124		407	1,531	8.6%
2040	1,420	1,124		407	1,531	7.8%

* Total East SO2 Excludes Cardinal 2&3 Emissions

[a] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's

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KENTUCKY POWER COMPANY
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Costs and Emissions Summary
Big Sandy 2, Reference Prime Commodity Pricing, Path A, FGD Case 5 with CCR Related Costs Included

Optimal Plan Cost Summary ($000)

Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Base Rate Impacts: Carrying Charges (E)	Base Rate Impacts: Incremental O&M (F)	Base Rate Impacts: Total (G)=(E)+(F)	Total Cost (H)=(D)+(G)	Market Value of Allowances Consumed (I)	Grand Total (J)=(H)+(I)	Value of ICAP (K)	Grand Total (L)=(J)-(K)	CPW (M)	Capital Expenditures (N)
2011	206,672	(12,550)	36,673	182,549	0	0	0	182,549	7,502	190,052	0	190,052	190,052	0
2012	247,622	(21,002)	79,638	188,985	0	0	0	188,985	5,884	194,870	0	194,870	369,424	0
2013	243,457	(30,815)	45,053	229,242	0	0	0	229,242	47,904	277,146	0	277,146	604,241	0
2014	276,558	(33,494)	66,039	248,923	0	0	0	248,923	75,687	324,610	368	324,242	857,113	0
2015	283,796	(42,680)	65,727	260,757	0	0	0	260,757	97,046	357,804	251	357,553	1,113,786	0
2016	266,672	(44,808)	80,753	230,803	126,092	77,411	203,503	434,310	20,364	454,674	1,259	453,414	1,413,359	126,092
2017	250,479	(45,333)	91,410	204,463	137,468	86,285	223,753	428,215	160,026	588,242	3,356	584,885	1,769,139	137,468
2018	271,070	(45,671)	137,421	179,321	141,054	104,266	245,320	424,641	167,334	591,974	3,776	588,199	2,098,432	141,054
2019	317,759	(41,473)	176,927	182,305	246,358	110,701	357,059	539,364	169,952	709,316	15,196	694,119	2,455,130	246,358
2020	328,279	(43,420)	180,260	191,447	252,035	111,386	363,421	554,868	180,192	735,060	17,242	717,818	2,796,621	252,035
2021	337,213	(57,789)	186,709	208,291	257,855	114,818	372,673	580,964	181,709	762,673	19,670	743,003	3,121,031	257,855
2022	338,609	(59,235)	170,895	226,948	263,818	116,524	380,342	607,289	179,565	786,854	20,839	766,015	3,476,665	263,818
2023	318,686	(61,516)	108,019	272,183	269,928	115,207	385,135	657,318	162,076	819,394	22,454	796,940	3,723,703	269,928
2024	343,001	(61,248)	149,859	254,990	276,191	123,361	399,552	654,542	178,015	832,557	23,243	809,313	3,999,284	276,191
2025	348,880	(62,326)	135,824	275,382	282,611	122,860	405,471	680,853	176,609	857,462	22,935	834,526	4,200,851	282,611
2026	366,265	(63,232)	158,794	270,703	289,190	130,812	420,002	690,705	185,712	876,417	22,734	853,683	4,507,143	289,190
2027	364,259	(64,135)	132,825	295,569	295,934	130,234	426,168	721,738	181,406	903,144	22,106	881,038	4,741,112	295,934
2028	381,131	(64,855)	156,127	289,859	302,844	138,540	441,384	731,243	190,660	921,903	21,151	900,752	4,961,293	302,844
2029	379,103	(65,526)	138,213	307,416	309,930	141,741	451,671	759,086	188,814	947,900	20,465	927,432	5,169,966	309,930
2030	380,741	(66,258)	108,028	338,971	317,192	139,972	457,164	796,135	182,730	978,865	19,099	959,767	5,368,740	317,192
2031	396,153	(69,101)	135,554	329,700	324,635	149,885	474,520	804,220	194,028	998,248	17,530	980,718	5,555,701	324,635
2032	417,740	(67,027)	161,239	325,528	332,266	154,024	486,290	811,818	205,197	1,017,016	16,416	1,000,599	5,731,291	332,266
2033	428,406	(70,145)	160,009	338,541	340,089	158,424	498,513	837,054	207,858	1,044,912	13,030	1,031,883	5,897,958	340,089
2034	417,144	(71,029)	103,563	384,610	348,108	155,979	504,087	888,697	194,771	1,083,468	12,508	1,070,960	6,057,174	348,108
2035	431,767	(74,163)	125,967	379,963	356,330	166,914	523,244	903,207	204,409	1,107,617	11,407	1,096,210	6,207,101	356,330
2036	434,509	(75,100)	129,129	380,481	364,757	168,908	533,665	914,146	209,157	1,123,303	10,156	1,113,147	6,347,410	364,757
2037	453,025	(75,611)	148,923	379,714	373,399	172,122	545,521	925,235	218,781	1,144,015	7,292	1,136,723	6,479,212	373,399
2038	450,457	(78,195)	126,795	401,857	382,259	171,850	554,109	955,966	216,457	1,172,423	5,069	1,167,353	6,603,801	382,259
2039	465,701	(73,007)	133,774	404,434	391,342	176,262	567,604	972,038	224,256	1,196,294	2,972	1,193,322	6,721,032	391,342
2040	471,247	(80,571)	126,348	425,470	400,655	637,017	1,037,672	1,463,142	223,343	1,686,485	1,006	1,685,479	6,873,445	400,655
2011 Net Present Value														
Period of 2011-2040	3,530,173	(534,316)	1,250,729	2,813,760	1,845,329	920,768	2,766,096	5,579,857	1,396,382	6,976,239	102,794	6,873,445		
Base Case O&M 2011-2040							613,497			613,497	0	613,497		
Utility Cost Present Value 2011-2040							3,379,594			7,589,736	102,794	7,486,942		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	39	183
2015	28	175
2016	49	496
2017	69	941
2018	62	1,174
2019	203	1,397
2020	206	1,610
2021	209	1,812
2022	200	2,003
2023	199	2,181
2024	193	2,348
2025	176	2,501
2026	166	2,641
2027	154	2,767
2028	145	2,805
2029	139	2,841
2030	128	2,875
2031	116	2,910
2032	107	2,945
2033	84	2,980
2034	80	3,016
2035	72	3,052
2036	63	3,089
2037	45	3,126
2038	31	3,163
2039	18	3,201
2040	6	3,240

DRAF

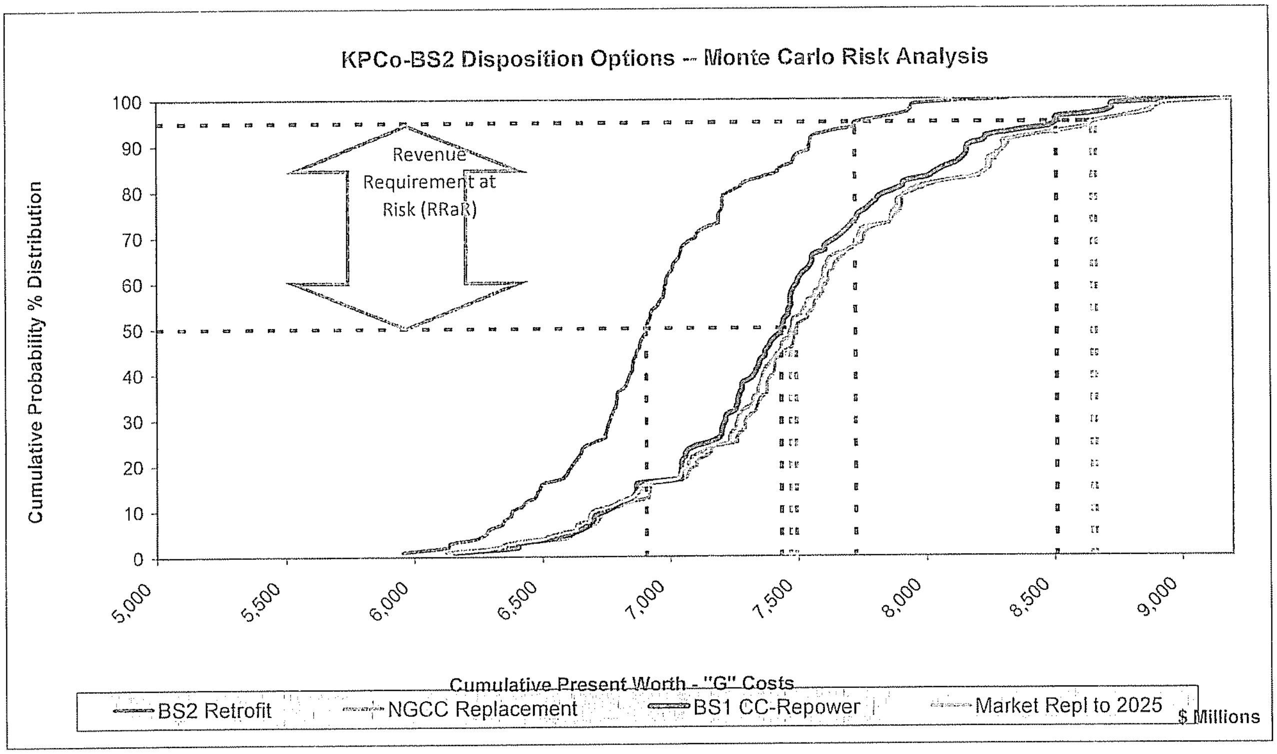
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Big Sandy 2, Reference Prime Commodity Pricing, Path A, FGD Case 5 with CCR Related Costs Included

	SO2 Emissions Total East[a]	NSR SO2 NSR Adjusted Total[b]	NSR SO2 Caps	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	0	52,559	450,000	397,441	7,468	6,319	0.29
2012	0	59,019	414,000	354,981	8,315	6,872	0.34
2013	0	51,289	344,000	292,711	7,431	6,226	0.25
2014	0	54,334	334,000	279,666	7,716	5,492	0.30
2015	0	52,260	269,000	216,740	7,745	5,589	0.30
2016	0	14,618	254,000	239,382	7,919	4,886	0.31
2017	0	14,947	229,000	214,053	7,799	4,860	0.31
2018	0	16,601	178,000	161,399	8,434	5,605	0.33
2019	3	8,476	168,000	159,524	8,115	3,320	0.29
2020	3	4,705	168,000	163,295	8,173	1,644	0.28
2021	3	4,686	168,000	163,314	8,136	1,837	0.28
2022	3	4,503	168,000	163,497	7,939	1,768	0.26
2023	4	3,957	168,000	164,043	7,072	1,560	0.23
2024	3	4,466	168,000	163,534	7,668	1,731	0.26
2025	3	4,109	168,000	163,891	7,511	1,678	0.24
2026	3	4,491	100,000	95,509	7,796	1,755	0.27
2027	4	4,112	100,000	95,888	7,518	1,670	0.24
2028	3	4,501	100,000	95,499	7,798	1,797	0.27
2029	3	4,459	100,000	95,541	7,623	1,720	0.26
2030	4	3,952	100,000	96,048	7,290	1,622	0.23
2031	3	4,467	100,000	95,533	7,642	1,724	0.25
2032	3	4,543	100,000	95,457	7,980	1,799	0.27
2033	3	4,539	100,000	95,461	7,881	1,795	0.27
2034	4	3,976	100,000	96,024	7,384	1,643	0.23
2035	3	4,484	100,000	95,516	7,653	1,726	0.27
2036	3	4,509	100,000	95,491	7,732	1,744	0.27
2037	3	4,544	100,000	95,456	7,986	1,793	0.27
2038	3	4,511	100,000	95,489	7,801	1,759	0.27
2039	3	4,549	100,000	95,451	7,961	1,798	0.27
2040	3	4,537	100,000	95,463	7,848	1,767	0.27

	Summary of Energy Purchases and Sales (Gwh) Internal Requirements	Contract Purchases	Contract Sales	Net Contract Transactions	Market Purchases	Market Sales	Net Market Transactions	Internal Requirement 0.923 GWh	Est. Embedded Costs (G/T/D)	Grand Total (ALL COSTS)	TOTAL RATE IMPACT (cents / kWh)	TOTAL RATE IMPACT CAGR (thru)
2011	7,633	58	115	57	427	1,212	785	7,045	290,923	480,975	6.8	
2012	7,642	138	117	(22)	152	1,965	1,812	7,053	289,285	484,155	6.9	0.6%
2013	7,648	138	36	(102)	503	1,290	787	7,059	294,367	571,513	8.1	8.9%
2014	7,638	139	17	(122)	328	1,459	1,130	7,050	301,623	626,065	8.9	9.2%
2015	7,623	139	23	(116)	342	1,451	1,109	7,036	310,633	668,186	9.5	8.9%
2016	7,648	139	19	(120)	317	1,672	1,356	7,059	313,409	766,823	10.9	9.7%
2017	7,675	139	28	(111)	325	1,545	1,220	7,084	321,132	906,017	12.8	11.0%
2018	7,708	139	37	(102)	180	2,079	1,899	7,115	332,126	920,376	12.9	9.6%
2019	7,754	139	36	(103)	209	2,469	2,260	7,157	337,451	1,031,571	14.4	9.8%
2020	7,798	139	34	(105)	142	2,445	2,303	7,198	340,282	1,058,100	14.7	8.9%
2021	7,848	288	34	(254)	130	2,472	2,342	7,244	347,477	1,090,401	15.1	8.2%
2022	7,903	288	34	(254)	140	2,231	2,091	7,294	349,845	1,115,860	15.3	7.6%
2023	7,957	288	34	(254)	355	1,482	1,127	7,344	360,647	1,157,587	15.8	7.2%
2024	8,012	289	34	(255)	219	1,888	1,669	7,395	365,998	1,175,312	15.9	6.7%
2025	8,069	288	34	(254)	247	1,730	1,483	7,447	368,701	1,203,228	16.2	6.3%
2026	8,125	288	34	(254)	199	1,939	1,739	7,500	377,102	1,230,785	16.4	6.0%
2027	8,186	288	34	(254)	375	1,761	1,385	7,556	387,215	1,268,252	16.8	5.8%
2028	8,248	289	34	(255)	246	1,865	1,618	7,613	389,382	1,290,134	16.9	5.5%
2029	8,300	288	34	(254)	298	1,653	1,354	7,661	390,077	1,326,500	17.3	5.3%
2030	8,361	288	34	(254)	597	1,594	997	7,717	406,645	1,366,411	17.7	5.1%
2031	8,420	288	34	(254)	300	1,572	1,273	7,772	414,203	1,394,921	17.9	5.0%
2032	8,483	289	34	(255)	212	1,768	1,556	7,830	421,901	1,422,500	18.2	4.8%
2033	8,540	288	34	(254)	247	1,770	1,523	7,883	429,743	1,451,625	18.5	4.6%
2034	8,601	288	34	(254)	530	1,395	865	7,936	437,730	1,508,690	19.0	4.6%
2035	8,665	288	34	(254)	324	1,393	1,069	7,998	445,866	1,542,075	19.3	4.4%
2036	8,729	289	34	(255)	330	1,408	1,078	8,057	454,153	1,567,300	19.5	4.3%
2037	8,792	288	34	(254)	269	1,558	1,289	8,115	462,594	1,599,317	19.7	4.2%
2038	8,860	288	34	(254)	293	1,308	1,015	8,178	471,191	1,638,545	20.0	4.1%
2039	8,929	288	34	(254)	278	1,414	1,136	8,242	479,948	1,673,271	20.3	4.0%
2040	8,999	289	34	(255)	339	1,312	973	8,305	488,869	2,174,349	26.2	4.7%

	East Reserve Margin - MW Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,222	1,118		0	1,118	-8.5%
2012	1,264	1,318		0	1,318	4.3%
2013	1,273	1,320		0	1,320	3.7%
2014	1,251	1,390		0	1,390	11.1%
2015	1,240	1,367		0	1,367	10.3%
2016	1,223	1,370		0	1,370	12.0%
2017	1,211	1,377		0	1,377	13.7%
2018	1,216	1,376		0	1,376	13.1%
2019	1,222	1,122	1- 407 MW CC.	407	1,529	25.1%
2020	1,225	1,122		407	1,529	24.8%
2021	1,236	1,137		407	1,544	24.9%
2022	1,244	1,137		407	1,544	24.1%
2023	1,246	1,137		407	1,544	23.9%
2024	1,253	1,137		407	1,544	23.2%
2025	1,266	1,137		407	1,544	22.0%
2026	1,276	1,137		407	1,544	21.0%
2027	1,287	1,137		407	1,544	20.0%
2028	1,295	1,137		407	1,544	19.2%
2029	1,301	1,137		407	1,544	18.7%
2030	1,311	1,137		407	1,544	17.8%
2031	1,322	1,137		407	1,544	16.8%
2032	1,330	1,137		407	1,544	16.1%
2033	1,344	1,129		407	1,536	14.3%
2034	1,348	1,129		407	1,536	14.0%
2035	1,359	1,133		407	1,540	13.3%
2036	1,367	1,133		407	1,540	12.7%
2037	1,384	1,133		407	1,540	11.3%
2038	1,397	1,133		407	1,540	10.2%
2039	1,409	1,133		407	1,540	9.3%
2040	1,420	1,133		407	1,540	8.5%

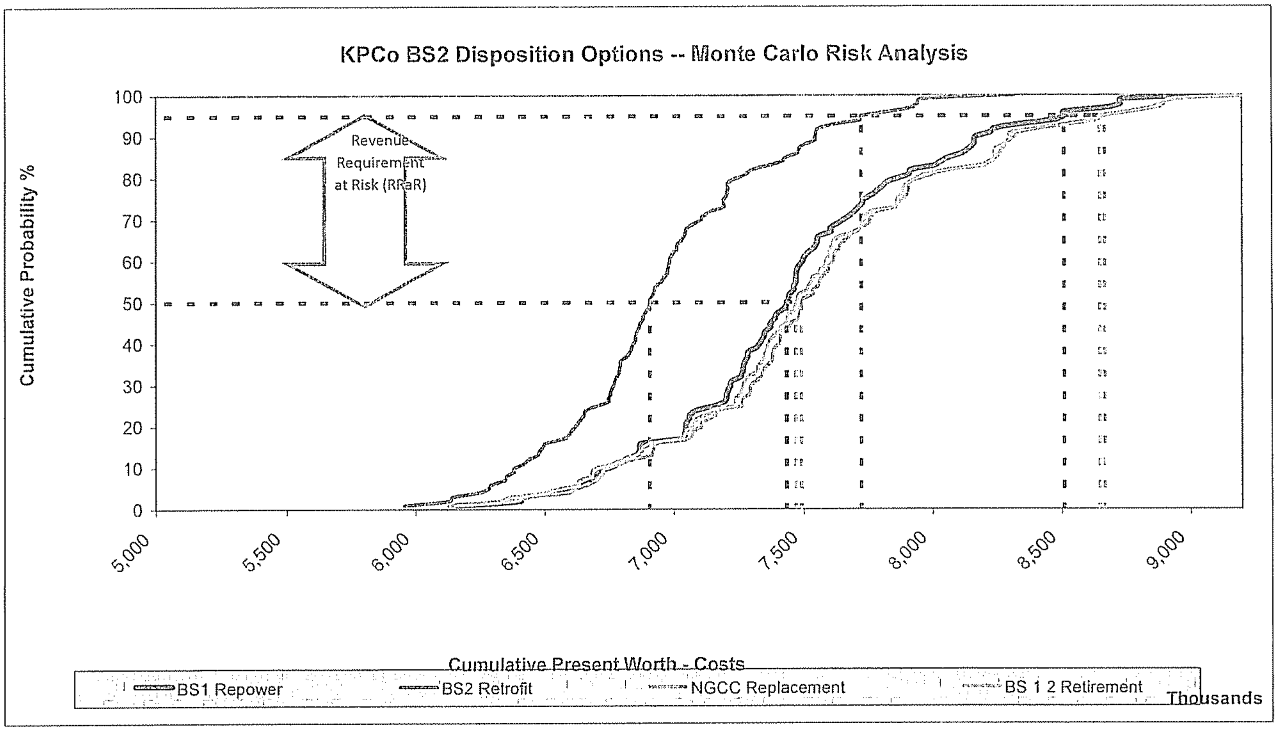
[a] Total East SO2 Excludes Cardinal 2&3 Emissions
[b] NSR Adjusted Total Includes Emissions for Cardinal 2&3, 780 MW Conesville 4, and excludes Beckjord, Stuart 1-4, Zimmer, all Gas Units, and IGCC's & PC's



	Cumul. Distribution Percentile	Option #1 BS2 Retrofit	Option #2 NGCC Replacement	Option #3 BS1 CC-Repower	Option #4B Market Repl to 2025	Delta Retrofit - NGCC	Delta Retrofit - Repower	Delta Retrofit - Mkt to 2025
CPW ($000)	50	6,907,015	7,492,590	7,433,656	7,469,125	(585,575) *-8.5%*	(526,641) *-7.6%*	(562,110) *-8.1%*
	95	7,722,158	8,666,036	8,508,691	8,647,851	(943,877) *-12.2%*	(786,532) *-10.2%*	(925,693) *-12.0%*
Relative Rank: *CPW*		1	4	2	3			
RRaR ($000)	*95th vs. 50th*	815,143	1,173,446	1,075,034	1,178,726	(358,303) *-44.0%*	(259,891) *-31.9%*	(363,583) *-44.6%*
Relative Rank: *RRaR*		1	3	2	4			

Simulated Outcomes -- Big Sandy 2 Retrofit (Option #1)

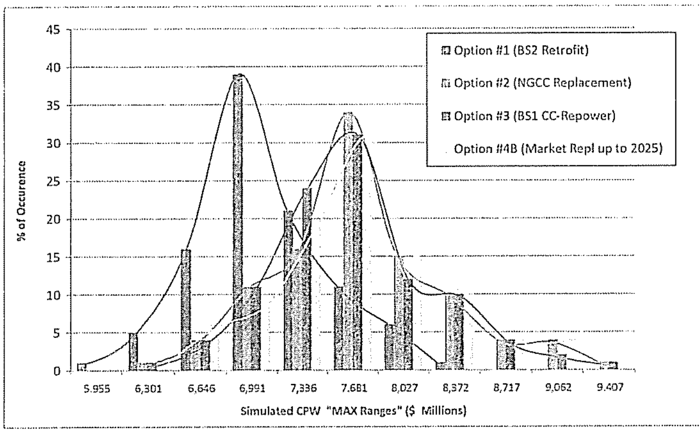
Key Risk Factor	All Outcomes Mean	RRaR-Exceeding Outcomes (>95%) Mean	Difference	%Diff	Year
Coal prices (nominal $/MMBtu)	2.59	3.03	0.43	16.7%	2020
Natural Gas Prices (nominal $/MMBtu)	8.62	10.22	1.59	18.5%	2025
Power Prices (nominal $/Mwh - All Hrs)	54.06	67.38	13.32	24.6%	2020
CO2 Emission Price/Tax ($/Tonne)	13.97	17.23	3.26	23.3%	2022
Load (Gwh)	9,208	11,284	2,076	22.5%	2020
FOM, Constr Costs / MW	4.99	5.44	0.45	9.0%	2025

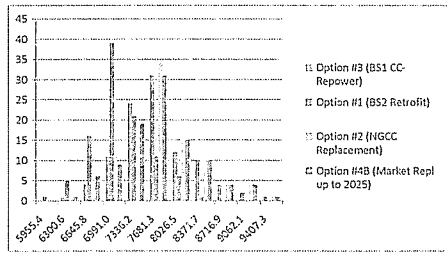


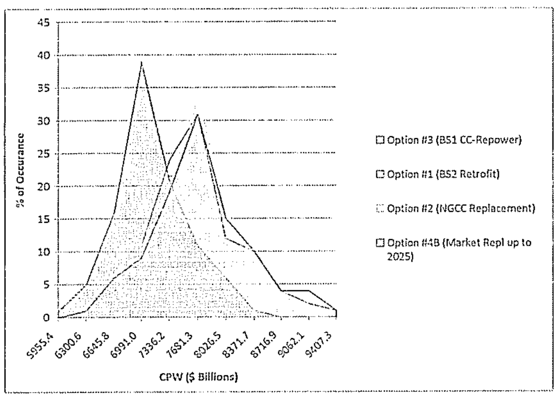
CPW ($000)	Cumul. Distribution Percentile	Option #1 BS2 Retrofit	Option #2 NGCC Replacement	Option #3 BS1 Repower	Option #4 BS 1 2 Retirement	Delta Retrofit - NGCC	Delta Retrofit - Repower	Delta Repower - NGCC
	50	6,907,015	7,492,590	7,433,656	7,469,125	(585,575)	(526,641)	(58,934)
						-8.5%	-7.6%	-0.8%
	68	7,051,550	7,720,241	7,603,446	7,718,014	(668,691)	(551,896)	(116,795)
						-9.5%	-7.8%	-1.5%
	95	7,722,158	8,666,036	8,508,691	8,647,851	(943,877)	(786,532)	(157,345)
						-12.2%	-10.2%	-1.8%
Relative Rank.	CPW	1	4	2	3			
RRaR ($000)								
+1.0 S.D.	68th vs. 50th	144,535	227,651	169,790	248,889	(83,116)	(25,254)	(57,861)
						-57.5%	-17.5%	-34.1%
+2.0 S.D.	95th vs. 50th	815,143	1,173,446	1,075,034	1,178,726	(358,303)	(259,891)	(98,411)
						-44.0%	-31.9%	-9.2%
Relative Rank:	RRaR	1	3	2	4			

Simulated outcomes - Market Plan					
Key Risk Factor	All Outcomes	RRaR-Exceeding Outcomes			Year
	Mean	Mean	Difference	%Diff	
Coal prices	2.59	3.03	0.43	16.7%	2020
Natural Gas Prices	8.62	10.22	1.59	18.5%	2025
Power Prices	54.06	67.38	13.32	24.6%	2020
CO2 Emission Price/Ta	13.97	17.23	3.26	23.3%	2022
Load	9,208	11,284	2,076	22.5%	2020
FOM, Constr Costs / M\	4.99	5.44	0.45	9.0%	2035

Bin		*Option #3 (BS1 CC-R*	Option #1 (B	Option #2 (N	Option #4B (	*3 (BS1 CC-R*	BS2 Retrofit	NGCC Repla	BS 1 2 Retirement
5,955.414	5955 4	0	1	0	0	0	1	0	0
6,300.600	6300 6	1	5	1	1	1	5	1	1
6.645.785	6645 8	4	16	4	6	4	16	4	6
6,990 971	6991 0	11	39	11	9	11	39	11	9
7.336.157	7336.2	24	21	16	19	24	21	16	19
7.681.342	7681 3	31	11	34	31	31	11	34	31
8.026.528	8026.5	12	6	15	15	12	6	15	15
8.371,714	8371 7	10	1	10	10	10	1	10	10
8.716.900	8716 9	4	0	4	4	4	0	4	4
9.062.085	9062.1	2	0	4	4	2	0	4	4
9.407.271	9407.3	1	0	1	1	1	0	1	1







Bin	*Frequency*
5,955,414	0
6,300,600	1
6,645,785	6
6,990,971	9
7,336,157	19
7,681,342	31
8,026,528	15
8,371,714	10
8,716,900	4
9,062,085	4
9,407,271	1
More	0

Risk Iteratic	BS1 Repower	BS2 Retrofit	NGCC Replac	BS 1 2 Retirement		
1	6,156,864	5,955,414	6,179,873	6,125,168	Min	5,955,414
2	6,400,740	6,126,525	6,367,733	6,318,149	max	9,407,271
3	6,407,011	6,138,910	6,428,533	6,362,318		
4	6,525,033	6,238,722	6,587,683	6,495,187		
5	6,606,511	6,277,660	6,618,075	6,556,595		
6	6,649,185	6,289,590	6,663,753	6,630,983		
7	6,680,681	6,338,966	6,699,442	6,631,584		
8	6,696,931	6,348,236	6,713,596	6,680,630		
9	6,704,292	6,376,578	6,727,194	6,680,777		
10	6,744,282	6,379,051	6,733,432	6,697,156		
11	6,779,057	6,416,669	6,792,944	6,755,735		
12	6,808,668	6,433,221	6,838,044	6,797,702		
13	6,850,711	6,468,217	6,913,406	6,844,447		
14	6,864,180	6,477,849	6,918,265	6,872,909		
15	6,867,778	6,489,518	6,922,716	6,883,505		
16	6,871,439	6,500,350	6,929,690	6,913,345		
17	7,041,537	6,569,547	7,051,236	7,019,035		
18	7,041,695	6,591,125	7,069,746	7,038,542		
19	7,043,956	6,602,533	7,077,237	7,051,749		
20	7,046,948	6,615,014	7,105,705	7,069,737		
21	7,048,162	6,628,853	7,107,158	7,075,095		
22	7,060,386	6,640,443	7,135,057	7,089,710		
23	7,063,229	6,651,368	7,162,725	7,128,721		
24	7,089,705	6,659,669	7,167,008	7,151,807		
25	7,153,773	6,697,881	7,260,483	7,226,435		
26	7,190,597	6,743,028	7,260,987	7,233,319		
27	7,201,726	6,745,598	7,269,419	7,236,569		
28	7,202,855	6,752,590	7,290,907	7,255,885		
29	7,207,909	6,757,035	7,294,244	7,259,266		
30	7,216,858	6,765,485	7,294,900	7,264,941		
31	7,219,564	6,770,187	7,312,802	7,268,804		
32	7,254,320	6,777,351	7,332,749	7,281,323		
33	7,260,537	6,786,621	7,338,850	7,311,524		
34	7,265,757	6,788,967	7,346,834	7,323,630		
35	7,266,871	6,791,940	7,358,616	7,324,204		
36	7,273,163	6,794,923	7,377,373	7,342,264		
37	7,281,593	6,816,987	7,378,999	7,345,172		
38	7,283,372	6,828,229	7,379,150	7,351,538		
39	7,314,671	6,835,656	7,385,865	7,355,849		
40	7,327,827	6,841,740	7,401,886	7,361,046		
41	7,336,848	6,850,951	7,407,999	7,367,036		
42	7,345,861	6,851,371	7,410,314	7,382,061		
43	7,350,683	6,856,109	7,410,954	7,399,474		
44	7,369,496	6,864,425	7,442,002	7,409,180		
45	7,369,658	6,869,695	7,449,798	7,427,261		
46	7,383,879	6,880,161	7,475,064	7,433,731		
47	7,391,727	6,882,467	7,482,030	7,437,714		
48	7,409,637	6,891,684	7,484,516	7,462,866		
49	7,429,353	6,903,046	7,484,539	7,463,243		
50	7,433,656	6,907,015	7,492,590	7,469,125		
51	7,439,916	6,909,004	7,498,834	7,475,448		
52	7,444,402	6,918,171	7,536,120	7,479,340		
53	7,459,406	6,924,581	7,536,479	7,510,074		
54	7,459,653	6,929,764	7,554,994	7,516,660		
55	7,469,667	6,949,606	7,562,647	7,528,518		
56	7,469,729	6,959,445	7,566,336	7,532,633		
57	7,470,201	6,973,279	7,582,433	7,560,747		
58	7,472,892	6,976,212	7,596,921	7,564,729		
59	7,482,711	6,979,941	7,597,120	7,584,163		
60	7,494,261	6,984,359	7,612,825	7,584,442		
61	7,501,203	6,987,101	7,618,701	7,594,566		

62	7,514,592	6,996,505	7,619,326	7,598,452
63	7,535,659	7,010,406	7,637,312	7,599,755
64	7,547,660	7,012,661	7,641,972	7,611,724
65	7,552,973	7,026,709	7,656,616	7,615,255
66	7,556,832	7,038,962	7,677,158	7,637,759
67	7,603,201	7,044,548	7,689,966	7,697,314
68	7,603,446	7,051,550	7,720,241	7,718,014
69	7,628,801	7,075,665	7,751,044	7,724,889
70	7,653,658	7,102,068	7,755,841	7,731,858
71	7,676,444	7,110,356	7,760,696	7,738,561
72	7,696,211	7,139,442	7,788,918	7,755,262
73	7,708,858	7,188,200	7,853,651	7,852,981
74	7,725,121	7,190,097	7,862,650	7,861,575
75	7,733,110	7,190,842	7,882,630	7,862,638
76	7,762,711	7,202,705	7,900,240	7,876,755
77	7,782,683	7,205,480	7,906,227	7,885,153
78	7,805,250	7,207,599	7,907,271	7,885,616
79	7,820,739	7,208,465	7,911,507	7,907,569
80	7,864,631	7,238,027	7,956,226	7,932,595
81	7,906,588	7,276,147	8,004,716	7,970,918
82	7,915,645	7,295,896	8,067,996	8,058,480
83	8,004,239	7,358,710	8,201,248	8,175,053
84	8,031,461	7,412,707	8,216,973	8,228,303
85	8,064,299	7,429,219	8,251,058	8,237,890
86	8,111,549	7,472,982	8,254,162	8,240,193
87	8,137,140	7,481,480	8,270,115	8,240,222
88	8,154,080	7,496,785	8,281,931	8,270,074
89	8,159,196	7,541,843	8,292,797	8,299,512
90	8,164,899	7,543,772	8,320,844	8,299,722
91	8,223,897	7,548,510	8,330,129	8,301,316
92	8,238,317	7,555,993	8,414,448	8,413,866
93	8,344,479	7,620,217	8,518,933	8,538,579
94	8,472,426	7,716,211	8,627,551	8,638,597
95	8,508,691	7,722,158	8,666,036	8,647,851
96	8,508,781	7,825,515	8,764,219	8,755,017
97	8,685,239	7,916,821	8,874,044	8,845,978
98	8,728,888	7,938,995	8,894,892	8,892,371
99	8,729,088	7,951,560	8,941,865	8,936,579
100	9,157,780	8,320,094	9,336,663	9,407,271

Bin 10
5,955,414
6300599.58
6645785.29
6990971.01
7336156.73
7681342.44
8026528.16
8371713.88
8716899.6
9062085.31
9407271.03

Kentucky Power
Annual Investment Carrying Charges
For Economic Analyses
As of 12/31/2010

	Investment Life (Years)		
	15	20	30
Return (WACC) (1)	**8.58**	**8.58**	**8.58**
Depreciation (2)	4.51	3.01	1.67
FIT (3) (4)	1.70	1.77	1.40
Property Taxes, General & Admin Expenses	1.78	1.78	1.78
	16.57	15.14	13.43

(1) Based on a 100% (as of 12/31/2010) and 0% incremental weighting of capital costs

(2) Sinking Fund annuity with R1 Dispersion of Retirements

(3) Assuming MACRS Tax Depreciation

(4) @ 35% Federal Income Tax Rate

ICAP Additions Reflected in PJM BRAs

(MW)	Delivery Year	CT/GT	Combined Cycle	Diesel	Hydro	Steam	Nuclear	Solar	Wind	Total	Total Thermal Only
New Capacity Units (ICAP MW)	2007/2008			18.7	0.3					19.0	
	2008/2009			27.0					66.1	93.1	
	2009/2010	399.5		23.8		53.0				476.3	
	2010/2011	283.3	580.0	23.0					141.4	1,027.7	
	2011/2012	416.4	1,135.0			704.8		1.1	75.2	2,332.5	
	2012/2013	403.8		7.8		621.3			75.1	1,108.0	
	2013/2014	329.0	705.0	6.0		25.0		9.5	245.7	1,320.2	
	Average-Annual	261.7	345.7	15.2	0.0	200.6	0.0	1.5	86.2	911.0	823.2
Capacity from Reactivated Units (ICAP MW)	2007/2008					47.0				47.0	
	2008/2009					131.0				131.0	
	2009/2010									0.0	
	2010/2011	160.0		10.7						170.7	
	2011/2012	80.0				101.0				181.0	
	2012/2013									0.0	
	2013/2014									0.0	
	Average-Annual	34.3	0.0	1.5	0.0	39.9	0.0	0.0	0.0	75.7	
Uprates to Existing Capacity Resources (ICAP MW)	2007/2008	114.5		13.9	80.0	235.6	92.0			536.0	
	2008/2009	108.2	34.0	18.0	105.5	196.0	38.4			500.1	
	2009/2010	152.2	206.0		162.5	61.4	197.4		16.5	796.0	
	2010/2011	117.3	163.0		48.0	89.2	160.3			577.8	
	2011/2012	369.2	148.6	57.4		186.8	292.1		8.7	1,062.8	
	2012/2013	231.2	164.3	14.2		193.0	126.0		56.8	785.5	
	2013/2014	56.4	59.0	0.3		215.0	47.0		39.6	417.3	
	Average-Annual	164.1	110.7	14.8	56.6	168.1	136.2	0.0	17.4	667.9	
Total		3,517.0	3,540.6	237.5	396.3	3,100.5	953.2	12.1	811.3	12,568.6	

Source: http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2013-2014-base-residual-auction-report.ashx
PJM DOCS #592585

SUMMARY

Kentucky Power Co.

Big Sandy Generating Unit Disposition Analysis

Life-Cycle (30-Year, 2011-2040) Economics

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS> .... vs. Option #1-*'BASE'*)

	UNIT DISPOSITION ALTERNATIVES				
KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	**Retrofit (2015)** [(A)] (D-FGD/CCR)	**Retrofit (2015)** (D-FGD/CCR)	**Retire (2015)** Repl w/Mkt to 2020, then CC	**Retire (2015)** Replace w/ ~800-MW CC	**Retire (2015)** Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	**Retrofit (2015)** (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario

$Millions

			Option #2	Option #3	Option #4	Option #5
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	**Path "A" ("No CO2 Policy")**		69	81	9
HIGH-Side Sensitivity		**Path "B"** (*All* Retire/Retrofit @1/2016)		(115)	30	(269)
BASE (ORIG)		**Path "A"**	195	(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [(C)]	**Path "A" ("Fleet Transition")**		(346)	(172)	(442)
LOW-Side Sensitivity		**Path "A" ("Lower Band")**		(498)	(369)	(617)

% (2016-2040)

			Option #2	Option #3	Option #4	Option #5
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	**Path "A" ("No CO2 Policy")**		1.3%	1.5%	0.2%
HIGH-Side Sensitivity		**Path "B"** (*All* Retire/Retrofit @1/2016)		-1.7%	0.4%	-3.9%
BASE (ORIG)		**Path "A"**	3.1%	-1.5%	0.4%	-2.2%
BASE (REV)	*Mar '11 Forecast* [(C)]	**Path "A" ("Fleet Transition")**		-5.5%	-2.7%	-7.0%
LOW-Side Sensitivity		**Path "A" ("Lower Band")**		-8.0%	-5.9%	-9.9%

(Levelized) $/MWh (2016-2040)

			Option #2	Option #3	Option #4	Option #5
CO2 Sensitivity	*Jan '11 Forecast* [(B)]	**Path "A" ("No CO2 Policy")**		1.4	1.7	0.2
HIGH-Side Sensitivity		**Path "B"** (*All* Retire/Retrofit @1/2016)		(2.4)	0.6	(5.5)
BASE (ORIG)		**Path "A"**	0.40	(2.0)	0.5	(2.8)
BASE (REV)	*Mar '11 Forecast* [(C)]	**Path "A" ("Fleet Transition")**		(7.1)	(3.5)	(9.1)
LOW-Side Sensitivity		**Path "A" ("Lower Band")**		(10.2)	(7.6)	(12.6)

[(A)] For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to 10 Years; recovery period for CC options remain at 30 Years

[(B)] (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast

[(C)] *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

Add'l Notes

- o "Retirement" options exclude costs associated w/ socio-economic impacts to the region
- o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)

SUMMARY

Kentucky Power Co.

Big Sandy Generating Unit Disposition Analysis

Life-Cycle (30-Year, 2011-2040) Economics

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS> .... vs. Option #1-'*BASE*')

UNIT DISPOSITION ALTERNATIVES

KPCo Unit	*BASE* Option #1	Option #2	Option #3	Option #4	Option #5
Big Sandy 2...	**Retrofit (2015)** [A] (D-FGD/CCR)	**Retrofit (2015)** (D-FGD/CCR)	**Retire (2015)** Repl w/Mkt to 2020, then CC	**Retire (2015)** Replace w/ ~800-MW CC	**Retire (2015)** Replace w/ BS1 Repower
Big Sandy 1...	Retire (2019) Replace w/ CC in 2019	**Retrofit (2015)** (D-FGD/CCR)	Retire (2019) Replace w/ CC in 2019	Retire (2019) Replace w/ CC in 2019	Repower as CC (2015) w/ Additional CC in 2020

Commodity Pricing Scenario			$Millions			
CO2 Sensitivity	*Jan '11 Forecast* [B]	Path "A" ("No CO2 Policy")		69	81	9
HIGH-Side Sensitivity		Path "B" (*All* Retire/Retrofit @1/2016)	195	(115)	30	(269)
BASE (ORIG)		Path "A"		(96)	26	(136)
BASE (REV)	*Mar '11 Forecast* [C]	Path "A" ("Fleet Transition")		(346)	(172)	(442)
LOW-Side Sensitivity		Path "A" ("Lower Band")		(498)	(369)	(617)

SENSITIVITY... Impact of a 5-Year Delay in CO2 Tax						
BASE (ORIG)	*Jan '11 Forecast* [B]	**Path "A"**			46	(83)
BASE (REV)	*Mar '11 Forecast* [C]	**Path "A" ("Fleet Transition")**			(152)	(390)

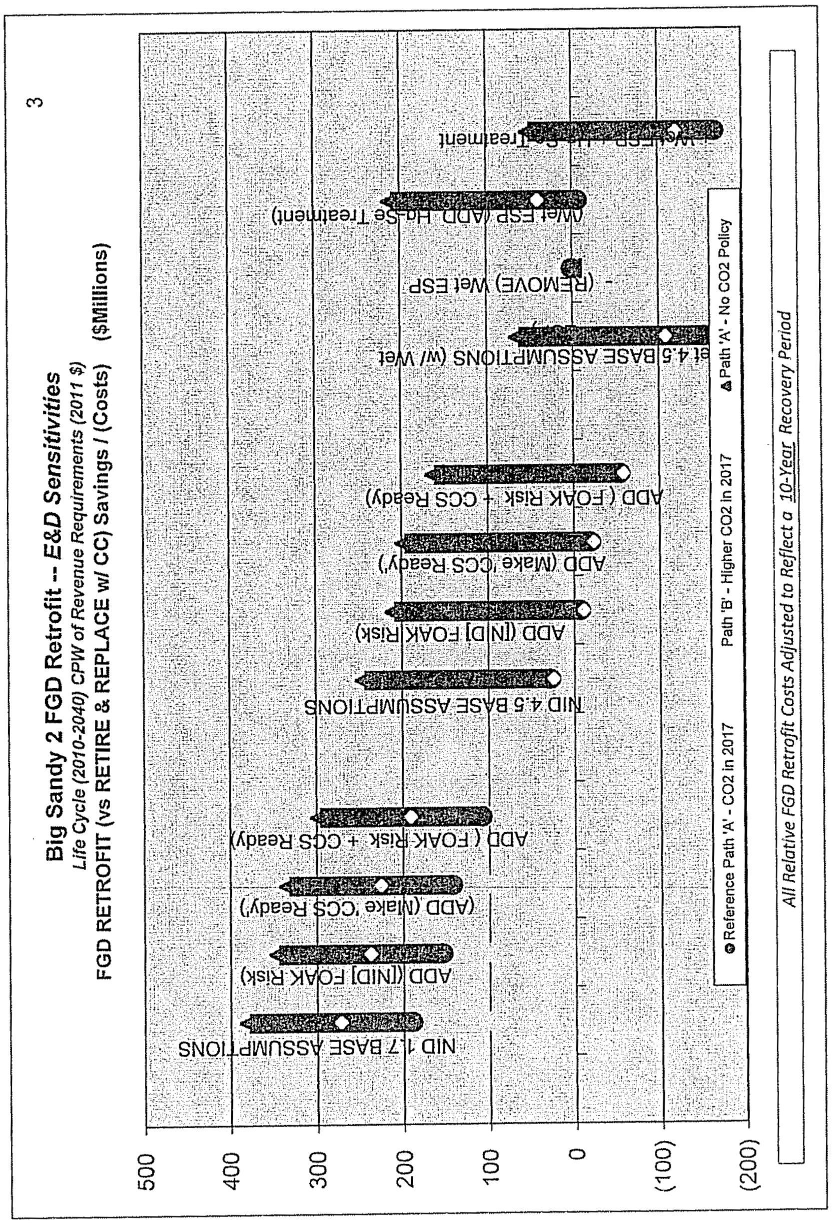
[A] For purpose of addressing future environmental-driven recovery risk, "Retrofit" option recovery period was accelerated to 10 Years; recovery period for CC options remain at 30 Years

[B] (Modified) "H2-10" AEP Fundamentals L/T commodity pricing forecast

[C] *Updated* "H2-10" AEP Fundamentals commodity pricing forecast to reflect emerging shale gas impacts

Add'l Notes

- o "Retirement" options exclude costs associated w/ socio-economic impacts to the region
- o "Retirement" options exclude costs associated w/ socio-economic impacts to the region basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
- o "G" Revenue Requirements established on a KPCo "stand-alone" (vs. AEP Pool) basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs inclusive of:
  1) All KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM and Capital (carrying charges); and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits and/or new-build or repowered NG-CCs)


Big Sandy 2 FGD Retrofit -- E&D Sensitivities
Life Cycle (2010-2040) CPW of Revenue Requirements (2011 $)
FGD RETROFIT (vs RETIRE & REPLACE w/ CC) Savings / (Costs) ($Millions)
3
500
400
300
200
100
0
(100)
(200)
NID 1.7 BASE ASSUMPTIONS
NID 4.5 BASE ASSUMPTIONS
Reference Path 'A' - CO2 in 2017
Path 'B' - Higher CO2 in 2017
Path 'A' - No CO2 Policy
All Relative FGD Retrofit Costs Adjusted to Reflect a 10-Year Recovery Period

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (March 2011) Load Forecast; WPCo Remains w/ OPCo
(2007/2008 - 2030/2031)

BASE ("Going-in") Capacity Position (i.e., No 'New (Thermal) Gen' post-Dresden) (HAPs) "PHASE-IN" Unit Retirements ('11 IRP Preliminary) & Retrofit Profile

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
		Obligation to PJM										Resources								KPCo Position (MW)	
														Planned Capacity Additions							
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Units	MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2010 /11	(k)	1,208	(1)	0	1,208	0	0.955	1.083	1,309	0	1,309	1,465	81				1,384	5.01%	1,315	6	6
2011 /12	(k)	1,218	(9)	0	1,218	0	0.955	1.083	1,320	0	1,320	1,470	104				1,366	6.26%	1,280	(40)	(40)
2012 /13	(k)	1,253	(18)	0	1,253	3	0.950	1.080	1,350	0	1,350	1,470	56				1,414	7.15%	1,313	(37)	(37)
2013 /14	(k)	1,283	(31)	0	1,283	12	0.957	1.080	1,374	0	1,374	1,470	45				1,425	7.38%	1,320	(54)	(54)
2014 /15	(k)	1,300	(44)	(2)	1,298	22	0.956	1.081	1,381	0	1,381	1,470	(6)				1,476	7.66%	1,363	(18)	(18)
2015 /16		1,268	(52)	(4)	1,264	31	0.956	1.081	1,334	0	1,334	1,445	(5)				1,450	7.67%	1,339	5	5
2016 /17		1,272	(57)	(7)	1,265	34	0.956	1.081	1,333	0	1,333	1,447	(7)				1,454	7.67%	1,342	9	9
2017 /18		1,276	(60)	(9)	1,268	37	0.956	1.081	1,332	0	1,332	1,447	(8)				1,455	7.72%	1,343	11	11
2018 /19		1,283	(62)	(10)	1,273	37	0.956	1.081	1,337	0	1,337	1,447	(8)				1,455	7.72%	1,343	6	6
2019 /20		1,291	(64)	(15)	1,276	37	0.956	1.081	1,340	0	1,340	1,169	(5)				1,174	7.28%	1,089	(251)	(251)
2020 /21		1,296	(65)	(18)	1,278	37	0.956	1.081	1,343	0	1,343	1,169	(4)				1,173	7.28%	1,088	(255)	(255)
2021 /22		1,310	(66)	(20)	1,290	37	0.956	1.081	1,356	0	1,356	1,169	(3)				1,172	7.28%	1,087	(269)	(269)
2022 /23		1,321	(66)	(21)	1,300	37	0.956	1.081	1,366	0	1,366	1,169	(2)				1,171	7.28%	1,086	(280)	(280)
2023 /24		1,327	(66)	(23)	1,304	37	0.956	1.081	1,371	0	1,371	1,169	(1)				1,170	7.28%	1,085	(286)	(286)
2024 /25		1,334	(65)	(23)	1,310	37	0.956	1.081	1,378	0	1,378	1,169	0				1,169	7.28%	1,084	(294)	(294)
2025 /26		1,347	(65)	(24)	1,323	37	0.956	1.081	1,392	0	1,392	1,169	0				1,169	7.35%	1,083	(309)	(309)
2026 /27		1,357	(65)	(23)	1,333	37	0.956	1.081	1,403	0	1,403	1,169	0				1,169	7.35%	1,083	(320)	(320)
2027 /28		1,367	(65)	(23)	1,344	37	0.956	1.081	1,414	0	1,414	1,169	0				1,169	7.35%	1,083	(331)	(331)
2028 /29		1,375	(66)	(23)	1,352	37	0.956	1.081	1,423	0	1,423	1,169	0				1,169	7.35%	1,083	(340)	(340)
2029 /30		1,385	(65)	(23)	1,361	37	0.956	1.081	1,433	0	1,433	1,169	0				1,169	7.35%	1,083	(350)	(350)
2030 /31		1,396	(65)	(23)	1,372	37	0.956	1.081	1,445	0	1,445	1,169	0				1,169	7.35%	1,083	(362)	(362)

Notes:
(a) Based on (March 2011) Load Forecast; WPCo Remains w/ OPCo (with implied PJM diversity factor)
Includes company MLR share of NCEMC

(b) Existing plus approved DR, EE, and IVV

(c) The impact of new DSM is delayed two years to represent either
(1) its impact on actual load feeding through the PJM load forecast process or
(2) verification prior to being offered into the PJM RPM auction.

(d) Demand Response approved by PJM in the prior planning year

(e) Installed Reserve Margin (IRM) = 15.0%(2007-2009), 15.5%(2010-2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
Wind Farm PPAs (Where Applicable)
EFFICIENCY IMPROVEMENTS:
2008/09: Rockport 1: 20 MW (turbine)
2009/10: Big Sandy 1: 0 MW (turbine)
2015/16: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

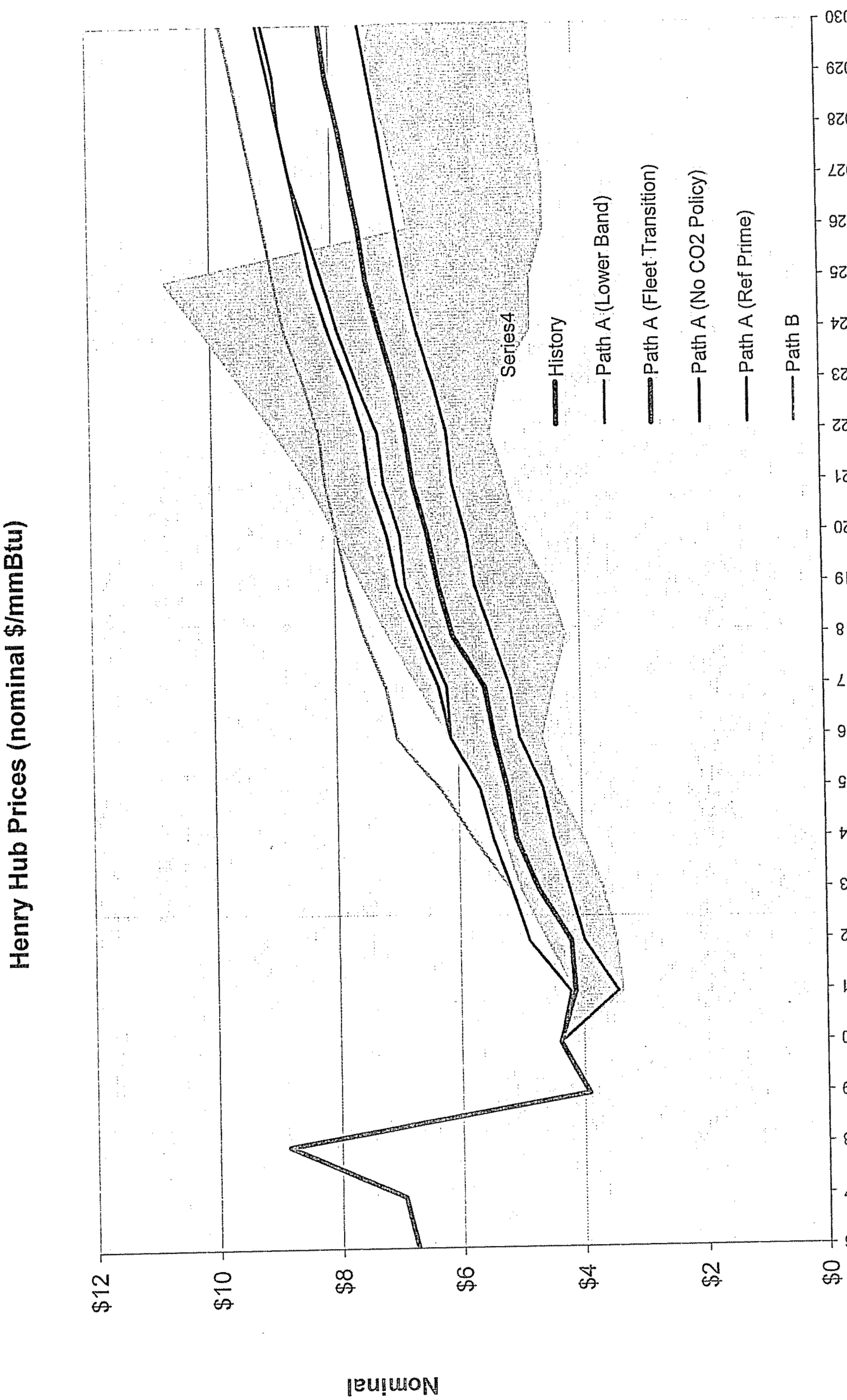
(g) continued
FGD DERATES:
2015/16: Big Sandy 2: 25 MW; Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
RETIREMENTS (Under a HAPs "PHASE-IN" assumption):
2019/20: Big Sandy 1

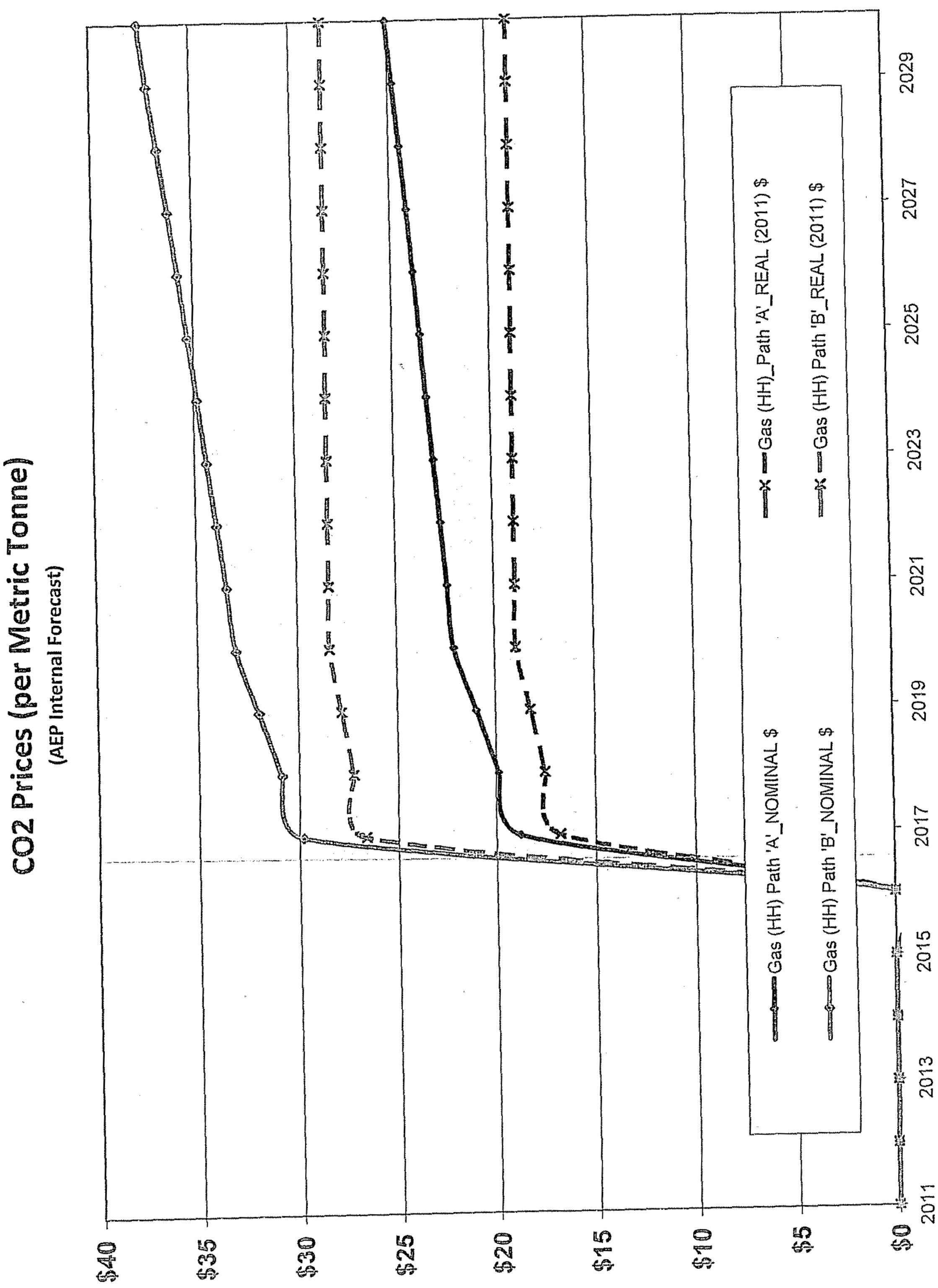
(h) Includes:
<Purchase> (from Constellation) of 315 MW in 2009/10-2011/12
Sale of 22 MW from Tanners Ck. 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2010/11-2012/13 (45 MW
RPM Auction Sales 2007/08 - 2013/14 (777, 1406, 1389, 1458, 1414, 696, 761) (M
3.6 MW capacity <credit> from SEPA's Philpot Dam via Blue Ridge contract
Estimated nominations for PJM EE ('passive' DR program) levels --reflected as a l
as part of PJM's emerging auction products (eff: 2014/15)

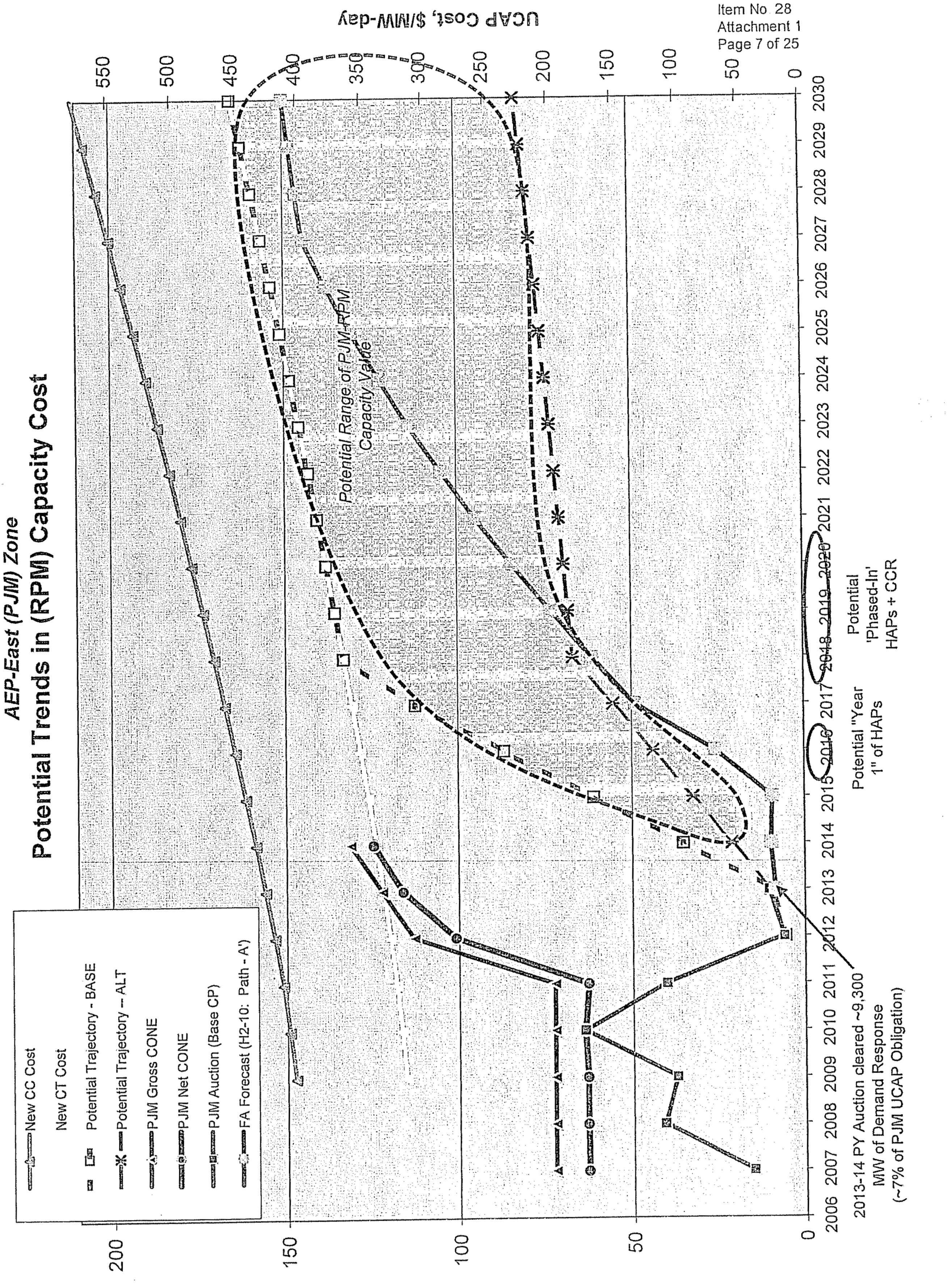
(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity
as of twelve months ended 9/30 of the previous year... Forecast represents latest Generation estir

(k) PJM latest forecast of AEP Zonal coincident peak demands (allocated to Operating Co. LSEs)


Henry Hub Prices (nominal $/mmBtu)
Nominal
$12
$10
$8
$6
$4
$2
$0
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
Series4
History
Path A (Lower Band)
Path A (Fleet Transition)
Path A (No CO2 Policy)
Path A (Ref Prime)
Path B


CO2 Prices (per Metric Tonne)
(AEP Internal Forecast)
$40
$35
$30
$25
$20
$15
$10
$5
$0
2011
2013
2015
2017
2019
2021
2023
2025
2027
2029
Gas (HH) Path 'A'_NOMINAL $
Gas (HH) Path 'B'_NOMINAL $
Gas (HH)_Path 'A'_REAL (2011) $
Gas (HH) Path 'B'_REAL (2011) $


AEP-East (PJM) Zone
Potential Trends in (RPM) Capacity Cost
New CC Cost
New CT Cost
Potential Trajectory - BASE
Potential Trajectory -- ALT
PJM Gross CONE
PJM Net CONE
PJM Auction (Base CP)
FA Forecast (H2-10: Path - A')
Potential Range of PJM RPM Capacity Value
ICAP Cost, $/kW-year
UCAP Cost, $/MW-day
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030
0 50 100 150 200
0 50 100 150 200 250 300 350 400 450 500 550
2013-14 PY Auction cleared ~9,300 MW of Demand Response (~7% of PJM UCAP Obligation)
Potential "Year 1" of HAPs
Potential 'Phased-In' HAPs + CCR

Big Sandy Unit 2 Major Environmental Capital Expenditure Estimates											
($Millions) *(post-Alloacted, excl. AFUDC)*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum:
RETROFITS											
FGD *(Per March LRP)*											
000009633 BS2 FGD Phase 2	5.7	38.3	81.4	145.6	122.8	13.1	-	-	-	-	401.2
000008348 Big Sandy FGD Landfill	1.5	1.7	7.3	10.1	10.1	8.6	0.1	-	-	-	37.9
BS002ASSC BS U2 FGD Associated	-	16.4	34.9	62.5	52.7	5.6	-	-	-	-	172.3
Total-FGD	**7.2**	**56.4**	**123.7**	**218.2**	**185.6**	**27.3**	**0.1**	**-**	**-**	**-**	**611.3**
CCR *(Per March LRP)*											
000019878 BS U2 Dry Fly Ash Conversion				-	-	-	-				-
000020353 BS U2 Bottom Ash Conversion				-	5.0	12.0	4.0	0.3	-	-	21.3
000020354 BS U2 Bottom Ash Ancillary Equ					-	-	-				-
000020356 BS U2 Ash WWT System			-	0.9	10.0	14.0	10.1	-	-	-	35.1
Total-CCR	-	-	-	**0.9**	**15.0**	**26.1**	**14.1**	**0.3**	**-**	**-**	**56.4**

(Generic) Combined Cycle Expenditure Estimates (768-MW)												
($Millions) *(post-Alloacted, excl. AFUDC)*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum:	
(Greenfield) CC *(per ERPI TAG)* *(2X1 GE-7G; 768-MW)*	-	16.8	69.1	354.0	453.5	0.0	0.0	0.0	-	-	893.5	
FOM											/kW-Yr	$19.00
VOM											/Mwh	$3.40

Big Sandy Unit 1 CC (2x1; GE-7FA; 640-MW) Repowering Estimates												
($Millions) *(post-Alloacted, excl. AFUDC)*	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum:	
BS1 Repowering *(per EP&FS prelim. estimate)* *(2X1 GE-7FA; 640-MW)*	-	8.4	34.4	175.3	223.5	-	-	-	-	-	441.6	
FOM											/kW-Yr	$25.88
VOM											/Mwh	$2.50

Kentucky Power Company

Capacity Resource Optimization

Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In") Commodity Pricing Including CCR-Related Costs

($000)

	Big Sandy 2 RETROFIT Alternatives							Big Sandy 2 RETIRE/REPLACE Alternatives							
Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 22 b *NID/Dry 1.7 lb* *BS1 Retire Accel.*	CASE 22 *NID 1.7 lb* ICAP Purch (MW)	CASE 23 * *NID/Dry 4.5 lb* 'BASE'	CASE 5 * *Dry 3.0 lb*	CASE 1 * *Wet 4.5 lb*	CASE 22 w/ BS1 FGD **	Retire & Repl - A *BS2 Replac w/* "Optimized" CC	Retire & Repl - B *BS2 Replac w/* "Like-Sized" CC	Retire & Repl - C *BS2 Replac w/ CC* Delay Retire by 4-Yr	Base Retire - ICAP *BS2 & BS1 Retire w/* *ICAP Purch (MW)*	Retire w/ ICAP+CC *BS2 Retire w/ ICAP thru '19* BS1&3 Repl w/ CC	Ret&BS1 Rpwr(+16-CC) *2x1 GEFA* +Add'l CC (2016) for RM	Ret&BS1 Rpwr(+20-CC) *2x1 GEFA* +Add'l CC (2020) for RM	Ret&BS1 Rpwr+ICAP *2x1 GEFA* +ICAP Purch (MW)
				OPTION #1			*OPTION #2*		*OPTION #4*			*OPTION #3*		*OPTION #5*	
2010 *thru* 2015	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)	BS2 Retirement 1-407 MW CC,	BS2 Retirement 1-768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 1-614 MW BS1 CCRepwr 1-407 MW CC	BS2 Retirement 1-614 MW BS1 RPWR, 329 MW ICAP	BS2 Retirement 1-614 MW CCRepwr
2016		BS1 Retirement 1-407 MW CC						1-645 MW CC							
2017											675	675		317 MW ICAP	317
2018											678	678		320 MW ICAP	320
2019	BS1 Retirement 1-407 MW CC		BS1 Retirement 195	BS1 Retirement 1-407 MW CC	BS1 Retirement 1-407 MW CC	BS1 Retirement 1-407 MW CC		BS1 Retirement	BS1 Retirement 1-407 MW CC,	BS2 Retirement 1-407 MW CC, BS1 Retirement 2-407 MW CC	BS1 Retirement 933	BS1 Retirement 3-407 MW CC		319 MW ICAP	319
2020 *thru* 2025			198								*Varies*			1-407 MW CC,	*Varies*
2026			239								973				373
2027			251				1-407 MW CC				985				371
2028			259								994				380
2029			265					1-407 MW CC		1-407 MW CC	1,000				386
2030			277								*Varies*		1-407 MW CC	1-407 MW CC,	*Varies*
2031			288								1,023				
2032 *thru* 2040			297								1,032				

(Life-Cycle) "G" REVENUE REQUIREMENT Summary:
(2011 $)

	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD	Base - A	Base - B	Base - C	BS2 Retires ICAP	BS2 Retires ICAP thru '19	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,259,447	$7,349,416	$7,111,098	$7,407,894	$7,519,599	$7,548,321	$7,475,814	$7,512,327	$7,607,801	$7,398,943	$6,487,552	$7,344,456	$7,378,358	$7,280,008	$7,002,751
Less: ICAP Revenue	$104,910	$117,082	($170,311)	$103,499	$102,794	$95,742	$141,015	$143,213	$129,285	$67,752	($727,425)	$98,236	$108,688	$60,477	($286,613)
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$7,164,637	$7,232,334	$7,289,550	$7,304,395	$7,416,805	$7,452,579	$7,334,799	$7,381,637	$7,478,516	$7,343,713	$7,309,779	$7,258,743	$7,269,671	$7,219,532	$7,289,364
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,347	$50,841	$56,332	$67,346	$55,151								
GRAND TOTAL - CPW -- Adj	$7,195,006	$7,272,803	$7,338,897	$7,355,236	$7,473,137	$7,519,925	$7,389,950								
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.17	9.27	9.35	9.37	9.52	9.58	9.42	9.40	9.53	9.36	9.31	9.25	9.26	9.20	9.28

Variances:

Cost / <Savings> vs. Retrofit w/ NID (4.6#)	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement (vs. Replace w/ CC)	ICAP + CC Replac (vs. Replace w/ CC)	BS1 Repower w/ Add'l CC ('16)	BS1 Repower w/ Add'l CC ('20)	BS1 Repower+ICAP
CPW	($148,447)	($58,478)	$296,796		$111,705	$140,427	$67,920	$104,433	$199,907	($8,952)	($920,342)	($63,438)	($29,536)	($127,886)	($405,144)
Less: ICAP Revenue	$1,410	$13,583	$273,810		($705)	($7,757)	$37,515	$39,713	$25,785	($35,747)	($830,925)	($5,263)	$5,108	($43,023)	($390,112)
Plus: Cost to Retire BS 1&2	$0	$0	($8,142)		$0	$0	$0	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	$1,494		$5,491	$16,505	$4,310	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($160,230)	($82,433)	$16,339		$117,901	$164,689	$34,714	$26,401	$123,280	($11,623)	($45,457)	($96,493)	($85,565)	($135,704)	($65,872)
% Variance	-2.2%	-1.1%	0.2%		1.6%	2.2%	0.5%	0.4%	1.7%	-0.2%	-0.6%	-1.3%	-1.2%	-1.8%	-0.9%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.20)	(0.11)			0.15	0.21	0.04	0.03	0.16	(0.01)	(0.06)	(0.12)	(0.11)	(0.17)	(0.08)

* These cases include Boiler modifications required to burn higher-sulfur coals

** Big Sandy 1 FGD costs do not include CCR related costs

*** All alternative KPCo relative economics above have also embedded the incremental costs associated with KPCo's current AEG 195-MW purchase entitlement share of both Rockport U1 and U2 (390-MW total), which was assumed to be fully-retrofitted eff: 12/2015 (U1); and 12/2019 (U2)

Kentucky Power Company

Capacity Resource Optimization

Expansion Plan Summary for '2H10 Reference' Commodity Pricing (Path B - EPA 'Accelerated') Including CCR Related Costs ($000)

	Big Sandy 2 RETROFIT Alternatives				Big Sandy 2 RETIRE/REPLACE Alternatives				
Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 23 * *NID/Dry 4.5 lb* OPTION #1	CASE 5 * *Dry 3.0 lb*	CASE 1 * *Wet 4.5 lb*	Retire & Repl - A *BS2 Replac w/ "Optimized" CC*	Retire & Repl - B *BS2 Replac w/ "Like-Sized" CC* OPTION #4	*Ret. & BS1 Repower 2x1 GEFA +Add'l CC in '16*	*Ret. & BS1 Repower 2x1 GEFA +Add'l CC in '20* OPTION #5	*Ret&BS1Rpwr+ICAP 2x1 GEFA +ICAP Purch (MW)*
2010 thru 2015					1- 407 MW CC, BS1&2 Retirement, 1 -645 MWCC	BS2 Retirement 1 -768 MW CC,	BS2 Retirement 1 -614 MW CCRepwr, 1- 407 MW CC	BS2 Retirement 1 -614 MW CCRepwr,	BS2 Retirement 1 -614 MW CCRepwr
2016	BS2 FGD (22), 1- 407 MW CC BS1 Retirement	BS2 FGD (23), 1- 407 MW CC, BS1 Retirement	BS2 FGD (5), 1- 407 MW CC, BS1 Retirement	BS2 FGD (1), 1- 407 MW CC, BS1 Retirement				317 MW ICAP 320 MW ICAP	
2017 + 2018						BS1 Retirement 1- 407 MW CC,		319 MW ICAP 1- 407 MW CC,	
2019									
2020					1- 407 MW CC		1- 407 MW CC	1- 407 MW CC,	
2021 thru 2028									
2029									
2030									
2031									
2032 thru 2040									

(Life-Cycle) REVENUE REQUIREMENT Summary:	CASE 22	CASE 23	CASE 5	CASE 1	Retire & Repl - A	Retire & Repl - B	Ret. & BS1 Rpwr CC-'16	Ret. & BS1 Rpwr CC-'20	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,766,634	$8,002,005	$8,156,883	$8,099,538	$8,041,933	$7,993,579	$7,884,560	$7,677,290	$7,570,563
Less : ICAP Revenue	$112,302	$111,141	$104,754	$110,560	$82,423	$128,802	$61,314	$4,321	-$231,814
Plus: Cost to Retire BS 1&2	$0	$0	$0	$0	$12,523	$0	$0	$0	$0
GRAND TOTAL - CPW	$7,654,331	$7,890,864	$8,052,129	$7,988,977	$7,972,033	$7,864,777	$7,823,246	$7,672,969	$7,802,377
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$50,841	$56,332	$67,346					
GRAND TOTAL - CPW -- Adj	$7,694,800	$7,941,705	$8,108,461	$8,056,323					
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.80	10.12	10.33	10.26	10.16	10.02	9.97	9.78	9.94

Variances: Cost / <Savings> vs. *Retrofit w/ NID (4.5#)*	CASE 22		CASE 5	CASE 1	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('L:ike-Sized' CC)	BS1 Repower w/ Add'l CC (2016)	BS1 Repower w/ Add'l CC (2020)	BS1 Repower+ICAP
CPW	($235,371)		$154,878	$97,533	$39,928	($8,426)	($117,445)	($324,715)	($431,442)
Less : ICAP Revenue	$1,161		($6,387)	($581)	($28,718)	$17,661	($49,827)	($106,821)	($342,955)
Plus: Cost to Retire BS 1&2	$0		$0	$0	$12,523	$0	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)		$5,491	$16,505	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($246,905)		$166,756	$114,618	$30,328	($76,928)	($118,459)	($268,736)	($139,328)
% Variance	-3.1%		2.1%	1.4%	0.4%	-1.0%	-1.5%	-3.4%	-1.8%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.31)		0.21	0.15	0.04	(0.10)	(0.15)	(0.34)	(0.18)

* These cases include Boiler modifications required to burn higher-sulfur coals

Kentucky Power Company

Capacity Resource Optimization

Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In"... NO [CO2] Policy) Commodity Pricing Including CCR-Related Costs

($000)

Big Sandy 2 RETROFIT Alternatives

Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 22 b *NID/Dry 1.7 lb* *BS1 Retire Accel.*	CASE 22 *NID 1.7 lb* ICAP Purch (MW)	CASE 23 * *NID/Dry 4.5 lb* OPTION #1	CASE 6 * *Dry 3.0 lb*	CASE 1 * *Wet 4.5 lb*	CASE 22 w/ BS1 FGD **
2010 *thru* 2015							
2016	BS2 FGD (22)	BS2 FGD (22) BS1 Retirement 1-407 MW CC	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)
2017							
2018							
2019	BS1 Retirement 1-407 MW CC		BS1 Retirement 195	BS1 Retirement 1-407 MW CC	BS1 Retirement 1-407 MW CC	BS1 Retirement 1-407 MW CC	
2020 *thru* 2026			186				
2027			251				1-407 MW CC
2028			259				
2029			266				
2030							
2031							
2032 *thru* 2040			277				
(Life-Cycle) REVENUE REQUIREMENT Summary:	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 6	CASE 1	Big Sandy 1 FGD
Cumul. Present Worth (CPW)(A)	$6,446,250	$6,546,621	$6,250,773	$6,567,338	$6,688,324	$6,722,856	$6,614,026
Less: ICAP Revenue	$84,512	$93,614	($117,476)	$83,475	$82,956	$77,769	$88,922
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0
GRAND TOTAL - CPW	$6,361,738	$6,453,008	$6,376,391	$6,483,863	$6,605,368	$6,645,088	$6,525,103
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,348	$50,841	$56,332	$67,346	$55,151
GRAND TOTAL - CPW -- Adj	$6,402,206	$6,493,476	$6,425,739	$6,534,704	$6,661,700	$6,712,432	$6,580,254
'Levelized (Life-Cycle) Cost' (cents/kWh)	8.16	8.27	8.19	8.33	8.49	8.55	8.38
Variances: *Cost / <Savings> vs. Retrofit w/ NID (4.5#)*	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 6	CASE 1	CASE 22 w/ BS1 FGD
CPW	($121,086)	($20,717)	($316,566)		$120,986	$155,517	$46,687
Less: ICAP Revenue	$1,037	$10,139	($200,951)		($519)	($5,706)	$5,447
Plus: Cost to Retire BS 1&2	$0	$0	$8,142		$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	($1,493)		$5,491	$16,505	$4,310
GRAND TOTAL - CPW -- Adj	($132,490)	($41,228)	$351,019		$126,996	$177,728	$45,549
% Variance	-2.0%	-0.6%	5.2%		1.9%	2.7%	0.7%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.17)	(0.05)	#REF!		0.16	0.23	0.06

Big Sandy 2 RETIRE/REPLACE Alts

Technology / Fuel Type (Sulfur Content)	Retire & Repl - A *BS2 Replac w/ "Optimized" CC*	Retire & Repl - B *BS2 Replac w/ "Like-Sized" CC* OPTION #4	Retire & Repl - C *BS2 Replac w/ CC* Delay Retire by 4-Yr	Base Retire - ICAP *BS2 Retire w/* ICAP Purch (MW)	Base Retire - ICAP+CC *BS2 Retire w/ ICAP* *BS1 ('19) Repl w/ CC* OPTION #3	Ret. & BS1 Repower *2x1 GEFA* +Add'l CC (2016) for RM	Ret. & BS1 Repower *2x1 GEFA* +Add'l CC (2020) for RM OPTION #5	Ret&BS1Rpwr+ICAP *2x1 GEFA* *+ICAP Purch (MW)*
2010 *thru* 2015								
2016	BS2 Retirement 1-407 MW CC, 1-645 MW CC	BS2 Retirement 1-768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 614 MW CCRepwr 1-407 MW CC	1-BS2 Retirement 614 MW BS1 RPWR, 329 MW ICAP	1- BS2 Retirement 1-614 MW CCRepwr 1-407 MW CC
2017				675	675		317 MW ICAP	317
2018				678	678		320 MW ICAP	320
2019	BS1 Retirement	BS1 Retirement 1-407 MW CC,	BS2 Retirement 1-407 MW CC, BS1 Retirement	BS1 Retirement 933	BS1 Retirement 3-407 MW CC		319 MW ICAP	319
2020 *thru* 2026			2-407 MW CC	933			1-407 MW CC	*Varies*
2027				985				371
2028				994				380
2029	1-407 MW CC		1-407 MW CC	1,000				386
2030						1-407 MW CC	1-407 MW CC	
2031								
2032 *thru* 2040				1,011				*Varies*
(Life-Cycle) REVENUE REQUIREMENT Summary:	Base - A	Base - B	Base - C	BS2 Retires ICAP	Base Retire - ICAP+CC	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	BS1 Repower+ICAP
Cumul. Present Worth (CPW)(A)	$6,855,164	$6,913,605	$6,716,396	$5,660,676	$6,670,180	$6,682,246	$6,571,817	$6,233,298
Less: ICAP Revenue	$90,929	$102,368	$122,169	-$527,243	$78,723	$66,223	$27,829	-$204,278
Plus: Cost to Retire BS 1&2	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$6,776,758	$6,811,237	$6,606,749	$6,282,920	$6,603,980	$6,616,022	$6,543,988	$6,437,576
Plus: Increm CPW for 10-yr FGD Recovery								
GRAND TOTAL - CPW -- Adj								
'Levelized (Life-Cycle) Cost' (cents/kWh)	8.63	8.68	8.42	8.00	8.41	8.43	8.34	8.20
Variances: *Cost / <Savings> vs. Retrofit w/ NID (4.5#)*	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement Savings/<Cost> (vs. Replace w/ CC)	Base Retire - ICAP+CC	BS1 Repower w/ Add'l CC ('16)	BS1 Repower w/ Add'l CC ('20)	BS1 Repower+ICAP
CPW	$287,826	$348,267	$149,057	($906,463)	$102,841	$114,907	$4,479	($334,040)
Less: ICAP Revenue	$7,454	$18,893	$38,694	($610,716)	($4,752)	($17,252)	($55,646)	($287,753)
Plus: Cost to Retire BS 1&2	$12,523	$0	$12,523	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	$242,054	$276,533	$72,045	($251,784)	$69,276	$81,318	$9,284	($97,128)
% Variance	3.7%	4.2%	1.1%	-3.9%	1.1%	1.2%	0.1%	-1.5%
'Levelized (Life-Cycle) Cost' (cents/kWh)	0.31	0.35	0.09	(0.32)	0.09	0.10	0.01	(0.12)

* These cases include Boiler modifications required to burn higher-sulfur coals

** Big Sandy 1 FGD costs do not include CCR related costs

KPSC Case No. 2011-00401
KIUC's First Set of Data Requests
Dated January 13, 2012
Item No. 28
Attachment 1
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Kentucky Power Company
Capacity Resource Optimization
Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In"[REV]–"FLEET TRANSITION") Commodity Pricing Including CCR-Related Costs
($000)

	Big Sandy 2 RETROFIT Alternative							Big Sandy 2 RETIRE/REPLACE Alternatives							
Technology / Fuel Type (Sulfur Content)	CASE 22 *NID/Dry 1.7 lb*	CASE 22 b *NID/Dry 1.7 lb*	CASE 22 *NID 1.7 lb*	CASE 23 * *NID/Dry 4.6 lb* *'BASE'*	CASE 5 * *Dry 3.0 lb*	CASE 1 * *Wet 4.6 lb*	CASE 22 w/ BS1 FGD **	Retire & Repl - A *BS2 Replac w/*	Retire & Repl - B *BS2 Replac w/*	Retire & Repl - C *BS2 Replac w/ CC*	Base Retire - ICAP *BS2 & BS1 Retire w/*	Retire w/ ICAP+CC *BS2 Retire w/ ICAP thru 2019*	Ret&BS1 Rpwr(+ 16-CC) *2x1 GEFA*	Ret&BS1 Rpwr(+ 20-CC) *2x1 GEFA*	Ret&BS1Rpwr+ICAP *2x1 GEFA*
		BS1 Retire Accel.	ICAP Purch (MW)					*"Optimized" CC*	*"Like-Sized" CC*	*Delay Retire by 4-Yr*	*ICAP Purch (MW)*	BS1&3 Repl w/ CC	+Add'l CC (2016) for RM	+Add'l CC (2020) for RM	+ICAP Purch (MW)
				OPTION #1	*OPTION #5*	*OPTION #6*	*OPTION #7*	*OPTION #8*	*OPTION #4*	*OPTION #10*	*OPTION #11*	*OPTION #3*		*OPTION #5*	
2010 *thru* 2015	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)	BS2 Retirement 1- 407 MW CC,	BS2 Retirement 1 -768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 1 -614 MW CCRepwr	BS2 Retirement 1-614 MW BS1 RPWR,	BS2 Retirement 1 -614 MW CCRepwr
2016		BS1 Retirement 1- 407 MW CC						1 -645 MW CC					1- 407 MW CC	329 MW ICAP	
2017											675	675		317 MW ICAP	317
2018											678	678		320 MW ICAP	320
2019	BS1 Retirement 1- 407 MW CC		BS1 Retirement 195	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC	BS1 Retirement 1- 407 MW CC		BS1 Retirement	BS1 Retirement 1- 407 MW CC,	BS2 Retirement 1- 407 MW CC, BS1 Retirement 2- 407 MW CC	BS1 Retirement 933	BS1 Retirement 3- 407 MW CC		319 MW ICAP	319
2020			198								*Varies*			1- 407 MW CC	319
2021 *thru* 2025											973				*Varies*
2026			239								985				373
2027			251				1- 407 MW CC				994				371
2028			259					1- 407 MW CC		1- 407 MW CC	1,000				380
2029			266								*Varies*				386
2030			277								1,023		1- 407 MW CC		*Varies*
2031			288								1,032				
2032 *thru* 2040			297												

(Life-Cycle) "G" REVENUE REQUIREMENT Summary:
(2011 $)

	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD	Base - A	Base - B	Base - C	BS2 Retires ICAP	BS2 Ret ICAP thru '19	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,259,447	$7,349,416	$7,111,098	$7,466,412	$7,518,599	$7,548,321	$7,475,814	$7,512,327	$7,370,903	$7,398,943	$6,487,552	$7,157,764	$7,378,358	$7,042,336	$7,002,751
Less: ICAP Revenue	$104,910	$117,082	($170,311)	$102,000	$102,794	$95,742	$141,015	$143,213	$127,823	$67,752	($727,425)	$100,601	$108,688	$69,552	($286,613)
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0	$0	$0	$0	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$7,154,537	$7,232,334	$7,289,550	$7,364,411	$7,416,805	$7,452,579	$7,334,799	$7,369,114	$7,243,080	$7,331,190	$7,309,779	$7,069,686	$7,269,671	$6,972,785	$7,289,364
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,347	$50,841	$56,332	$67,346	$55,151								
GRAND TOTAL - CPW -- Adj	$7,195,006	$7,272,803	$7,338,897	$7,415,252	$7,473,137	$7,519,925	$7,389,950								
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.17	9.27	9.35	9.45	9.52	9.58	9.42	9.39	9.23	9.34	9.31	9.01	9.26	8.88	9.29

Variances:

Cost / <Savings> vs. Retrofit w/ NID (4.5#)	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement (vs. Replace w/ CC)	ICAP + CC Replac (vs. Replace w/ CC)	BS1 Repower w/ Add'l CC (2016)	BS1 Repower w/ Add'l CC (2020)	BS1 Repower+ICAP
CPW	($206,965)	($116,996)	$355,314		$53,187	$81,909	$9,402	$45,915	($95,509)	($67,469)	($978,860)	($308,648)	($88,053)	($424,075)	($463,661)
Less: ICAP Revenue	$2,909	$15,082	$272,311		$794	($6,258)	$39,015	$41,212	$25,823	($34,248)	($829,426)	($1,399)	$6,687	($32,449)	($388,613)
Plus: Cost to Retire BS 1&2	$0	$0	($8,142)		$0	$0	$0	$0	$0	$0	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	$1,494		$5,491	$16,505	$4,310	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW -- Adj	($220,247)	($142,450)	$76,365		$57,885	$104,672	($25,303)	($46,138)	($172,173)	($84,062)	($105,474)	($345,667)	($145,582)	($442,468)	($126,889)
% Variance	-3.0%	-1.9%	1.0%		0.8%	1.4%	-0.3%	-0.6%	-2.3%	-1.1%	-1.4%	-4.7%	-2.0%	-6.0%	-1.7%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.28)	(0.18)			0.07	0.13	(0.03)	(0.06)	(0.22)	(0.11)	(0.13)	(0.44)	(0.19)	(0.56)	(0.16)

* These cases Include an incremental ~$172 MM capital spend associated with Boiler modifications required to burn higher-sulfur coals
** Big Sandy 1 FGD costs do not include CCR related costs
*** All alternative KPCo relative economics above have also embedded the incremental costs associated with KPCo's current AEG 195-MW purchase entitlement share of both Rockport U1 and U2 (390-MW total), which was assumed to be fully-retrofitted off: 12/2015 (U1); and 12/2019 (U2)

Kentucky Power Company

Capacity Resource Optimization

Expansion Plan Summary for '2H10 Reference' (Path A-"Phase-In"–"LOWER BAND") Commodity Pricing Including CCR-Related Costs

($000)

Big Sandy 2 RETROFIT Alternative

Technology / Fuel Type (Sulfur Content)	CASE 22 NID/Dry 1.7 lb	CASE 22 b NID/Dry 1.7 lb BS1 Retire Accel.	CASE 22 NID 1.7 lb ICAP Purch (MW)	CASE 23 * NID/Dry 4.5 lb 'BASE' OPTION #1	CASE 5 * Dry 3.0 lb OPTION #5	CASE 1 * Wet 4.5 lb OPTION #6	CASE 22 w/ BS1 FGD ** OPTION #7
2010 thru 2015	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (22)	BS2 FGD (23)	BS2 FGD (5)	BS2 FGD (1)	BS1 FGD BS2 FGD (22)
2016		BS1 Retirement 1-407 MW CC					
2017							
2018							
2019	BS1 Retirement 1-407 MW CC		BS1 Retirement 185	BS1 Retirement 1-407 MW CC	BS1 Retirement 1-407 MW CC	BS1 Retirement 1-407 MW CC	
2020			198				
2021 thru 2025							
2026			239				
2027			251				1-407 MW CC
2028			259				
2029			266				
2030			277				
2031			288				
2032 thru 2040			297				
(Life-Cycle) "G" REVENUE REQUIREMENT Summary: (2011 $)	CASE 22	CASE 22 b	CASE 22 ICAP	CASE 23	CASE 5	CASE 1	Big Sandy 1 FGD
Cumul. Present Worth (CPW)(A)	$7,259,447	$7,349,416	$7,111,098	$7,420,985	$7,519,599	$7,548,321	$7,475,814
Less: ICAP Revenue	$104,910	$117,082	($170,311)	$97,865	$102,794	$95,742	$141,015
Plus: Cost to Retire BS 1&2	$0	$0	$8,142	$0	$0	$0	$0
GRAND TOTAL - CPW	$7,154,537	$7,232,334	$7,289,650	$7,323,120	$7,416,805	$7,452,579	$7,334,799
Plus: Increm CPW for 10-yr FGD Recovery	$40,469	$40,469	$49,347	$50,841	$56,332	$67,346	$55,151
GRAND TOTAL - CPW – Adj	$7,195,006	$7,272,803	$7,338,997	$7,373,961	$7,473,137	$7,519,925	$7,389,950
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.17	9.27	9.35	9.39	9.52	9.56	9.42
Variances: Cost / <Savings> vs. Retrofit w/ NID (4.5#)	CASE 22	CASE 22 b	CASE 22 ICAP		CASE 5	CASE 1	CASE 22 w/ BS1 FGD
CPW	($161,538)	($71,569)	$309,887		$98,614	$127,336	$54,829
Less: ICAP Revenue	$7,045	$19,217	$268,175		$4,929	($2,123)	$43,150
Plus: Cost to Retire BS 1&2	$0	$0	($8,142)		$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($10,372)	($10,372)	$1,494		$5,491	$16,505	$4,310
GRAND TOTAL - CPW – Adj	($178,956)	($101,159)	$36,064		$99,176	$145,963	$16,988
% Variance	-2.4%	-1.4%	0.5%		1.3%	2.0%	0.2%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.23)	(0.13)			0.13	0.19	0.02

Big Sandy 2 RETIRE/REPLACE Alternatives

Technology / Fuel Type (Sulfur Content)	Retire & Repl - A BS2 Replac w/ "Optimized" CC OPTION #8	Retire & Repl - B BS2 Replac w/ "Like-Sized" CC OPTION #4	Retire & Repl - C BS2 Replac w/ CC Delay Retire by 4-Yr OPTION #10	Base Retire - ICAP BS2 & BS1 Retire w/ ICAP Purch (MW) OPTION #11	Retire w/ ICAP+CC BS2 Retire w/ ICAP thru 2019 BS1&3 Repl w/ CC OPTION #3	Ret&BS1 Rpwr(+ 16-CC) 2x1 GEFA +Add'l CC (2016) for RM	Ret&BS1 Rpwr(+ 20-CC) 2x1 GEFA +Add'l CC (2020) for RM OPTION #5	Ret&BS1Rpwr+ICAP 2x1 GEFA +ICAP Purch (MW)
2010 thru 2015 / 2016	BS2 Retirement 1-407 MW CC, 1-645 MW CC	BS2 Retirement 1-768 MW CC		BS2 Retirement 687	BS2 Retirement 687	BS2 Retirement 1-614 MW CCRepwr 1-407 MW CC	BS2 Retirement 1-614 MW BS1 RPWR, 329 MW ICAP	BS2 Retirement 1-614 MW CCRepwr
2017				675	675		317 MW ICAP	317
2018				678	678		320 MW ICAP	320
2019	BS1 Retirement	BS1 Retirement 1-407 MW CC,	BS2 Retirement 1-407 MW CC, BS1 Retirement	BS1 Retirement 933	BS1 Retirement 3-407 MW CC		319 MW ICAP	319
2020			2-407 MW CC	Varies			1-407 MW CC	319
2021 thru 2025								Varies
2026				973				373
2027				985				371
2028				994				380
2029	1-407 MW CC		1-407 MW CC	1,000				386
2030				Varies				Varies
2031				1,023		1-407 MW CC		
2032 thru 2040				1,032				
(Life-Cycle) "G" REVENUE REQUIREMENT Summary: (2011 $)	Base - A	Base - B	Base - C	BS2 Retires ICAP	BS2 Ret ICAP thru '19	Ret&BS1 Rpwr(+ 16-CC)	Ret&BS1 Rpwr(+ 20-CC)	Ret&BS1Rpwr+ICAP
Cumul. Present Worth (CPW)(A)	$7,512,327	$7,126,654	$7,398,943	$6,487,552	$6,960,281	$7,378,358	$6,815,225	$7,002,751
Less: ICAP Revenue	$143,213	$121,919	$67,752	($727,425)	$96,663	$108,688	$58,749	($286,613)
Plus: Cost to Retire BS 1&2	$0	$0	$0	$94,802	$12,523	$0	$0	$0
GRAND TOTAL - CPW	$7,369,114	$7,004,735	$7,331,190	$7,309,779	$6,876,141	$7,269,671	$6,756,476	$7,289,364
Plus: Increm CPW for 10-yr FGD Recovery								
GRAND TOTAL - CPW – Adj								
'Levelized (Life-Cycle) Cost' (cents/kWh)	9.39	8.92	9.34	9.31	8.76	9.26	8.61	9.29
Variances: Cost / <Savings> vs. Retrofit w/ NID (4.5#)	Retire & Repl - A ('Optimized' CC)	Retire & Repl - B ('Like-Sized' CC)	Retire - C (Delay Retire 4-Yrs)	ICAP Replacement (vs. Replace w/ CC)	ICAP + CC Replac (vs. Replace w/ CC)	BS1 Repower w/ Add'l CC (2016)	BS1 Repower w/ Add'l CC (2020)	BS1 Repower+ICAP
CPW	$91,342	($294,331)	($22,042)	($933,433)	($460,704)	($42,627)	($605,760)	($418,234)
Less: ICAP Revenue	$45,348	$24,054	($30,112)	($825,290)	($1,202)	$10,823	($39,115)	($384,477)
Plus: Cost to Retire BS 1&2	$0	$0	$0	$94,802	$12,523	$0	$0	$0
Plus: Increm CPW for 10-yr FGD Recovery	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)	($50,841)
GRAND TOTAL - CPW – Adj	($4,847)	($369,226)	($42,771)	($64,183)	($497,820)	($104,291)	($617,406)	($84,598)
% Variance	-0.1%	-5.0%	-0.6%	-0.9%	-6.8%	-1.4%	-8.4%	-1.1%
'Levelized (Life-Cycle) Cost' (cents/kWh)	(0.01)	(0.47)	(0.05)	(0.08)	(0.63)	(0.13)	(0.78)	(0.11)

* These cases include an incremental ~$172 MM capital spend associated with Boiler modifications required to burn higher-sulfur coals

** Big Sandy 1 FGD costs do not include CCR related costs

*** All alternative KPCo relative economics above have also embedded the incremental costs associated with KPCo's current AEG 195-MW purchase entitlement share of both Rockport U1 and U2 (390-MW total), which was assumed to be fully-retrofitted eff: 12/2015 (U1); and 12/2019 (U2)

Kentucky Power Company
Big Sandy EPA Impact Analysis
End Use Customer Rate Impact
($M)

	Capital Investment	Annual O&M	Revenue Percent Increase
Rockport FGD & SCR	212	8	6.41%
Big Sandy U2 FGD	839	49	28.69%
Big Sandy FGD plus Rockport	1,051	57	35.10%
Gas CC Brownfield	1,141	28	32.34%
Brownfield plus Rockport	1,353	36	38.75%
Gas Repower BSU1	1,063	28	30.46%
Repower plus Rockport	1,275	36	36.87%

Notes: Pool Capacity payments could increase by $50M for additonal shortfall of Kentucky Capacity in pool or market. Additonal revenue impact would be approximately 5%.

From: Daniel M Duellman on 02/23/2011 07:07 AM

To: Toby Thomas/AEPIN@AEPIN
cc: "Aaron Sink" <amsink@aep.com>, "Ashley Weaver" <amweaver@aep.com>, "John Torpey" <jftorpey@aep.com>, "Mark Becker" <mabecker@aep.com>, "Michael Isenberg" <misenberg@aep.com>, "Michael Wilkinson" <mlwilkinson@aep.com>, scweaver@aep.com, trfecho@aep.com, Scott Fisher/AEPIN@AEPIN, Patrick M Malone/AEPIN@AEPIN, Timothy V Riordan/FW1/AEPIN@AEPIN, Michael W Durner/OR2/AEPIN@AEPIN, Daniel H Drew/OR4/AEPIN@AEPIN
Subject: Re: Big Sandy Unit 1 CC Repower Cost and Performance Estimates

We made some minor revisions to the Powerpoint. Added a discussion about heat rate on slide 12, and updated plot plans on slides 7&8.

Dan Duellman
W: 614.716.1753
C: 614.554.0457
dmduellman@aep.com

Toby Thomas/AEPIN

02/22/2011 08:46 PM

To

scweaver@aep.com, "John Torpey" <jftorpey@aep.com>, "Mark Becker" <mabecker@aep.com>

cc

dmduellman@aep.com, trfecho@aep.com, "Ashley Weaver" <amweaver@aep.com>, "Aaron Sink" <amsink@aep.com>, "Michael Isenberg" <misenberg@aep.com>, "Michael Wilkinson" <mlwilkinson@aep.com>

Subject

Big Sandy Unit 1 CC Repower Cost and Performance Estimates

Scott/John/Mark:

Sorry for the late response as I missed by EOB commitment (technical difficulty with my BB).

The attached file contains the estimated capital repower costs and unit performance for two (2) options. The first option is a 1x1 MHI 501GAC at
about 480 MW (nominal - about 450 MW summer) and the second is a 2x1 GE 7FA.05 at about 640 MW (nominal - about 600 MW summer) - both include duct firing capability in order to maximize plant capacity given the fixed STG size. Both options result is similar $/kw costs. For this analysis, I would recommend using the 640 MW 2x1 option. In addition, the plant performance includes two modes: (1) full load without duct burners in operation and (2) with duct burners fully fired.

The cost and performance of converting the boilers to burn natural gas are included as well for your information.

The following O&M costs are based on our latest Dresden estimates and assume a stand alone CC plant (I made a couple of changes for items that would not apply at the BS site). If BS2 stays in operation, the incremental labor cost would be lower as we would only need the additional operations staff for the CC plant versus a full plant staff for the CC but this is a conservative approach. These costs are the same whether you use the 1x1 or
2x1 configuration mentioned above.

FOM: $7.8 MM/yr (in 2011$ - direct cost basis)
Annual Capital (PPB): $1.0 MM/yr
VOM: $2.50/MWh (this cost includes major outage costs for gas turbines and steam turbine)
Note: The VOM costs will consist of about 40% capital and 60% O&M based on our outage cost breakdown experience

Per FEL:
Use Henry Hub forecast * 1.05 (5% fuel retainage for the pipeline) + $0.40
(for pipeline transport costs).
NOTE: This fuel delivery cost and the included pipeline interconnect cost assumes we connect to the Tennesse Gas pipeline that is about 9 miles from the Big Sandy plant.

I also want to thank all of those folks that helped pull this information together in such short order.

Please let me know if you need more information or clarification.

Thanks

Toby

[attachment "BS Studies.ppt" deleted by Daniel M Duellman/OR2/AEPIN] BS StudiesA.ppt

From: Scott C Weaver on 04/07/2011 12:00 AM

To: Charles R Patton/AEPIN@AEPIN, Gregory G Pauley/OR3/AEPIN@AEPIN, Chris Potter/AEPIN@AEPIN, Ranie K Wohnhas/OR3/AEPIN@AEPIN, Toby Thomas/AEPIN@AEPIN

cc:

Subject: KPCo-Big Sandy_(Updated) Unit Disposition analysis

To offer some support to the modeling results just forwarded, this workbook contains some add'l supporting detail for the Big Sandy disposition analyses:

Big Sandy 2_Unit Disposition Alt Economics-REV8_040611.xls

I understand we have a progress review mtg set up for Fri AM. Perhaps we can take some time to go over some of these materials and address any questions you may have.

Scott C. Weaver
AEP Audinet: 200-1373
Outside: (614) 716-1373

From: Christian T Beam on 06/09/2011 01:23 PM
To: Scott C Weaver/OR4/AEPIN@AEPIN
cc:
Subject: Re: question/request

Scott we will be complete with our estimate at the end of July. We will provide you the data when complete.

From: Scott C Weaver
To: Christian Beam
Cc:
Date: 06/09/2011 12:10 PM CDT
Subject: question/request

Chris,

1) What timeframe has been communicated to Kentucky Power for the completion of the preliminary design/cost estimation effort for the Big Sandy 1 CC Repowering project?

2) I know you will, but at such time those cost estimations have been completed and forwarded to KPCo, would you please forward same to me as well?...

thank you

Scott C. Weaver
AEP Audinet: 200-1373
Outside: (614) 716-1373

From: Scott C Weaver on 08/03/2011 07:29 PM

To: Lonni L Dieck/OR2/AEPIN@AEPIN

cc:

Subject: Fw: BS1 Repowering Data

Lonni,

We just got "updated" cost estimates in from Chris Beam for the BS1 repowering project. Data looks complete so we'll be running with these cost & performance parameter estimates in updating our KPCo-BS 'UD' analysis in Strategist. As you can see this latest estimate is either **$828M** ($1,111/kW based on a 745-MW 'Mitsubishi' design repowered unit); or **$769M** (*but*, a higher, $1,277/kW based on only a 602-MW ouput based on a "GE" design unit)...

As PART of that process however, I'm also trying to "manage expectations" here... and I think I'll start w/ you. Up till now the expectation is that the BS1 Repowering option was reasonably rooted as the "least-cost" option even though it was based on very, very preliminary "desk-top" estimates done by Engineering (further below). However, as you know, it was determined that we'd go with this lower-capex Repowering option for KPCo due, in large part, to our system capital constraints in that '13-'15 period... You can see that the earlier BS1 repowering projection was $413M in 2011$ (plus about $60 for cost escalation and add'l gas tranportation)... for a total 'as-spent' figure of only **$472M** (or, $738/kW) <u>A figure that we buried in our current L/T capital forecast</u>. In other words, would appear this latest projection is in the range of 50%-70% HIGHER than the earlier estimate, on a $/kW basis.

Point being, we obviously have to run the numbers in Strategist, but based on these new cost estimates and the revised life-cycle economics, this KPCo CC Repowering **may now wind up being very, very close (or perhaps now slightly more costly (??))** than the Dry ("NID" @ 4.5#) FGD option. If that turns out to be the case, how do you think we'd need to proceed?

I would like to recommend that perhaps McCullough be "primed" to this possibility... I have no clue if he's even seen these latest cost estimates from Chris, let alone has any appreciation of the relative increase it represents vs. the $472M figure we've got in that L/T capex fcst now. May not be a bad idea if you were to contact him to discuss/confirm this.

Estimates just received from Chris Beam:

BS Repower Cost Estimates - Preliminary

Cost in MM USD	Opt 1 - 2x2 MHI 501GAC		Opt 2 - 2x2 GE 7FA.05	
	___ MW Net Output		___ MW Net Output	
NGCC Subtotal	655.3		603.2	
AEP Owners Costs	56.7		53.7	
Total NGCC (2011 $)	712.0	#DIV/0!	656.9	#DIV/0!
Interconnections				
Natural Gas Supply	47.4		47.4	
Transmission/SWYD	6.5		6.5	
Total Interconn (2011 $)	53.9		53.9	
Project Total (2011 $)	765.9	#DIV/0!	710.8	#DIV/0!
Escalation	62.2		58.0	
Project Total (As Spent)	828.1	#DIV/0!	768.8	#DIV/0!

Notes: 1. Costs above exclude AFUDC and AEP Allocations.

From: Greg G Pauley on 8/22/2011 12:06 PM

To: Robert P Powers/BC1/AEPIN@AEPIN
cc: Charles R Patton/AEPIN@AEPIN, Ranie K Wohnhas/OR3/AEPIN@AEPIN, Mark C McCullough/AEPIN@AEPIN, William L Sigmon/OR3/AEPIN@AEPIN, Toby Thomas/AEPIN@AEPIN, Lonni L Dieck/OR2/AEPIN@AEPIN, Scott C Weaver/OR4/AEPIN@AEPIN, Karl R Bletzacker/AEPIN@AEPIN, Timothy K Light/AEPIN@AEPIN
Subject: Big Sandy - Alternatives ----- CONFIDENTIAL

Bob: A meeting was held on Aug. 17 to review and discuss the alternatives for Big Sandy since the re-powering information had been received from S&L. Scott Weaver presented information using the attached file as he reviewed and discussed the options of Retrofitting Unit 2, Re-powering Unit 1, Construction of a Gas CC facility and Market options.

PRELIMINARY_Relative BS2 Unit Disposition Alt Economics_081711.xls

With contingency adjustments included; the retrofit option is $839M or $1049/kW
the gas cc option is $1,141M or $1,497/kW
the re-power unit 1 is $1,063M or $1,427/kW

These figures included Carbon and a 15-year depreciation schedule.

Scott's analysis and review was very comprehensive and we included Tim Light and Karl Bletzacker to address the CAPP cost and Gas cost . Additional information in Scotts' packet shows where we were in March of this year and where we are now regarding our cost estimates. During that period Coal came back into play.

It was the consensus of the group that Retrofit was the appropriate action to pursue. Retrofit also allows for the expenses to flow through the Environmental Cost Recovery (ECR) surcharge available to Kentucky Power at the Kentucky PSC. The other alternatives would involve greater scrutiny on the part of the PSC and intervenors since it would not be eligible for the ECR process (ECR is Coal Only). Plus, it would be difficult to pursue gas in this coal state when coal shows to be the least cost.

Other issues discussed during the meeting were:

1. The cost of CAPP coal - I believe Tim Light and Karl Bletzacker are to review their information to make sure the analysis addresses where that cost would be in the future. I will forward their comments to you when I receive them. Karl was comfortable with the numbers, but Tim expressed some concern that I hope he will provide for us to review.
2. Karl Bletzacker felt comfortable (as one can be) the cost figures for gas were accurate.
3. The long tern financial plan had indicated a cost of $472M for Big Sandy and these new figures are higher ($699M or $839w/adj for retrofit)
4. Substantial risk associated with going to the market

The last item we discussed was cost impact to the KY consumer. Attached is a report by Ranie that addresses this issue including the impact Rockport (line 13) would have on KY ratepayers.

Big Sandy Rate Impact of Various Options.xls

There has been some discussion subsequent to the meeting regarding other generation in Ohio being dedicated to Kentucky. I'll defer to Lonni regarding that issue since it is preliminary at this point.

We are available to you for a presentation if you would like. I have alerted Mark and Bill along with Scott and Charles and we will be available to you.

Thanks Greg

Gregory G. Pauley
President & COO
AEP - Kentucky Power Co.
101A Enterprise Drive
Frankfort, Kentucky 40601

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From: Robert L Walton on 9/22/2011 06:32 AM

To: Scott C Weaver/OR4/AEPIN@AEPIN
cc: Stephen J Hiebel/OR4/AEPIN@AEPIN
Subject: Fw: BS2 2016 Scrubber Tie-in Outage Duration?

FYI. Hopefully Steve can advise us the slot he will select in the Spring, 2016 for your use in your modelling for the rate case.

----- Forwarded by Robert L Walton/OR4/AEPIN on 09/22/2011 06:26 AM -----

Robert L Walton/OR4/AEPIN

09/21/2011 03:56 PM

To: Stephen J Hiebel/OR4/AEPIN
cc:
Subject: Re: BS2 2016 Scrubber Tie-in Outage Duration?

We are forecasting the scrubber tie-in for the Spring, 2016, hopefully as late in the Spring as you can get it.

Stephen J Hiebel/OR4/AEPIN

09/21/2011 03:30 PM

To Robert L Walton/OR4/AEPIN@AEPIN

cc

Subject Re: BS2 2016 Scrubber Tie-in Outage Duration?

My last bit of information was 11 weeks in the fall of 2015.

Steve Hiebel
Asset Planning and Fleet Optimization
614-583-7865
Audinet 220-7865
SJHiebel@aep.com

Robert L Walton/OR4/AEPIN

09/21/2011 01:55 PM

To Stephen J Hiebel/OR4/AEPIN@AEPIN

cc

Subject BS2 2016 Scrubber Tie-in Outage Duration?

How long are you showing?

THIS DOCUMENT HAS BEEN REDACTED IN ITS ENTIRETY.

THIS DOCUMENT HAS BEEN REDACTED IN ITS ENTIRETY.

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that address the selection of supply side resource options in the analyses presented by Mr. Weaver in his Direct Testimony. This includes, but is not limited to, any alternative resources that were considered but not cited by Mr. Weaver in his Direct Testimony and/or not used in the analyses.

RESPONSE

No such formal documents exist that specifically isolate or choose the "selection" of the unit disposition options analyzed. Rather, these options that were analyzed have been viewed by AEP and KPCo management as being the most typical, rational and logical set of options available when considering such a coal unit disposition decision.

However, in January of 2012, subsequent to the filing of this case, KPCo management requested the performance on an additional analysis. Please see the response to Sierra Club Item No. 52 part a., First Set, for a description of that additional analysis.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that address the results of the supply side resource options developed by the Company and all iterations of the analyses.

RESPONSE

Please see the response to KIUC 1-28 and KPSC 1-48.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please provide a copy of all analyses that considers natural gas price alternatives at levels less than the lower band alternative scenario prices shown on Exhibit SCW-2 page 2 of 2. If the Company has not performed a sensitivity at prices less than the lower band alternative scenario, then please explain why it has not.

RESPONSE

No such analyses have been performed. The long-term forecast represents a fundamental view of the primary drivers to the energy market. Each primary driver (supply, demand, fuel, policy, etc) is developed by company experts and reflects public and non-public information. These industry views represent a sustainable outlook over the forecast period. The "base" forecast represents a sustainable view of key inputs. Upper and Lower Band forecasts measure the sensitivity of the "base" forecast to sustainable changes in fuel prices (coal and natural gas), emission prices (excluding carbon dioxide), and electricity demand.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please provide an economic analysis for a combined cycle alternative that relies on natural gas price starting at $3.00 per mmBtu in 2012 escalated at the same % rate as the lower band alternative scenario prices shown on Exhibit SCW-2 page 2 of 2.

RESPONSE

The requested analysis has not been performed.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please describe the steps that would be necessary to shutdown and temporarily mothball Big Sandy 2 beyond the 2015 Consent Decree date to delay the installation and cost of the DFGD and instead rely on purchases from PJM.

RESPONSE

Please see Attachment 1 which describes the general steps that would be necessary for a long-term lay-up of Big Sandy 2.

WITNESS: Robert L Walton

AMERICAN® ELECTRIC POWER

ENGINEERING REPORT COVER SHEET

Title: American Electric Power Guiding Principles for the Long Term Layup of Glide Path Units.

PROJECT:	**American Electric Power Guiding Principles for the Long Term Layup of Glide Path Units.**
Document ID:	AEP-FGDSCE-062510
REVISION:	0
DATE:	August 30, 2010

INTERNAL APPROVAL SIGNATURES

	Original Issue	Rev. 1	Rev. 2
AUTHOR: D. E. Hubbard			
REVIEW: M. P. Beck	Michael Beck 9/10/2010		
APPROVAL: T. V. Riordan	T. V. Riordan 9/14/10		

REVISION HISTORY

REV.	SCOPE OF REVISION	APPROVAL
0	Initial Release	DEA TMC

American Electric Power Guiding Principles for the Long Term Layup of Glide Path Units.

For components in a power plant, corrosion can not take place if surfaces are kept free of moisture. The following curve shows the relationship between relative humidity and corrosion rate. For all practical purposes, a surface is considered dry when the relative humidity around the surface is at or below approximately 40%.

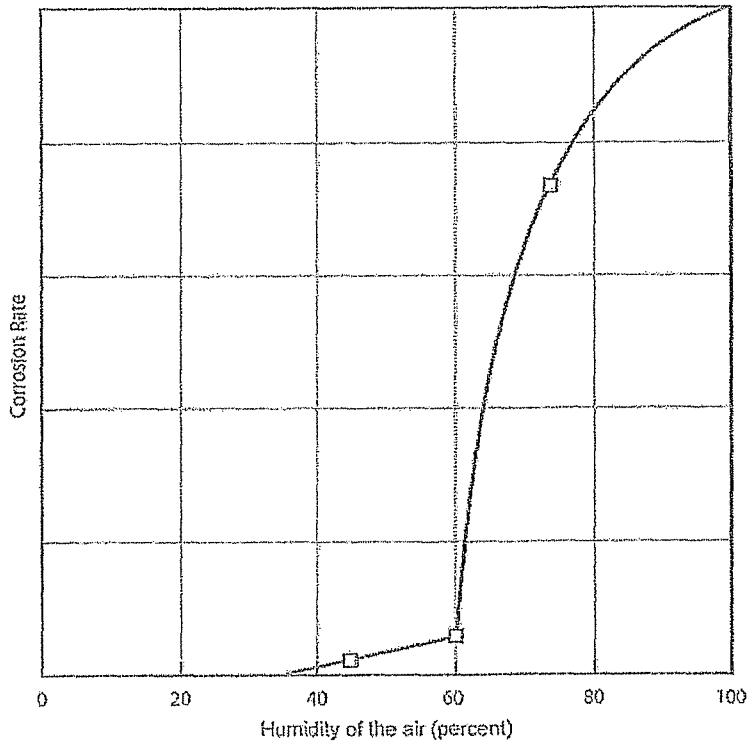

Figure 1: Corrosion Rate of Steel Relative to Humidity of Air

In certain cases the ability to dry a surface is not practical and the surfaces need to be protected using a wet layup procedure. In this case the water needs to be protected from becoming oxygenated. This is accomplished by using a nitrogen blanket. It is also important that the water used to fill a component is oxygen free. Unfortunately at AEP if this water is coming from our condensate storage tanks, the water will be saturated with dissolved oxygen. Our condensate storage tanks are vented to atmosphere. The only means we have at present to remove dissolved oxygen is to spray this water into the condenser steam side above the tube bundle to allow for removal of the oxygen. To accomplish this steam seals have to be on the turbine to allow for vacuum to be pulled on the condenser.

It also should be noted that corrosion (pitting) still can occur in a system that is full of deoxygenated water with a nitrogen blanket. Contaminants like chlorides and sulfates that have deposited over time can cause the initiation of a pit in an aqueous solution. Contaminants like chlorides and sulfates enter the cycle during condenser leaks.
If drying the surfaces or nitrogen is not available and wet layup is being used, the oxygenated water needs to be kept moving such that the water never becomes stagnant.

The general guiding principles to be followed with water and steam touched surfaces are:

1. Completely remove and keep all water and moisture out of components and surfaces to be maintained with a dry layup procedure.
2. If water can not be completely removed and the surface dried, keep water from becoming oxygenated by the surrounding environment during a wet layup. Apply nitrogen blanket.
3. If not possible to keep water from becoming oxygenated during shutdown, then water must not be stagnant. Water must be kept moving.

The level of protection is not the same for the three guiding principles listed. The best protection is always to ensure ID tube surface remains dry. No water present; no corrosion.

Two scenarios for layup will be reviewed. The first scenario is long term layup (3 or more months) where the unit while in layup could be called at anytime to enter the market. The second scenario is long term layup (3 or more months) where the unit will be left out of service for the total period required. The use of vapor phase corrosion inhibitors is also included if mothballing of a unit is to be considered.

NOTE: The intent of this document is to provide guidance for protection of the unit during shutdown conditions. It is intended that this document be used as a guide to develop individual unit specific shutdown protection of the asset.

Scenario 1: Long Term Layup (3 months or more) – Unit available to start up as market dictates.

Boiler

1. Remove all coal from bunkers. Any coal remaining in bunkers, coal valves, pipes, feeders, conveyors, etc. should be removed manually and all access doors, gates, valves, etc., left "open."
2. Unit needs to be deslaged.
3. **Dry Layup (Preferred Method)**
   a.) Flash dry boilers by draining while temperatures are greater than 260F at the steam drum. It is important that pendant superheaters are completely dry. At present different flash drying procedures are being evaluated for success with this method. It is recommended that discussions between the plant and the Steam Generator Equipment Engineering section in Columbus be held to establish a site specific procedure to implement flash drying.
   b.) Reheater needs to be dried following standard reheat drying procedure.
   c.) Relative humidity as measured at steam drum, superheat, and reheat vents need to be maintained at 40% or less. This can be accomplished by leasing or purchasing dehumidification equipment; blowing instrument air thru the boiler superheat, and reheat; or filling circuits with nitrogen.
4. **Wet Layup**
   a.) Boiler needs to remain full of water at a pH of between 9.5 to 10.0.
   b.) Superheat needs to be drained and dried.
   c.) Reheater needs to be dried following standard reheat drying procedure.
   d.) Nitrogen blanket needs to be applied to boiler, superheater, and reheater.
   e.) If wet layup selected, provisions need to be made to protect unit from freezing during cold months.

Turbine

1. The turbine generator major systems should remain intact for the most part, but be left in a shutdown mode, such as at the start of a GBIR outage, for segmented periods of time during the layup. Oil lubricated systems from forced pressure sources should be operated occasionally to provide a corrosion protective film on the surface (lube oil, hydrogen seal oil, control/EHC fluid). The exception would be a unit with a water- cooled stator. This system should be drained and dried and then purged with a dry air source (from a dehumidification unit or other device) to minimize any crevice corrosion within the system.
2. The turbine steam path, including inlet/outlet piping and valve casings would benefit from a warm, dry air purge and supply during the layup period. Certain steps to provide a continuous path of air circulation thru the turbine components can and has been engineered in the past and should not pose any large problems. If a source of warm, dry air is not to be installed, air drying and then steps to minimize the formation of condensation on the components would be the next best choice.
3. The generator and exciter assemblies represent components that would not tolerate moisture for prolonged periods and include components (e.g. retaining rings) that could readily fail at rated speeds due to effects of corrosion. It is

recommended to keep the generator and exciter rotors in place and protect the windings inside the stators with a dry gas, preferably air or nitrogen, or even carbon dioxide. Using a dry air purge with leakage out the rotor end seals would be successful. Using N2 or CO2 will require some means of monitoring for leakage, especially at the shaft ends, and would result in some hazardous risk due to leaks. Supply equipment would be necessary in each case, and could be as simple as gas supply bottles and regulators or a branch connection from the dehumidified air supply. Keeping the H2 in the unit with the seal system in service is another option that can be considered.

4. The operating guidelines prior to removing the unit from service before a layup period should be followed to minimize the degree of deposits that will remain on the turbine blades. A "water wash" will benefit the inlet stages of the HP/IP turbines and the later stages of the LP turbines the most and thus reduce the area of corrosion potential during layup. Also, a periodic plan to operate equipment (oil and water pumps, turning gear, vapor extractors, etc.) should also be established.

Condensate/Feedwater

The condensate and feedwater systems including the economizer needs to be drained and dried. The condenser hotwell needs to be also drained and dried along with the shell side of the low pressure and high pressure heaters and deaerator storage tank. Dried is defined as a relative humidity maintained below 40%.

Condenser

If the circulating water system is not needed to stay in service for cooling of auxiliary systems then it is recommended that the circulated water side of the condenser be drained opened and dried by blowing warm air thru waterbox and tubes. If circulating water valves leak thru, then the circulating water needs to be kept moving by operation of the circulating water pump. This is necessary to avoid stagnant water conditions that can lead to corrosion. If the circulating water pumps need to remain in service because of leaking valves then this may cause issues with being able to keep the steam side of the condenser dry. If the steam side of the condenser can not be kept dry while operating the circulating water system then it is recommended that the circulating water system be shut down and we will sacrifice pitting and corrosion of the circulating water side to ensure we can keep the steam side of the condenser dry.

Auxiliary systems

Any coolers on the low pressure service water, auxiliary cooling, or closed cycle cooling systems need to be either isolated and drained or they need to have flow on them all the time. Stagnant water in coolers has to be avoided.

Water Treatment Plant

In most cases the water plant will still be in operation providing water to operating units. For units that the water plant supplies filtered water only, and filtered water is not needed the following is recommended:

A. Coagulator needs to be drained and hosed out.

B. Clearwell to be left full, treated with bleach and used to backwash the downstream filters and softeners weekly to keep from having biological activity start to grow inside this equipment. Backwashing only needs to be long enough to displace water inside vessels.
C. If clearwell level goes low, it should be refilled but not thru coagulator. If refilled, bleach needs to be added to clearwell.

Condensate Storage Tanks

It is not recommended that condensate storage tanks be drained during long term shutdown. Tank temperatures need to be monitored such that if temperatures approach 35 F, arrangements are made to periodically circulate storage tank water. This can be simply accomplished by moving water from out of service tanks to in service tanks.

Chemical Feed Systems

For boiler caustic feed systems it is recommended that all piping be flushed and drained. The boiler caustic feed tank can either be drained and flushed or left full as long as mixer stays in service and tank is protected from freezing.On the condensate ammonia and oxygen scavenger feed system it is recommended to drain piping but leave chemicals in tanks and ensure tanks do not freeze.

Scenario 2: Long Term Layup (3 months or more) – Unit Remains Out of Service for Total Period.

Boiler

1. Remove all coal from bunkers. Any coal remaining in bunkers, coal valves, pipes, feeders, conveyors, etc. should be removed manually and all access doors, gates, valves, etc., left "open."
2. Remove ash and slag deposits from ash hoppers, and accumulations from breeching and dampers. Remove all ash from dead air spaces and inside convection pass areas. Ash accumulations allowed to stay in these areas will significantly increase externally corrosion.
3. Unit needs to be deslaged and external tube surface needs to be kept dry by blowing warm air thru unit or surface needs to be neutralized by spraying with a sodium carbonate solution to neutralize any acidic species on the OD of the tube to prevent external corrosion.
4. **Dry Layup (Preferred Method)**
   a.) Flash dry boilers by draining while temperatures are greater than 260° F at the steam drum. It is important that pendant superheaters are completely dry. At present different flash drying procedures are being evaluated for success with this method. It is recommended that discussions between the plant and the Steam Generator Equipment Engineering section in Columbus be held to establish a site specific procedure to implement flash drying.
   b.) Reheater needs to be dried following standard reheat drying procedure.
   c.) Relative Humidity as measured at steam drum, superheat, and reheat vents need to be maintained at 40% or less. This can be accomplished by leasing or purchasing dehumidification equipment; blowing instrument air thru the boiler, superheat, and reheat; or filling circuits with nitrogen.
5. **Wet Layup**
   a.) Boiler needs to remain full of water at a pH of between 9.5 to 10.0
   b.) Superheat needs to be drained and dried.
   c.) Reheater needs to be dried following standard reheat drying procedure.
   d.) Nitrogen blanket needs to be applied to boiler, superheater, and reheater.
   e.) If wet layup selected, provisions need to be made to project unit from freezing during cold months.

Turbine

1. The turbine generator major systems should remain intact for the most part, but be left in a shutdown mode, such as at the start of a GBIR outage, for segmented periods of time during the layup. Oil lubricated systems from forced pressure sources should be operated occasionally to provide a corrosion protective film on the surface (lube oil, hydrogen seal oil, control/EHC fluid). The exception would be a unit with a water-cooled stator. This system should be drained and dried and then purged with a dry air source (from a HIT Skid or other device) to minimize any crevice corrosion within the system.

2. The turbine steam path, including inlet/outlet piping and valve casings would benefit from a warm, dry air purge and supply during the layup period. Certain steps

to provide a continuous path of air circulation thru the turbine components can and has been engineered in the past and should not pose any large problems. If a source of warm, dry air is not to be installed, air drying and then steps to minimize the formation of condensation on the components would be the next best choice.

3. The generator and exciter assemblies represent components that would not tolerate moisture for prolonged periods and include components (e.g. retaining rings) that could readily fail at rated speeds due to effects of corrosion. It is recommended to keep the generator and exciter rotors in place and protect the windings inside the stators with a dry gas, preferably air or nitrogen, or even carbon dioxide. Using a dry air purge with leakage out the rotor end seals would be successful. Using N2 or CO2 will require some means of monitoring for leakage, especially at the shaft ends, and would result in some hazardous risk due to leaks. Supply equipment would be necessary in each case, and could be as simple as gas supply bottles and regulators or a branch connection from the dehumidified air supply. Keeping the H2 in the unit with the seal system in service is anther option that can be considered.

4. The operating guidelines prior to removing the unit from service before a layup period should be followed to minimize the degree of deposits that will remain on the turbine blades. A "water wash" will benefit the inlet stages of the HP/IP turbines and the later stages of the LP turbines the most and thus reduce the area of corrosion potential during layup. Also, a periodic plan to operate equipment (oil and water pumps, turning gear, vapor extractors, etc.) should also be established.
5. Reheat drying needs to be initiated during shutdown of the unit.

Condensate/Feedwater

The condensate and feedwater systems including the economizer needs to be drained and dried. The condenser hotwell needs to be also drained and dried along with the shell side of the low pressure and high pressure heaters and deaerator storage tank. Dried is being defined as a relative humidity maintained below 40%.

Condenser

If the circulating water system is not needed to stay in service for cooling of auxiliary systems then it is recommended that the circulated water side of the condenser be drained opened and dried by blowing warm air thru waterbox and tubes. If circulating water valves leak thru, then the circulating water needs to be kept moving by operation of the circulating water pump. This is necessary to avoid stagnant water conditions that can lead to corrosion. If the circulating water pumps need to remain in service because of leaking valves then this may cause issues with being able to keep the steam side of the condenser dry. If the steam side of the condenser can not be kept dry while operating the circulating water system then it is recommended that the circulating water system be shut down and we will sacrifice pitting and corrosion of the circulating water side to ensure we can keep the steam side of the condenser dry.

Auxiliary Systems

Any coolers on the low pressure service water, auxiliary cooling, or closed cycle cooling systems need to be either isolated and drained or they need to have flow on them all the time. Stagnant water in coolers has to be avoided.

Water Treatment Plant

In most cases the water plant will still be in operation providing water to operating units. For units that the water plant supplies filtered water only, and filtered water is not needed the following is recommended:

A. Coagulator needs to be drained and hosed out.
B. Clearwell to be left full, treated with bleach and used to backwash the downstream filters and softeners weekly to keep from having biological activity start to grow inside this equipment. Backwashing only needs to be long enough to displace water inside vessels.
C. If clearwell level goes low, it should be refilled but not thru coagulator. If refilled, bleach needs to be added to clearwell.

Condensate Storage Tanks

It is not recommended that condensate storage tanks be drained during long term shutdown. Tank temperatures need to be monitored such that if temperatures approach 35 F, that arrangements are made to periodically circulate storage tank water. This can be simply accomplished by moving water from out of service tanks to in service tanks.

Chemical Feed Systems

For boiler caustic feed systems it is recommended that all piping be flushed and drained. The boiler caustic feed tank can either be drained and flushed or left full as long as mixer stays in service and tank is protected from freezing. On the condensate ammonia and oxygen scavenger feed system it is recommended to drain piping but leave chemicals in tanks and ensure tanks do not freeze.

The remaining sections of this report covers general considerations for protection of electrical equipment, chemical instrumentation, air pollution control equipment and a section on using vapor phase inhibitors for mothballing units.

These sections again offer general guidelines that will need to be considered on a case by case basis as a unit specific layup document is developed.

Electrical Equipment

Reserve Aux and Unit Aux Transformers

1. If transformer has conservator, make certain that oil level in conservator is at normal 25° C level. Also make certain that isolation valve from conservator to tank is open. Check oil level every three (3) months.
2. If conservator has a dehydrating breather make certain that desiccant is dry. Check desiccant every three (3) months.
3. If conservator is nitrogen blanketed make certain that nitrogen bottle is full and that the regulating valve is open and functioning correctly. Check nitrogen bottle every three (3) months.
4. If transformer is sealed tank design, make certain that nitrogen bottles are full and that the regulating valve is open and functioning properly. Make certain oil level is normal and check every three (3) months. Check nitrogen bottle every three (3) months
5. Collect an oil sample and have analysis done. Repeat every 6 months.
6. Inspect transformer for oil leaks and repair leaks before laying up.
7. Make certain that control panels have anti-condensation space heaters installed, are functional, and are energized.
8. Make certain that tank grounds are properly installed.
9. If transformer has pumps and fans it is recommeded running both for a few minutes during three (3) month inspection.
10. If lightning arrestors are installed make certain they are functional.
11. If abnormal oil analysis is observed consider having oil process done before returning to service.
12. Perform Doble test and TTR test before returning to service.

GSU Transformers

1. All of the above.
2. If GSU will not be required to be back fed for plant power source, disconnect leads from HV-bushings. Ground bushings.

Bus Systems

1. Non-seg phase bus
    a. If bus has anti-condensation heaters make certain that they are functioning properly and are energized.
    b. Bus should be relatively clean before laying up.
    c. If bus has drain vents make certain that they are unobstructed and functioning properly.
    d. Make certain that all inspection covers, access covers, etc. are installed. If any covers are missing the openings shall be sealed, for example, by placing tarpaulin over the opening and fixing cover material in place with

clamps, screws into existing holes (i.e. holes for original cover. New holes shall not be drilled.) etc.

e. Any vermin guards shall be checked and repaired if necessary before laying up.
f. Take a Polarization Index of the bus insulation with a DC megger and record the results. Repeat every three (3) months. Progressively lower values of PI readings indicate an ingress of moisture. Corrective action should be taken to avoid further lowering of insulation resistance.
g. Just prior to return to service the bus shall have a Polarization Index done with DC megger.

2. **Isolated phase bus**
   a. All of the above.
   b. If the bus is forced-cooled, drain the air-to-water heat exchanger. Fill heat exchanger with glycol for freeze protection. Heat exchanger shall be flushed and filled with water prior to return to service.

Switchgear/MCCs

1. Make certain that cubicles and main bus compartment are clean and dry.
2. Rack out all breakers/starter buckets. Coat all primary contacts with a type "B" rust preventative material.
3. Make certain that all external covers/panels are installed.
4. If cubicles/starter compartments have space heaters make certain that they function correctly and are energized.
5. Take a Polarization Index of the main bus insulation with a DC megger and record the results. Repeat every three months. Progressively lower values of PI readings indicate an ingress of moisture. Corrective action should be taken to avoid further lowering of insulation resistance.
6. Breakers must go through complete preventative maintenance procedure (e.g., lubrication, contact wipe checked, etc.) before being placed back in service.
7. Breakers must be high current tested before being placed back in service.
8. Protective relays shall be tested and calibrated before placing switchgear back into service.

Medium Voltage Motors

1. If possible motor should be stored indoors in a clean dry area.
2. If indoor storage is not possible, the motor must be covered with a tarpaulin. This cover should extend to the base, however it should not tightly wrap the motor. This will allow the captive air space to breath, minimizing formation of condensation.
3. Precautions should be taken to prevent rodents, snakes, bird, or other small animals from nesting inside of the motors. In areas where they are prevalent, precautions must be taken to prevent insects, such as mud dauber wasp, from gaining access to the interior of the motor.

4. Coat all exposed machined surfaces, such as shaft extensions, C-faces, etc. with solid film corrosion inhibitor such as Rust-Ban 326 or equivalent.
5. Insure that motor temperatures are maintained at five (5) degrees F minimal above ambient temperature. If motor is equipped with space heaters make certain that they are energized.
6. Make certain that the shaft lock bar is applied to shaft to prevent movement.
7. Motors with greased bearings must have lubricated cavities completely filled with lubricant during storage. Remove drain plug and fill cavity with grease until grease begins to purge from drain opening. Review motor's lubrication nameplate for correct lubricant.
8. Motors with oil lubricated bearings must have the oil reservoir drained and filled to maximum level with a properly selected oil containing rust and corrosion inhibitors such as Texaco Regal Marine #77, Mobil Vaprotec Light, or an equivalent. Oil should be inspected monthly for evidence of moisture or oxidation.
9. All motors must have shaft rotated 10 ¼ revolutions monthly. Remove the shaft lock bar to rotate and then re-install shaft lock bar.
10. Take Polarization Index readings with DC megger and record the results. Repeat every six (6) months. Progressively lower values of PI readings indicate an ingress of moisture. Corrective action should be taken to avoid further lowering of insulation resistance.
11. Before placing motor back into service make certain of the following:
    a. Motors with oil bearings have correct lubricating oil installed in reservoir.
    b. Motors with grease bearings should be filled with new grease per motor manufacturer's instructions.
    c. Make certain that PI value is 2 or greater.

Chemical Instrumentation

Analyzer Make	Parameter	Shut Down Procedure <3 weeks	Shut Down Procedure >3weeks	Start Up Procedure
Yokogawa	pH	Leave probes within the sample only with the sample. Starting up the analyzer might require a 3 hour flush down period before probes are responding correctly. It is imperative to keep the sensors wet at all times. The most problematic is the reference electrode with its KCL solution. There is a possibility for the KCL to salt out and have solids develop in the electrodes and in the tubing over time.	Remove the electrodes and store them in a pH storage solution (saturated KCL should be good). Power down instrument if easily accessible to protect electronics from surges.	Re-install the probes and check the status of the reference electrode electrolyte. Refill if necessary with the correct solution. Run probes for 3 hours in sample (after lines have been blown down to prevent fowling of the probes). If no alarms are present, particularly the 5.2 alarm, perform a normal buffer calibration.
Honeywell	pH	If possible valve in demineralized water to probes, Leave probes within the sample only with sample. Starting up the analyzer might require a 3 hour flush down period before probes are responding correctly.	Remove the electrodes and store them in a pH storage solution (saturated KCL should be good). Power down instrument if easily accessible to protect electronics from surges.	Re-install the probes and check the status of the reference electrode electrolyte. Refill if necessary with the correct solution. Run probes for 3 hours in sample (after lines have been blown down to prevent fowling of the probes) and then perform a normal buffer calibration (2 point)
Yokogawa	Conductivity	NOTHING	NOTHING	Flow cells might require a cleaning with a brush as well as the probe.
Honeywell	Conductivity	NOTHING	NOTHING	Flow cells might require a cleaning with a brush as well as the probe.
Waltron	Silica	Remove all reagents and dispose. Place all of the straws into bottle with DI water. Perform 5 consecutive primes to flush lines of any reagent. Remove DI bottle and perform 5 more primes to flush any sample left over. Power down the instrument.	Remove all reagents and dispose. Place all of the straws into bottle with DI water. Perform 5 consecutive primes to flush lines of any reagent. Remove DI bottle and perform 5 more primes to flush any sample left over. Power down the instrument.	Replace the pump tubing, re-install reagents and DI water, and perform 3 consecutive prime cycles followed by a calibration.
Hach	Silica	If possible, run DI water through analyzer through analyzer and keep in operation. If not, perform a weekly prime and calibration then power down the instrument. Inspect the status of the reagents to ensure no precipitation has formed.	Dispose of all reagents but keep the bottles. Rinse the bottles well with DI water. Fill bottles up with DI water. Re-install into the analyzer. Run 5 primes. Remove and dispose DI water. Re-install empty bottles to blow tubing out. Run 5 more primes. Empty sample cell, remove pinch valve tubing from valve, close off sample flow and air pressure, and power down the analyzer.	Re-establish sample and air flow to instrument, reinstall the pinch valve tube and perform 2 primes followed by a calibration. If calibration value isn't within (50ppb/500), then let analyzer run on sample for 2 hours and perform another calibration. Sample cell could require a cleaning if valves aren't within limits.

Analyzer Make	Parameter	Shut Down Procedure <3 weeks	Shut Down Procedure >3weeks	Start Up Procedure
Orion	Sodium	Power down instrument and turn off sample flow.	Remove electrodes and store in the electrode protective caps with DI water and a small amount of reference electrolyte (CsBr, CsCl, or NH4Cl), remove buffer and diffusion tubing shut sample valve and power down the instrument. **Reference Electrode:** Remove the reference electrode and fill completely with reference electrode electrolyte. Once filled, remove the side-arm tube from the reference electrolyte and cap both the bottle of the electrolyte and the side-arm of the reference electrode. If you do not have the original cap for the side-arm than you can alternatively use parafilm. Second, cap the sensing end of the reference electrode with the protective cap originally supplied or parafilm. Store in original electrode box/packaging or in a safe location. Depending on the age of the reference electrode and the amount of time the electrode is stored, it is possible to experience a shift. The electrode will need to be tested upon start up to see if the prolonged storage has had a significantly negative effect upon the E0. Be sure to remove the internal electrolyte upon start up and replace with fresh electrolyte. Also, be sure to hydrate the electrode prior to calibration for a couple of hours for optimal response. **Reagent:** Follow the procedure in the Sodium Analyzer User Guide for removal of the reagent. Be sure to turn off the airpump, prior to removal of the reagent to avoid splattering of the reagent. Cap the reagent and either store in a fume hood, or discard the reagent. Most reagent once exposed to the environment will have a limited life-span, so it may be best to discard if the shutdown is more than a few months. Discard the used diffusion tubing once you have removed the reagent. Install a new diffusion tube upon start-up and recalibration. **Fluidics:** Once the reagent is removed, then the fluidics are ready to be taken off-line. You do not need to run water to the analyzer during this period. The analyzer can remain dry. Upon start-up you will want to clean or change the bypass filter (60 micron stainless steel) to ensure proper flow. Also, continue to wash down the analyzer with fresh sample for a few hours prior to calibration. Depending on the age of the restrictor tube (located off the flowmeter/rotometer) you may want to check or replace to ensure there isn't any particles trapped causing low flow issues upon start-up.	Re-install electrodes, new buffer and diffusion tubing and let probes rinse down after establishing sample flow to the instrument for at least 3 hours. Perform a calibration.

Analyzer Make	Parameter	Shut Down Procedure <3 weeks	Shut Down Procedure >3weeks	Start Up Procedure
Waltron	Sodium	Power down instrument and turn off sample flow.	Remove electrodes and store in the electrode protective caps with DI water and a small amount of reference electrolyte (NH4Cl or KCl), remove buffer, shut sample valve and power down the instrument.	Re-install electrodes, new buffer and let probes rinse down after establishing sample flow to the instrument for at least 3 hours. Perform a calibration.
SWAN	Sodium	Power down instrument and turn off sample flow.	Remove electrodes and store in the electrode protective caps with DI water and a small amount of reference electrolyte (NH4Cl or KCl), remove buffer, shut sample valve and power down the instrument.	Re-install electrodes, loosen reference electrode sleeve junction, install buffer and let probes rinse down after establishing sample flow to the instrument for at least 1 hour. Perform a calibration.
Waltron/ABB	DO	Remove probe, place in protective cap with DI water soaked on a sponge, store in refrigerator or cool place.	Remove probe, place in protective cap with DI water soaked in sponge, store in refrigerator or cool place.	Re-install probe and let probe's temperature to stabilize for at 30 minutes, perform calibration.
Hach	DO	Leave probe in flow cell, turn off sample flow and LEAVE POWER ON.	Remove probe and perform membrane removal and flush KOH procedure, store in cool/dry place.	Replace membrane and electrolyte and if oxide-precipitation perform a probe cleaning, let probe stabilize in sample for 3 hours, then perform a calibration.
Analyzer Make	**Parameter**	**Shut Down Procedure <3 weeks**	**Shut Down Procedure >3weeks**	**Start Up Procedure**
Orion	Chloride	Remove electrodes and store in the electrode protective caps with DI water and a small amount of reference electrolyte (CsBr, CsCl, or NH4Cl), remove buffer and diffusion tubing shut sample valve and power down the instrument.	Remove electrodes and store in the electrode protective caps with DI water and a small amount of reference electrolyte (CsBr, CsCl, or NH4Cl), remove buffer and diffusion tubing shut sample valve and power down the instrument. **Reference Electrode:** Remove the reference electrode and fill completely with reference electrode electrolyte. Once filled, remove the side-arm tube from the reference electrolyte and cap both the bottle of the electrolyte and the side-arm of the reference electrode. If you do not have the original cap for the side-arm than you can alternatively use parafilm. Second, cap the sensing end of the reference electrode with the protective cap originally supplied or parafilm. Store in original electrode box/packaging or in a safe location. Depending on the age of the reference electrode and the amount of time the electrode is stored, it is possible to experience a shift. The electrode will need to be tested upon start up to see if the prolonged storage has had a significantly negative effect upon the E0. Be sure to remove the internal electrolyte upon start up and replace with fresh electrolyte. Also, be sure to hydrate the electrode prior to calibration for a couple of hours for optimal response. **Reagent:** Follow the procedure in the Sodium Analyzer User Guide for removal of the reagent. Be sure to turn off the airpump, prior to removal of the reagent to avoid splattering of the reagent. Cap the reagent and either store in a fume hood, or discard the reagent. Most reagent once exposed to the environment will have a limited life-span, so it may be best to discard if the shutdown is more than a few months. Discard the used diffusion tubing once you have removed the reagent. Install a new diffusion tube upon start-up and recalibration.	Re-install electrodes, new buffer and let probes rinse down after establishing sample flow to the instrument for at least 3 hours. Perform a calibration.

			Fluidics: Once the reagent is removed, then the fluidics are ready to be taken off-line. You do not need to run water to the analyzer during this period. The analyzer can remain dry. Upon start-up you will want to clean or change the bypass filter (60 micron stainless steel) to ensure proper flow. Also, continue to wash down the analyzer with fresh sample for a few hours prior to calibration. Depending on the age of the restrictor tube (located off the flowmeter/rotometer) you may want to check or replace to ensure there isn't any particles trapped causing low flow issues upon start-up.	

Air Pollution Control Equipment

Urea System

A. Layup is being defined as complete removal of the concentrated urea from the storage tanks and recirc system piping. This includes a final rinse, piping air purge, and removal of the waste diluted urea leaving the storage tanks and piping clean and empty.

B. The tank heaters will be off and the piping heat trace can be de-energized if it is felt the piping was purged sufficiently that freezing will not damage the piping.

C. Leave the heat tracing on the Urea Dilution Water Skid energized to protect its piping.

Air Pollution Control Equipment

1. ESP
    a. Empty all hoppers
    b. Vacuum out excess ash in ESP & inlet and outlet nozzles
    c. Wash Clean the ESP for long term storage.
    d. Wash with a caustic injection into the water or a sodium bicarbonate rinse. Test the drain water for pH and not stop washing until it is neutral range (6.5 – 7.5)
    e. Repair known casing leaks especially on horizontal surfaces
    f. Run purge air system and hopper heater 48 hour after water cleaning to dry equipment
    g. On stacks with multiple units entering them, seal off the duct ahead of the stack breaching damper to minimizes air in-leakage and the formation of aerosols in the stack

2. Fabric Filters
    a. Empty all hoppers
    b. Vacuum out excess ash in FF & inlet and outlet nozzles
    c. Repair known casing leaks especially on horizontal surfaces

3. TR Set
    a. Conventionals (nothing required)
    b. High Frequency - Ensure the control cabinet heaters are in-service to minimize condensation inside the control

4. Rappers (nothing required)

5. Purge Air System (nothing required)

6. FARS
   a. **Wet**
      i. Drain wet transport to prevent freezing
      ii. Isolate water supply to hydroveyor for freeze protection
   b. **Dry**
      i. Empty all separators
      ii. Isolate water supply to vacuum pumps for freeze protection

7. Flue Gas Conditioning Systems
   a. Purge lines per OEM procedures & SCR ammonia system winterizing procedures
   b. Neutralize any line carrying highly corrosive gases
   c. Top off all liquid sulfur tanks and turn off heating and allow them to freeze. Heat should be returned to the tank 72 hours prior to start up.
   d. Any system using Anhydrous Ammonia should have the tanks drained to minimize the potential for ammonia leak to atmosphere.

Note: The equipment should be inspected and any identified or previously known mechanical or electrical issues should be repaired at this time.

Vapor Phase Inhibitors
Mothballing of Units

Description of Surfaces Being Protected	General Description and Class of the Vapor Corrosion Inhibitor	Cortec Product Trade Name and Number
Protection of Interior Steel Surfaces, such as, boiler tubes, condenser (tubes, tubesheet and waterbox), heat exchangers, turbines, generators, pumps, tanks and piping. A key aspect of this VaporCorrosion Inhibitor (VpCI) is that it must be contained in relatively air tight or at least covered from weather intrusion.	Waterbased corrosion inhibitor for the protection of enclosed steel surfaces. System and/or surfaces must be empty. Protection is generally limited to 12 months.	V p C I 3 3 7
Protection of Exterior Steel Surfaces (i.e. exposed to weathering). These VCI materials are intended for surfaces that are bare (without a protective coating). Surfaces may include bare piping, electrostatic precipitator plates, structural steel, and other misc. equipment.	Solvent (mineral spirits) based forming a wax-like film containing the vapor corrosion inhibitor. Applied by brush or by spraying to achieve a minimum continuous film of 2-3 mils. Requires abrasive blast surface preparation. Removal requires mineral spirits dilution or strong hot detergent cleaning.	**VpCI 368/369 VpCI 368 is a harder waxier film and provides longer term protection but is more difficult to remove. VpCI 369 is more like and thickened oil and is easier to remove**
Electrical Equipment Emitter. For use on the interior of electrical boxes, cabinets, switch gear equipment and other enclosed electrical equipment. May also be used for enclosed electric motors and electrical instruments.	This is a self-contained VpCI emitter that attaches to the inside of any electrical enclosure and emits a corrosion inhibitive vapor	**VpCI-111**
Electrical Equipment Corrosion Inhibiting Spray. For use on electical and electronic conductors and connections, in sheltered applications and/or for enclosed electrical equipment. May also be safely used on low voltage circuits and relays without changing its conductivity. May be safely applied on plastics, elastomers and other non-metalic circuit boards.	This spray applied material (via hand held spray can) is intended for direct use on sheltered electric/electronic switches, circuit boards, electical contacts and other electical applications where it prevents the formation of metal oxides on the electrical surfaces. May be used on aluminum, copper, steel and other non-ferrous metal surfaces.	**ElectriCorr VpCI -238 and VpCI 239 (Available in 9.45 oz spray cans)**
Vapor Phase Corrosion Inhibiting Films and Bags for packaging fasteners, metal parts, and other equipment that can be easily packaged	This is a packaging film which contains vapor phase corrosion inhibitors. It is suitable for the protection from oxidation of ferrous and non-ferrous metals. Ideal for small parts, fasteners, pipe fittings, and other item that can be placed in a package. Provides up to 5 years corrosion protection.	**VpCI-126 Blue This Is a transparent film**
Vapor Phase Corrosion Inhibiting Shrink Wrap Films for packaging fasteners, metal parts, and other equipment that can be easily packaged	The high strength shrink composite film contains both VpCI and UV inhibitors. This fire retardant film provides corrosion protection ferrous and non-ferrous metals. May be used to protect large equipment and assemblies. Provides excellent protection for shipping equipment including overseas shipping.	**MilCorr VpCI Shrink Film**

Oil Additives for Lube Oil and Hydralic Oil Tanks and Systems. This viscous liquid is intended to be added to the oil in operating and non-operating lubricating and hydralic oil systems.	This rust inhibitive additive provides excellent protection during operating conditions as well as shut down conditions. It is effective with both mineral and synthetic oil systems. Provides protection for both ferrous and non-ferrous metals. It has low toxicity and is thermally stable.	**M-529 and M-530 Oil Based Corrosion Inhibitor**
Corrosion Inhibiting Grease- This product is a lithium complex grease for both operating and lay-up conditions	This grease is suitable for protecting non-coated surfaces such as flange faces, lubricating sleeves, ball and roller bearings, and other non-coated equipment surfaces that requires lubrication as well as corrosion protection. Suitable for exposure to salt water and brine as well as normal weathering.	**Corrlube Grease**
Closed Loop Water System Corrosion Additive- Also helps to prevent scale build up.	This additive provides long term protection for ferrous and non-ferrous metal water systems from oxidation in fresh water, steam, condensate and glycol closed loop systems. The additive is readily water soluble. The effective concentration level is 0.1-0.2% (1000-2000ppm).	**VpCI-649 Water System Additive**

Kentucky Power Company

REQUEST

Please quantify the costs to shutdown and temporarily mothball Big Sandy 2 beyond the 2015 Consent Decree date while preserving the ability to subsequently restart the unit and comply with the relevant environmental requirements at a later date.

RESPONSE

The costs to shutdown and temporarily mothball Big Sandy 2, as stated in the question, have not been quantified but the Company would not delay the installation of the DFGD and rely upon purchases because any delay may result in market risk and significant increases in cost.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that address the availability and/or economics of purchasing existing natural gas generation either through an ownership structure or through a PPA in lieu of the self-build natural gas options addressed by Mr. Weaver in his Direct Testimony.

RESPONSE

No such documents exist.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents that address the availability and/or economics of purchasing the output or the assets of the generating facility in Zelda, Kentucky owned by the Riverside Generating Company, LLC.

RESPONSE

Please see attachments to the Company's response to AG 1-22.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents evaluating and/or ranking competitive bids for capacity and energy prepared by or on behalf of AEP and/or its operating utilities within the last two years.

RESPONSE

Kentucky Power interpreted this request for purposes of this response to mean "competitive bids for capacity and energy" that were received by the Company and to encompass only written capacity and energy offers exceeding 50 MW and not involve renewable energy. Generally, such written offers are preliminary indicative offers that are made subject to further discussion and review by offeror's management prior to being entertained for acceptance. Based on those parameters, Kentucky Power located one responsive document for the stated time period which document is considered to be highly confidential. Please see the Attachment for which confidential protection is being sought.

WITNESS: Ranie K Wohnhas

THIS DOCUMENT HAS BEEN REDACTED IN ITS ENTIRETY.

Kentucky Power Company

REQUEST

Please provide a copy of all analyses, emails, and all other documents evaluating financing alternatives to the Company's proposal in this proceeding, including, but not limited to, project financing, leasing, and securitization.

RESPONSE

The Company looked at two alternative financing options, a cash return on CWIP and securitization. The Company's securitization financing option assumed that the Company earned an equity return equal to the return it would have earned under the traditional financing method and securitized the remaining investment at a favorable financing rate. Attachment 1 compares the CWIP option, the securitization option and a combined CWIP and securitization option to the traditional recovery methodology.

WITNESS: Ranie K Wohnhas

Big Sandy DFGD
Financing Options

Scenario	NPV total company	1st year in service rev reqmt total co	1st year in service rev reqmt juris	1st year in service % increase*	Comments
Traditional Return on Rate Base	$ 1,539,131,280	$ 206,597,218	$ 177,735,861	31.2%	10.69% WACC, 10.5% ROE, 15 year depreciation, 5% discount rate
CWIP at WACC	$ 1,512,150,440	$ 190,049,101	$ 163,148,995	28.6%	10.69% WACC, 10.5% ROE, 15 year depreciation, 5% discount rate
Securitized Mortgage Financing	$ 1,483,706,536	$ 186,012,016	$ 159,590,377	28.0%	10.5% ROE, 3% LTD, 15 year mortgage and depreciation, 5% discount rate
CWIP Securitized Mortgage Financing	$ 1,462,581,247	$ 171,639,096	$ 146,920,908	25.8%	10.5% ROE, 3% LTD, 15 year mortgage and depreciation, 5% discount rate

* KY jurisdictional revenue = $ 569,593,245

Current

Calculation of Weighted Cost of Capital as of 4/30/2010

	Balance	Cap Structure	Cost of Capital Rates	WACC Net of Tax	GRCF	WACC Pre Tax
Long term Debt	$ 550,000,000	51.941%	6.48%	3.37%		3.37%
Short Term Debt		0.000%	0.83%	0.00%		0.00%
A/R Financing	$ 43,588,933	4.116%	1.22%	0.05%		0.05%
Common Equity	$ 465,314,088	43.943%	10.50%	4.61%	1.5762	7.27%
Total	$ 1,058,903,021	100.000%		8.03%		10.69%

Additional Financing

Calculation of Weighted Cost of Capital as of 4/30/2010

	Balance	Cap Structure	Rates	Net of Tax	GRCF	Pre Tax
Long term Debt	$ -	0.000%	6.48%	0.00%		0.00%
Securitized Debt	$ 535,997,007	56.095%	3.00%	1.68%		1.68%
A/R Financing	$ -	0.000%	1.22%	0.00%		0.00%
FGD Equity	$ 419,515,485	43.905%	10.50%	4.61%	1.5762	7.27%
Common Equity	$ -	0.000%	10.50%	0.00%	1.5762	0.00%
Total	$ 955,512,492	100.000%		6.29%		8.95%

Difference in Revenue Requirement	
Difference in Pre Tax WACC	1.74%
Rate Base in year 1 - no accelerated depreciation	$ 891,811,659
Savings in year 1	15,517,523

Big Sandy financing analysis

	Traditional Return on Rate Base	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
	Cumulative Construction Expenditures	$ 92,368,000	$ 235,638,000	$ 455,916,000	$ 839,325,067										
	AFUDC	$ 5,977,000	$ 20,561,000	$ 51,993,000	$ 100,975,000										
	Preliminary Scrubber Analysis2004-2006	$ 15,212,425	$ 15,212,425	$ 15,212,425	$ 15,212,425										
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ -	$ -	$ -	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492
2	Less: Accumulated Depreciation	$ -	$ -	$ -	$ 63,700,833	$ 127,401,666	$ 191,102,498	$ 254,803,331	$ 318,504,164	$ 382,204,997	$ 445,905,830	$ 509,606,662	$ 573,307,495	$ 637,008,328	$ 700,709,161
3	Less: Accumulated Deferred Income Taxes	$ -	$ -	$ -	$ 22,852,674	$ 50,345,890	$ 77,114,062	$ 103,213,376	$ 128,691,990	$ 113,466,535	$ 97,710,007	$ 81,463,874	$ 65,137,478	$ 48,809,744	$ 32,483,348
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ -	$ -	$ -	$ 868,958,985	$ 777,764,937	$ 687,295,931	$ 597,495,784	$ 508,316,338	$ 459,840,960	$ 411,896,656	$ 364,441,956	$ 317,067,519	$ 269,694,420	$ 222,319,983
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ -	$ -	$ -	$ 92,891,716	$ 83,143,072	$ 73,471,935	$ 63,872,299	$ 54,339,017	$ 49,156,999	$ 44,031,752	$ 38,958,845	$ 33,894,518	$ 28,830,334	$ 23,766,006
8	Annual Depreciation (Line 2)	$ -	$ -	$ -	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833
9	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ -	$ -	$ -	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
10	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ -	$ -	$ -	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
11	Total Operating Expenses (Line 8 + Line 9 + Line 10)	$ -	$ -	$ -	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503
	Revenue Requirement	$ -	$ -	$ -	$ 206,597,218	$ 196,848,575	$ 187,177,438	$ 177,577,802	$ 168,044,519	$ 162,862,501	$ 157,737,255	$ 152,664,348	$ 147,600,021	$ 142,535,836	$ 137,471,509
	NPV	$ 1,539,131,280													
	Discount Rate	5%													
	Depreciation life	15													
	Annual Tax Depreciation - Pollution Control														
	60% Bonus				20.000%	20.000%	20.000%	20.000%	20.000%						
	40% 20year MACRS				3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%
	Annual Tax Depreciation				$ 128,994,186	$ 142,252,878	$ 140,181,327	$ 138,270,302	$ 136,496,871	$ 20,199,534	$ 18,682,180	$ 17,283,310	$ 17,053,987	$ 17,050,165	$ 17,053,987
	Cumulative Tax Depreciation				$ 128,994,186	$ 271,247,064	$ 411,428,391	$ 549,698,693	$ 686,195,563	$ 706,395,097	$ 725,077,277	$ 742,360,587	$ 759,414,574	$ 776,464,739	$ 793,518,726
	Timing Difference				$ 65,293,354	$ 143,845,399	$ 220,325,892	$ 294,895,361	$ 367,691,399	$ 324,190,100	$ 279,171,448	$ 232,753,925	$ 186,107,079	$ 139,456,411	$ 92,809,565
	Accumulated Deferred Tax				$ 22,852,674	$ 50,345,890	$ 77,114,062	$ 103,213,376	$ 128,691,990	$ 113,466,535	$ 97,710,007	$ 81,463,874	$ 65,137,478	$ 48,809,744	$ 32,483,348
	Jurisdictional Calculation				$ 177,735,861										

Big Sandy financing analysis

	Traditional Return on Rate Base	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
	Cumulative Construction Expenditures										
	AFUDC										
	Preliminary Scrubber Analysis2004-2006										
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492
2	Less: Accumulated Depreciation	$ 764,409,994	$ 828,110,826	$ 891,811,659	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492	$ 955,512,492
3	Less: Accumulated Deferred Income Taxes	$ 16,155,614	$ (170,782)	$ (16,498,516)	$ (32,824,912)	$ (26,857,354)	$ (20,888,459)	$ (14,920,901)	$ (8,952,005)	$ (2,984,448)	$ -
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 174,946,884	$ 127,572,448	$ 80,199,348	$ 32,824,912	$ 26,857,354	$ 20,888,459	$ 14,920,901	$ 8,952,005	$ 2,984,448	$ -
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 18,701,822	$ 13,637,495	$ 8,573,310	$ 3,508,983	$ 2,871,051	$ 2,232,976	$ 1,595,044	$ 956,969	$ 319,037	$ -
8	Annual Depreciation (Line 2)	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ 63,700,833	$ -	$ -	$ -	$ -	$ -	$ -
9	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
10	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
11	Total Operating Expenses (Line 8 + Line 9 + Line 10)	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 113,705,503	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670
	Revenue Requirement	$ 132,407,325	$ 127,342,997	$ 122,278,813	$ 117,214,486	$ 52,875,721	$ 52,237,646	$ 51,599,714	$ 50,961,639	$ 50,323,707	$ 50,004,670
	NPV										
	Discount Rate										
	Depreciation life										
	Annual Tax Depreciation - Pollution Control										
	60% Bonus										
	40% 20year MACRS	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%
	Annual Tax Depreciation	$ 17,050,165	$ 17,053,987	$ 17,050,165	$ 17,053,987	$ 17,050,165	$ 17,053,987	$ 17,050,165	$ 17,053,987	$ 17,050,165	$ 8,526,993
	Cumulative Tax Depreciation	$ 810,568,891	$ 827,622,878	$ 844,673,043	$ 861,727,030	$ 878,777,195	$ 895,831,182	$ 912,881,347	$ 929,935,334	$ 946,985,499	$ 955,512,492
	Timing Difference	$ 46,158,897	$ (487,948)	$ (47,138,616)	$ (93,785,462)	$ (76,735,297)	$ (59,681,310)	$ (42,631,145)	$ (25,577,158)	$ (8,526,993)	$ -
	Accumulated Deferred Tax	$ 16,155,614	$ (170,782)	$ (16,498,516)	$ (32,824,912)	$ (26,857,354)	$ (20,888,459)	$ (14,920,901)	$ (8,952,005)	$ (2,984,448)	$ -

Jurisdictional Calculation

Big Sandy financing analysis

	CWIP at WACC	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
	Cumulative Construction Expenditures	$ 92,368,000	$ 235,638,000	$ 455,916,000	$ 839,325,067			
	AFUDC	$ -	$ -	$ -	$ -			
	Preliminary Scrubber Analysis2004-2006	$ 15,212,425	$ 15,212,425	$ 15,212,425	$ 15,212,425			
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ -	$ -	$ -	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492
2	Less: Accumulated Depreciation	$ -	$ -	$ -	$ 56,969,166	$ 113,938,332	$ 170,907,498	$ 227,876,665
3	Less: Accumulated Deferred Income Taxes	$ -	$ -	$ -	$ 20,437,688	$ 45,025,523	$ 68,964,936	$ 92,306,171
4	Plus: CWIP Earning a Return	$ 107,580,425	$ 250,850,425	$ 471,128,425	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 107,580,425	$ 250,850,425	$ 471,128,425	$ 777,130,638	$ 695,573,636	$ 614,665,058	$ 534,354,656
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 11,500,347	$ 26,815,910	$ 50,363,629	$ 83,075,265	$ 74,356,822	$ 65,707,695	$ 57,122,513
8	Annual Depreciation (Line 2)	$ -	$ -	$ -	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ 56,969,166
9	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ -	$ -	$ -	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
10	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ -	$ -	$ -	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
11	Total Operating Expenses (Line 8 + Line 9 + Line 10)	$ -	$ -	$ -	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 106,973,836
	Revenue Requirement	$ 11,500,347	$ 26,815,910	$ 50,363,629	$ 190,049,101	$ 181,330,658	$ 172,681,531	$ 164,096,349
	NPV	$ 1,512,150,440						
	Discount Rate	5%						
	Depreciation life	15						
	Annual Tax Depreciation - Pollution Control							
	60% Bonus				20.000%	20.000%	20.000%	20.000%
	40% 20year MACRS				3.750%	7.219%	6.677%	6.177%
	Annual Tax Depreciation				$ 115,362,561	$ 127,220,124	$ 125,367,486	$ 123,658,411
	Cumulative Tax Depreciation				$ 115,362,561	$ 242,582,685	$ 367,950,171	$ 491,608,583
	Timing Difference				$ 58,393,395	$ 128,644,353	$ 197,042,673	$ 263,731,918
	Accumulated Deferred Tax				$ 20,437,688	$ 45,025,523	$ 68,964,936	$ 92,306,171
	Jurisdictional Calculation				$ 163,148,995			

	CWIP at WACC	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
	Cumulative Construction Expenditures							
	AFUDC							
	Preliminary Scrubber Analysis2004-2006							
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492
2	Less: Accumulated Depreciation	$ 284,845,831	$ 341,814,997	$ 398,784,163	$ 455,753,329	$ 512,722,495	$ 569,691,661	$ 626,660,827
3	Less: Accumulated Deferred Income Taxes	$ 115,092,300	$ 101,475,814	$ 87,384,377	$ 72,855,075	$ 58,253,992	$ 43,651,712	$ 29,050,629
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 454,599,362	$ 411,246,681	$ 368,368,952	$ 325,929,088	$ 283,561,005	$ 241,194,119	$ 198,826,036
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 48,596,672	$ 43,962,270	$ 39,378,641	$ 34,841,819	$ 30,312,671	$ 25,783,651	$ 21,254,503
8	Annual Depreciation (Line 2)	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ 56,969,166
9	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
10	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
11	Total Operating Expenses (Line 8 + Line 9 + Line 10)	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 106,973,836
	Revenue Requirement	$ 155,570,508	$ 150,936,106	$ 146,352,477	$ 141,815,656	$ 137,286,508	$ 132,757,487	$ 128,228,339
	NPV							
	Discount Rate							
	Depreciation life							
	Annual Tax Depreciation - Pollution Control							
	60% Bonus	20.000%						
	40% 20year MACRS	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%
	Annual Tax Depreciation	$ 122,072,390	$ 18,064,923	$ 16,707,917	$ 15,456,874	$ 15,251,785	$ 15,248,367	$ 15,251,785
	Cumulative Tax Depreciation	$ 613,680,973	$ 631,745,895	$ 648,453,812	$ 663,910,686	$ 679,162,472	$ 694,410,839	$ 709,662,624
	Timing Difference	$ 328,835,142	$ 289,930,898	$ 249,669,649	$ 208,157,357	$ 166,439,976	$ 124,719,177	$ 83,001,796
	Accumulated Deferred Tax	$ 115,092,300	$ 101,475,814	$ 87,384,377	$ 72,855,075	$ 58,253,992	$ 43,651,712	$ 29,050,629
	Jurisdictional Calculation							

Big Sandy financing analysis

	CWIP at WACC	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
	Cumulative Construction Expenditures										
	AFUDC										
	Preliminary Scrubber Analysis2004-2006										
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492
2	Less: Accumulated Depreciation	$ 683,629,994	$ 740,599,160	$ 797,568,326	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492	$ 854,537,492
3	Less: Accumulated Deferred Income Taxes	$ 14,448,349	$ (152,734)	$ (14,755,014)	$ (29,356,097)	$ (24,019,169)	$ (18,681,044)	$ (13,344,116)	$ (8,005,991)	$ (2,669,062)	$ -
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 156,459,149	$ 114,091,067	$ 71,724,180	$ 29,356,097	$ 24,019,169	$ 18,681,044	$ 13,344,116	$ 8,005,991	$ 2,669,062	$ -
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%	10.69%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 16,725,483	$ 12,196,335	$ 7,667,315	$ 3,138,167	$ 2,567,649	$ 1,997,004	$ 1,426,486	$ 855,840	$ 285,323	$ -
8	Annual Depreciation (Line 2)	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ 56,969,166	$ -	$ -	$ -	$ -	$ -	$ -
9	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
10	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
11	Total Operating Expenses (Line 8 + Line 9 + Line 10)	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 106,973,836	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670
	Revenue Requirement	$ 123,699,319	$ 119,170,171	$ 114,641,151	$ 110,112,003	$ 52,572,319	$ 52,001,674	$ 51,431,156	$ 50,860,510	$ 50,289,993	$ 50,004,670
	NPV										
	Discount Rate										
	Depreciation life										
	Annual Tax Depreciation - Pollution Control										
	60% Bonus										
	40% 20year MACRS	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%
	Annual Tax Depreciation	$ 15,248,367	$ 15,251,785	$ 15,248,367	$ 15,251,785	$ 15,248,367	$ 15,251,785	$ 15,248,367	$ 15,251,785	$ 15,248,367	$ 7,625,893
	Cumulative Tax Depreciation	$ 724,910,991	$ 740,162,776	$ 755,411,143	$ 770,662,928	$ 785,911,295	$ 801,163,080	$ 816,411,447	$ 831,663,232	$ 846,911,599	$ 854,537,492
	Timing Difference	$ 41,280,997	$ (436,384)	$ (42,157,183)	$ (83,874,564)	$ (68,626,197)	$ (53,374,412)	$ (38,126,045)	$ (22,874,260)	$ (7,625,893)	$ -
	Accumulated Deferred Tax	$ 14,448,349	$ (152,734)	$ (14,755,014)	$ (29,356,097)	$ (24,019,169)	$ (18,681,044)	$ (13,344,116)	$ (8,005,991)	$ (2,669,062)	$ -

Jurisdictional Calculation

Big Sandy financing analysis

	Securitized Mortgage Financing	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
	Cumulative Construction Expenditures	$ 92,368,000	$ 235,638,000	$ 455,916,000	$ 839,325,067			
	AFUDC	$ 5,977,000	$ 20,561,000	$ 51,993,000	$ 100,975,000			
	Preliminary Scrubber Analysis2004-2006	$ 15,212,425	$ 15,212,425	$ 15,212,425	$ 15,212,425			
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ -	$ -	$ -	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485
2	Less: Accumulated Depreciation	$ -	$ -	$ -	$ 27,967,699	$ 55,935,398	$ 83,903,097	$ 111,870,796
3	Less: Accumulated Deferred Income Taxes	$ -	$ -	$ -	$ 10,033,412	$ 22,104,243	$ 33,856,745	$ 45,315,587
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ -	$ -	$ -	$ 381,514,374	$ 341,475,844	$ 301,755,642	$ 262,329,102
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	16.55%	16.55%	16.55%	16.55%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ -	$ -	$ -	$ 63,141,010	$ 56,514,594	$ 49,940,861	$ 43,415,729
8	Mortgage Payment				$ 44,898,636	$ 44,898,636	$ 44,898,636	$ 44,898,636
9	Annual Depreciation (Line 2)	$ -	$ -	$ -	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ 27,967,699
10	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ -	$ -	$ -	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
11	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ -	$ -	$ -	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
12	Total Operating Expenses (Line 8 + Line 9 + Line 10 + Line 11)	$ -	$ -	$ -	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 122,871,005
	Revenue Requirement	$ -	$ -	$ -	$ 186,012,016	$ 179,385,599	$ 172,811,866	$ 166,286,734
	NPV	$ 1,483,706,536						
	Discount Rate	5%						
	Depreciation life	15						
	Annual Tax Depreciation - Pollution Control							
	60% Bonus				20.000%	20.000%	20.000%	20.000%
	40% 20year MACRS				3.750%	7.219%	6.677%	6.177%
	Annual Tax Depreciation				$ 55,634,590	$ 62,455,787	$ 61,546,278	$ 60,707,247
	Cumulative Tax Depreciation				$ 55,634,590	$ 119,090,378	$ 180,636,655	$ 241,343,902
	Timing Difference				$ 28,666,891	$ 63,154,080	$ 96,733,558	$ 129,473,106
	Accumulated Deferred Tax				$ 10,033,412	$ 22,104,243	$ 33,856,745	$ 45,315,587
	Jurisdictional Calculation				$ 159,590,377			

	Securitized Mortgage Financing	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485
2	Less: Accumulated Depreciation	$ 139,838,495	$ 167,806,194	$ 195,773,893	$ 223,741,592	$ 251,709,291	$ 279,676,990	$ 307,644,689
3	Less: Accumulated Deferred Income Taxes	$ 56,501,912	$ 49,817,212	$ 42,899,346	$ 35,766,520	$ 28,598,454	$ 21,429,802	$ 14,261,737
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 223,175,078	$ 201,692,079	$ 180,842,246	$ 160,007,373	$ 139,207,739	$ 118,408,693	$ 97,609,059
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 36,935,699	$ 33,413,341	$ 29,929,573	$ 26,481,380	$ 23,039,020	$ 19,596,757	$ 16,154,397
8	Mortgage Payment	$ 44,898,636	$ 44,898,636	$ 44,898,636	$ 44,898,636	$ 44,898,636	$ 44,898,636	$ 44,898,636
9	Annual Depreciation (Line 2)	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ 27,967,699
10	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
11	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
12	Total Operating Expenses (Line 8 + Line 9 + Line 10 + Line 11)	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 122,871,005
	Revenue Requirement	$ 159,806,704	$ 156,284,346	$ 152,800,578	$ 149,352,386	$ 145,910,025	$ 142,467,763	$ 139,025,402
	60% Bonus	20.000%						
	40% 20year MACRS	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%
	Annual Tax Depreciation	$ 59,928,626	$ 8,868,557	$ 8,202,367	$ 7,588,196	$ 7,487,512	$ 7,485,834	$ 7,487,512
	Cumulative Tax Depreciation	$ 301,272,528	$ 310,141,086	$ 318,343,452	$ 325,931,648	$ 333,419,161	$ 340,904,995	$ 348,392,507
	Timing Difference	$ 161,434,033	$ 142,334,892	$ 122,569,559	$ 102,190,057	$ 81,709,870	$ 61,228,005	$ 40,747,819
	Accumulated Deferred Tax	$ 56,501,912	$ 49,817,212	$ 42,899,346	$ 35,766,520	$ 28,598,454	$ 21,429,802	$ 14,261,737

Big Sandy financing analysis

	Securitized Mortgage Financing	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
	Cumulative Construction Expenditures										
	AFUDC										
	Preliminary Scrubber Analysis2004-2006										
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485
2	Less: Accumulated Depreciation	$ 335,612,388	$ 363,580,087	$ 391,547,786	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485	$ 419,515,485
3	Less: Accumulated Deferred Income Taxes	$ 7,093,084	$ (74,981)	$ (7,243,634)	$ (14,411,699)	$ (11,791,657)	$ (9,171,028)	$ (6,550,986)	$ (3,930,357)	$ (1,310,315)	$ -
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 76,810,013	$ 56,010,379	$ 35,211,333	$ 14,411,699	$ 11,791,657	$ 9,171,028	$ 6,550,986	$ 3,930,357	$ 1,310,315	$ -
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 12,712,134	$ 9,269,774	$ 5,827,511	$ 2,385,151	$ 1,951,531	$ 1,517,814	$ 1,084,195	$ 650,478	$ 216,858	$ -
8	Mortgage Payment	$ 44,898,636	$ 44,898,636	$ 44,898,636	$ 44,898,636	$ -	$ -	$ -	$ -	$ -	$ -
9	Annual Depreciation (Line 2)	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ 27,967,699	$ -	$ -	$ -	$ -	$ -	$ -
10	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
11	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
12	Total Operating Expenses (Line 8 + Line 9 + Line 10 + Line 11)	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 122,871,005	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670
	Revenue Requirement	$ 135,583,139	$ 132,140,779	$ 128,698,516	$ 125,256,156	$ 51,956,201	$ 51,522,484	$ 51,088,865	$ 50,655,148	$ 50,221,528	$ 50,004,670
	NPV										
	Discount Rate										
	Depreciation life										
	Annual Tax Depreciation - Pollution Control										
	60% Bonus										
	40% 20year MACRS	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%
	Annual Tax Depreciation	$ 7,485,834	$ 7,487,512	$ 7,485,834	$ 7,487,512	$ 7,485,834	$ 7,487,512	$ 7,485,834	$ 7,487,512	$ 7,485,834	$ 3,743,756
	Cumulative Tax Depreciation	$ 355,878,342	$ 363,365,854	$ 370,851,688	$ 378,339,201	$ 385,825,035	$ 393,312,547	$ 400,798,382	$ 408,285,894	$ 415,771,728	$ 419,515,485
	Timing Difference	$ 20,265,954	$ (214,233)	$ (20,696,097)	$ (41,176,284)	$ (33,690,450)	$ (26,202,937)	$ (18,717,103)	$ (11,229,590)	$ (3,743,756)	$ -
	Accumulated Deferred Tax	$ 7,093,084	$ (74,981)	$ (7,243,634)	$ (14,411,699)	$ (11,791,657)	$ (9,171,028)	$ (6,550,986)	$ (3,930,357)	$ (1,310,315)	$ -

Jurisdictional Calculation

Big Sandy financing analysis

	CWIP at WACC with Securitized Mortgage Financing	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11	Year 12	Year 13	Year 14
	Cumulative Construction Expenditures	$ 92,368,000	$ 235,638,000	$ 455,916,000	$ 839,325,067										
	AFUDC	$ -	$ -	$ -	$ -										
	Preliminary Scrubber Analysis2004-2006	$ 15,212,425	$ 15,212,425	$ 15,212,425	$ 15,212,425										
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ -	$ -	$ -	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651
2	Less: Accumulated Depreciation	$ -	$ -	$ -	$ 25,012,177	$ 50,024,353	$ 75,036,530	$ 100,048,707	$ 125,060,884	$ 150,073,060	$ 175,085,237	$ 200,097,414	$ 225,109,591	$ 250,121,767	$ 275,133,944
3	Less: Accumulated Deferred Income Taxes	$ -	$ -	$ -	$ 8,973,118	$ 19,768,349	$ 30,278,891	$ 40,526,805	$ 50,531,000	$ 44,552,715	$ 38,365,903	$ 31,986,847	$ 25,576,276	$ 19,165,180	$ 12,754,609
4	Plus: CWIP Earning a Return	$ 107,580,425	$ 250,850,425	$ 471,128,425	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 107,580,425	$ 250,850,425	$ 471,128,425	$ 341,197,356	$ 305,389,949	$ 269,867,230	$ 234,607,139	$ 199,590,767	$ 180,556,876	$ 161,731,511	$ 143,098,390	$ 124,496,784	$ 105,895,704	$ 87,294,098
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	10.69%	10.69%	10.69%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 11,500,347	$ 26,815,910	$ 50,363,629	$ 56,468,504	$ 50,542,342	$ 44,663,296	$ 38,827,716	$ 33,032,472	$ 29,882,344	$ 26,766,727	$ 23,682,927	$ 20,604,342	$ 17,525,845	$ 14,447,260
8	Mortgage Payment				$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745
9	Annual Depreciation (Line 2)	$ -	$ -	$ -	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177
10	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ -	$ -	$ -	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
11	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ -	$ -	$ -	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
12	Total Operating Expenses (Line 8 + Line 9 + Line 10 + Line 11)	$ -	$ -	$ -	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592
	Revenue Requirement	$ 11,500,347	$ 26,815,910	$ 50,363,629	$ 171,639,096	$ 165,712,934	$ 159,833,889	$ 153,998,308	$ 148,203,054	$ 145,052,936	$ 141,937,319	$ 138,853,519	$ 135,774,934	$ 132,696,437	$ 129,617,853
	NPV	$ 1,462,581,247													
	Discount Rate	5%													
	Depreciation life	15													
	Annual Tax Depreciation - Pollution Control														
	60% Bonus				20.000%	20.000%	20.000%	20.000%	20.000%						
	40% 20year MACRS				3.750%	7.219%	6.677%	6.177%	5.713%	5.285%	4.888%	4.522%	4.462%	4.461%	4.462%
	Annual Tax Depreciation				$ 50,649,658	$ 55,855,692	$ 55,042,296	$ 54,291,931	$ 53,595,592	$ 7,931,361	$ 7,335,571	$ 6,786,304	$ 6,696,260	$ 6,694,759	$ 6,696,260
	Cumulative Tax Depreciation				$ 50,649,658	$ 106,505,350	$ 161,547,647	$ 215,839,578	$ 269,435,170	$ 277,366,531	$ 284,702,102	$ 291,488,406	$ 298,184,666	$ 304,879,425	$ 311,575,685
	Timing Difference				$ 25,637,481	$ 56,480,997	$ 86,511,116	$ 115,790,871	$ 144,374,286	$ 127,293,471	$ 109,616,865	$ 91,390,992	$ 73,075,075	$ 54,757,658	$ 36,441,741
	Accumulated Deferred Tax				$ 8,973,118	$ 19,768,349	$ 30,278,891	$ 40,526,805	$ 50,531,000	$ 44,552,715	$ 38,365,903	$ 31,986,847	$ 25,576,276	$ 19,165,180	$ 12,754,609
	Jurisdictional Calculation				$ 146,920,908										

Big Sandy financing analysis

	CWIP at WACC with Securitized Mortgage Financing	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20	Year 21	Year 22	Year 23	Year 24
	Cumulative Construction Expenditures										
	AFUDC										
	Preliminary Scrubber Analysis2004-2006										
1	Utility Plant Installed Net (Exhibit LPM-1, Line 5)	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651
2	Less: Accumulated Depreciation	$ 300,146,121	$ 325,158,298	$ 350,170,474	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651	$ 375,182,651
3	Less: Accumulated Deferred Income Taxes	$ 6,343,513	$ (67,058)	$ (6,478,154)	$ (12,888,725)	$ (10,545,559)	$ (8,201,868)	$ (5,858,702)	$ (3,515,011)	$ (1,171,845)	$ -
4	Plus: CWIP Earning a Return	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Net Utility Plant (Line 1- Line 2 - Line 3)	$ 68,693,017	$ 50,091,411	$ 31,490,331	$ 12,888,725	$ 10,545,559	$ 8,201,868	$ 5,858,702	$ 3,515,011	$ 1,171,845	$ -
6	Annual Weighted Average Cost of Capital (Exhibit LPM-3, L5, C8)	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%
7	Annual Return on Rate Base (Line 4 X Line 5)	$ 11,368,763	$ 8,290,179	$ 5,211,681	$ 2,133,097	$ 1,745,301	$ 1,357,417	$ 969,621	$ 581,738	$ 193,942	$ -
8	Mortgage Payment	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ 40,153,745	$ -	$ -	$ -	$ -	$ -	$ -
9	Annual Depreciation (Line 2)	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ 25,012,177	$ -	$ -	$ -	$ -	$ -	$ -
10	Annual Property Tax Expense (Exhibit LPM-4, Line 5)	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670	$ 1,337,670
11	Annual Non-Fuel O&M Expense (Exhibit LPM-1, Line 8)	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000	$ 48,667,000
12	Total Operating Expenses (Line 8 + Line 9 + Line 10 + Line 11)	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 115,170,592	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670	$ 50,004,670
	Revenue Requirement	$ 126,539,355	$ 123,460,771	$ 120,382,273	$ 117,303,689	$ 51,749,971	$ 51,362,087	$ 50,974,291	$ 50,586,408	$ 50,198,612	$ 50,004,670
	NPV										
	Discount Rate										
	Depreciation life										
	Annual Tax Depreciation - Pollution Control										
	60% Bonus										
	40% 20year MACRS	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	4.462%	4.461%	2.231%
	Annual Tax Depreciation	$ 6,694,759	$ 6,696,260	$ 6,694,759	$ 6,696,260	$ 6,694,759	$ 6,696,260	$ 6,694,759	$ 6,696,260	$ 6,694,759	$ 3,348,130
	Cumulative Tax Depreciation	$ 318,270,445	$ 324,966,704	$ 331,661,464	$ 338,357,724	$ 345,052,483	$ 351,748,743	$ 358,443,502	$ 365,139,762	$ 371,834,521	$ 375,182,651
	Timing Difference	$ 18,124,324	$ (191,593)	$ (18,509,011)	$ (36,824,928)	$ (30,130,168)	$ (23,433,908)	$ (16,739,149)	$ (10,042,889)	$ (3,348,130)	$ -
	Accumulated Deferred Tax	$ 6,343,513	$ (67,058)	$ (6,478,154)	$ (12,888,725)	$ (10,545,559)	$ (8,201,868)	$ (5,858,702)	$ (3,515,011)	$ (1,171,845)	$ -

Jurisdictional Calculation

Kentucky Power Company

REQUEST

Please describe specifically how the Company computes its AFUDC rate and then applies the AFUDC rate on a monthly basis for Kentucky jurisdictional purposes. Provide a mathematical example and provide a copy of all source documents relied on by the Company for its methodology, such as, but not limited to, the FERC USOA.

RESPONSE

The Company calculates its AFUDC rate on a monthly basis using the formula specified in the FERC Uniform System of Accounts, Electric Plant Instructions, Section 3. Components of Construction Cost, Item (17) AFUDC. The balances for long-term debt and common equity are the actual book balances at the end of the prior month. The cost rate for long-term debt is the cost for the prior month. The cost rate for common equity is the last rate of return on common equity approved by the Kentucky Commission. The average short-term debt balance and related cost rate and the balance for construction work in progress is based on the prior month. Attachment 1 provides an example of the AFUDC rate calculation for June 2011.

AFUDC is calculated on construction projects using the prior month ending balance plus one half the current month charges. AFUDC is charged on construction projects during the period of actual construction. One half month AFUDC is taken during the in service month. Projects that are excluded from the AFUDC calculation include construction expenditures that are reimbursed, construction work in progress that is currently in rate base, contractor's retention, and purchases of plant and equipment that require no construction period. Attachment 2 provides an example of the AFUDC calculation for generation projects for June 2011.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Computation of AFUDC Rate
June 2011

Line No.	Description	Amount
1	**AFUDC Rate - Simple (AFUDC_S)**	
2	Gross Rate for Borrowed Funds Ai=s(S/W)+d(D/D+P+C)(1-S/W)	3.51%
3	Gross Rate for Other Funds Ae=[1-S/W][p(P/D+P+C)+c(C/D+P+C)]	4.76%
4	Total AFUDC Simple Rate, AFUDC_S	8.27%
5	**AFUDC Rate - Compound (Semi-Annual), Maximum Rate (AFUDC_C)**	
6	Gross Rate for Borrowed Funds - Maximum Rate Ai_C = (Ai/2)+((1+Ai/2)*Ai/2)	3.54%
7	Gross Rate for Other Funds - Maximum Rate Ae_C = (Ae/2)+((1+Ae/2)*Ae/2)	4.82%
8	Total AFUDC Maximum Rate, AFUDC_C = Ai_C + Ae_C	8.36%
9	AFUDC_C=((1*AFUDC_S)/2)+((1+(AFUDC_S/2))*(AFUDC_S/2))	
10	Ai=Gross allowance for borrowed funds used during construction rate.	
11	Ae=Allowance for other funds used during construction rate.	
12	S=Prior month average short-term debt balance. ($000)	0
13	s=Short term debt interest rate.	0.00000000%
14	D=Prior month ending Long-term debt balance. ($000)	545,547,181
15	d=Long-term debt interest rate.	6.42450500%
16	P=Prior month ending Preferred stock balance. ($000)	0
17	p=Preferred stock cost rate.	0.00000000%
18	C=Prior month ending Common Equity balance. ($000)	453,035,100
19	c=Common equity cost rate.	10.50000000%
20	W=Average balance in construction work in progress. ($000)	31,698,925
21	S/W=	0.00%
22	1-S/W=	100.00%
23	D+P+C= Total capitalization. ($000)	998,582,281

AFUDC Calcul[illegible] .eport

American Electric Power
Kentucky Power - Gen

Selected Month: Jun 2011

No Subtotal Work Order Number	Beginning AFUDC Base	Base Adjustments	1/2 Current Month Chgs	Compound AFUDC	Eligible Base Factor	Total AFUDC Base	AFUDC Debt	AFUDC Equity	Total AFUDC	Input Debt Adj	Input Equity Adj
KEPCo Whsle AFUDC		Debt Rate:	.00290371		Equity Rate:	.00393085	Total Rate: 0.00683456				
NO SUBTOTAL											
41076081	$509,474.12	$0.00	$0.00	$3,458.05	1.0	$512,932.17	$1,489.41	$2,016.26	$3,505.67	$0.00	$0.00
41123033	$1,527,713.71	($22,890.00)	$900.58	$9,219.83	1.0	$1,514,944.12	$4,398.96	$5,955.02	$10,353.98	$0.00	$0.00
41287503	$38,418.32	$0.00	$571.71	$117.97	1.0	$39,108.00	$113.56	$153.73	$267.29	$0.00	$0.00
41330504	$104,491.71	$0.00	$0.00	$715.03	1.0	$105,206.74	$305.49	$413.55	$719.04	$0.00	$0.00
41401940	$0.00	$0.00	$0.00	$0.00	1.0	$0.00	($186.09)	($254.58)	($440.67)	$0.00	$0.00
41401943	$0.00	$0.00	$0.00	$0.00	1.0	$0.00	($7.12)	($9.73)	($16.85)	$0.00	$0.00
41401944	$0.00	$0.00	$0.00	$0.00	1.0	$0.00	($7.12)	($9.73)	($16.85)	$0.00	$0.00
41401946	$2,463.16	$0.00	$13,687.63	$16.85	1.0	$16,167.64	$46.95	$63.55	$110.50	$0.00	$0.00
41417430	$23,621.65	$0.00	$0.00	$161.10	1.0	$23,782.75	$69.06	$93.49	$162.55	$0.00	$0.00
41423092	$11,127.00	$0.00	$0.00	$75.81	1.0	$11,202.81	$32.53	$44.04	$76.57	$0.00	$0.00
41423097	$29,188.86	$0.00	$0.00	$199.40	1.0	$29,388.26	$85.33	$115.52	$200.85	$0.00	$0.00
41502972	$3,376.70	$0.00	$0.00	$23.10	1.0	$3,399.80	$9.87	$13.36	$23.23	$0.00	$0.00
41538152	$72.30	$0.00	$47.15	$0.19	1.0	$119.64	$0.35	$0.47	$0.82	$0.00	$0.00
41553510	$64,211.76	$0.00	$0.00	$439.39	1.0	$64,651.15	$187.73	$254.13	$441.86	$0.00	$0.00
41553538	$49,237.02	$0.00	$0.00	$336.92	1.0	$49,573.94	$143.95	$194.87	$338.82	$0.00	$0.00
41560928	$191,902.64	$0.00	$1,066.25	$1,313.18	1.0	$194,282.07	$564.14	$763.69	$1,327.83	$0.00	$0.00
41574123	$228,283.25	$0.00	$1,339.03	$1,518.75	1.0	$231,141.03	$671.17	$908.58	$1,579.75	$0.00	$0.00
41580551	$7,966.60	$0.00	$3,388.38	$53.52	1.0	$11,408.50	$33.13	$44.85	$77.98	$0.00	$0.00
41589878	$91,532.22	$0.00	$0.00	$605.51	1.0	$92,137.73	$267.54	$362.18	$629.72	$0.00	$0.00
41591355	$62,997.45	$0.00	$0.00	$431.01	1.0	$63,428.46	$184.18	$249.33	$433.51	$0.00	$0.00
41592547	$110,545.69	$0.00	$2,652.17	$701.27	1.0	$113,899.13	$330.73	$447.72	$778.45	$0.00	$0.00
41626803	$0.00	$0.00	$11,504.43	$0.00	1.0	$11,504.43	$33.41	$45.22	$78.63	$0.00	$0.00
41631012	$7,293.16	$0.00	$0.00	$49.90	1.0	$7,343.06	$21.32	$28.86	$50.18	$0.00	$0.00
41634217	$0.00	$0.00	$102,019.86	$0.00	1.0	$102,019.86	$296.24	$401.02	$697.26	$0.00	$0.00
41636072	$9,825.55	$0.00	$159.28	$60.31	1.0	$10,045.14	$29.17	$39.49	$68.66	$0.00	$0.00
41640129	$192.96	$0.00	$0.00	$1.32	1.0	$194.28	$0.56	$0.76	$1.32	$0.00	$0.00
41649751	$70,013.24	$0.00	$1.00	$476.93	1.0	$70,491.17	$204.69	$277.09	$481.78	$0.00	$0.00
41652496	$69,498.34	$0.00	$0.00	$475.58	1.0	$69,973.92	$203.18	$275.06	$478.24	$0.00	$0.00
41660459	$15,492.42	$0.00	$0.00	$102.69	1.0	$15,595.11	$45.28	$61.30	$106.58	$0.00	$0.00
41670627	$4,100.18	$0.00	$1,010.65	$10.89	1.0	$5,121.72	$14.87	$20.13	$35.00	$0.00	$0.00
41678054	$0.00	$0.00	$0.00	$0.00	1.0	$0.00	($19.81)	($27.08)	($46.89)	$0.00	$0.00

KPSC Case No. 2011-00401
KIUC's First Set of Data Requests
Item No. 39
Attachment 2
Page 1 of 2

WO Control - 3

01/24/2012, 16:59:00

AFUDC Calcul... Report

American Electric Power
Kentucky Power - Gen

Selected Month: Jun 2011

No Subtotal Work Order Number	Beginning AFUDC Base	Base Adjustments	1/2 Current Month Chgs	Compound AFUDC	Eligible Base Factor	Total AFUDC Base	AFUDC Debt	AFUDC Equity	Total AFUDC	Input Debt Adj	Input Equity Adj
KEPCo Whsle AFUDC			Debt Rate: .00290371		Equity Rate:	.00393085	Total Rate: 0.00683456				
NO SUBTOTAL											
41678435	$3,563.36	$0.00	$879.91	$24.36	1.0	$4,467.63	$12.97	$17.56	$30.53	$0.00	$0.00
41679370	$0.00	$0.00	$0.00	$0.00	1.0	$0.00	($241.68)	($330.38)	($572.06)	$0.00	$0.00
41683423	$2,180.61	$0.00	$10,615.77	$5.80	1.0	$12,802.18	$18.59	$25.16	$43.75	$0.00	$0.00
41687836	$4,441.22	$0.00	$3,318.92	$11.79	1.0	$7,771.93	$22.57	$30.55	$53.12	$0.00	$0.00
41694511	$45.07	$0.00	$2,842.60	$0.12	1.0	$2,887.79	$8.39	$11.35	$19.74	$0.00	$0.00
41701267	$0.00	$0.00	$950.51	$0.00	1.0	$950.51	$2.76	$3.74	$6.50	$0.00	$0.00
41703781	$0.00	$0.00	$112.24	$0.00	1.0	$112.24	$0.33	$0.44	$0.77	$0.00	$0.00
41708234	$0.00	$0.00	$735.00	$0.00	1.0	$735.00	$2.13	$2.89	$5.02	$0.00	$0.00
41710888	$0.00	$0.00	$579.38	$0.00	1.0	$579.38	$0.84	$1.14	$1.98	$0.00	$0.00
W0010615	$197,611.00	$0.00	$510.24	$1,344.89	1.0	$199,466.13	$579.19	$784.07	$1,363.26	$0.00	$0.00
X1169760	$294,671.08	$0.00	$0.00	$2,016.41	1.0	$296,687.49	$430.75	$583.12	$1,013.87	$0.00	$0.00
X1169762	$696,963.98	$0.00	$0.00	$4,769.27	1.0	$701,733.25	$1,018.82	$1,379.21	$2,398.03	$0.00	$0.00
X1176260	$2,332.33	$0.00	$215.34	$14.16	1.0	$2,561.83	$7.44	$10.07	$17.51	$0.00	$0.00
X1176270	$3,404.68	$0.00	$464.35	$21.52	1.0	$3,890.55	$11.30	$15.29	$26.59	$0.00	$0.00
X1178570	$393,917.18	$0.00	$152.90	$2,512.92	1.0	$396,583.00	$575.78	$779.46	$1,355.24	$0.00	$0.00
X1178650	$2,080.00	$0.00	$65.83	$12.60	1.0	$2,158.43	$6.27	$8.48	$14.75	$0.00	$0.00
X1178660	$2,127.84	$0.00	$65.83	$12.83	1.0	$2,206.50	$6.41	$8.67	$15.08	$0.00	$0.00
NO SUBTOTAL Total:	$4,836,378.36	($22,890.00)	$159,856.94	$31,311.17		$5,004,656.47	$12,025.52	$16,272.97	$28,298.49	$0.00	$0.00
Kentucky Power - Gen Total:	$4,836,378.36	($22,890.00)	$159,856.94	$31,311.17		$5,004,656.47	$12,025.52	$16,272.97	$28,298.49	$0.00	$0.00
Grand Total:	$4,836,378.36	($22,890.00)	$159,856.94	$31,311.17		$5,004,656.47	$12,025.52	$16,272.97	$28,298.49	$0.00	$0.00

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Attachment 2
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Kentucky Power Company

REQUEST

Please provide a schedule (in excel, with formulas intact), by month for the period beginning with the effective date of new rates in Case No. 2009-00459 to the present, showing the following information for each retail rate schedule:

a. Total revenues

b. Base rate revenues

c. Amount of fuel revenues in base rates (as used in the computation of the monthly fuel adjustment charge; [F(b)/S(b)*S(m), where m is the current month]).

d. Fuel adjustment revenues

e. ECR revenues

f. ECR factor

g. Revenue amount ("Retail Revenue" used in the computation of R(m) pursuant to Tariff E.S.) subject to the monthly ECR factor (these are the total revenues for the rate schedule used to compute ECR revenues by applying ECR factor).

h. System sales clause revenues

i. DSM revenues

j. Capacity Charge revenues

k. Other revenues included in (a) above.

l. kWh sales

m. number of customers

RESPONSE

a-m. The requested information is attached. Please see enclosed CD for the requested schedule in Excel format.

WITNESS: Lila P Munsey

Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

												Other Revenue			
July 2010	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Residential HEAP	Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$19,005,917	$16,846,657	0.0284	$5,743,600	$171,635	$1,395,442	0.078611	$19,518,732	$526,926	$142,395	$195,020	$17,738	-$147,505	202,239,436	142,666
Small General Service (SGS)	$1,462,734	$1,312,215	0.0284	$337,745	$10,136	$106,609	0.078611	$1,483,216	$30,990	$0	$11,471	$0	-$8,687	11,892,420	22,946
Medium General Service (MGS)	$5,252,991	$4,681,917	0.0284	$1,450,055	$43,312	$382,840	0.078611	$5,291,307	$133,045	$0	$49,230	$0	-$37,354	51,058,273	7,676
Large General Service (LGS)	$5,799,005	$5,140,369	0.0284	$1,827,696	$53,735	$422,118	0.078611	$5,827,487	$167,797	$0	$62,048	$0	-$47,063	64,355,479	851
Quantity Power (QP)	$4,871,814	$4,270,114	0.0284	$1,897,939	$56,805	$354,892	0.078611	$4,732,168	$174,116	$0	$64,545	$0	-$48,658	66,828,850	88
Commercial & Industrial Power - Time of Day (CIPTOD)	$5,751,834	$5,040,432	0.0284	$2,450,453	$73,341	$419,203	0.078611	$5,417,152	$224,803	$0	$57,231	$0	-$63,177	86,283,540	16
Municipal Waterworks (MW)	$52,659	$46,542	0.0284	$17,565	$526	$3,838	0.078611	$58,919	$1,611	$0	$596	$0	-$454	618,469	16
Outdoor Lighting (OL)	$631,733	$575,116	0.0284	$78,684	$2,517	$46,128	0.078611	$586,775	$7,293	$0	$2,621	$0	-$1,942	2,770,562	0
Street Lighting (SL)	$151,779	$140,067	0.0284	$20,981	-$297	$9,954	0.078611	$141,825	$1,882	$0	$714	$0	-$542	738,760	62
Total	$42,980,465	$38,053,428		$13,824,716	$411,710	$3,141,025		$43,057,581	$1,268,463	$142,395	$443,479	$17,738	-$355,382	486,785,789	174,321

[1] Total Revenues (a) are being reported on a billed basis only
[2] DSM Revenues (i) are booked directly to Miscellaneous Revenue, therefore are not included in (a) Total Electric Revenues

Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

August 2010	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	Other Revenue: DSM Revenue[2] (i)	Other Revenue: Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$19,717,244	$19,223,969	0.0284	$5,980,406	-$879,595	$909,857	0.047991	$19,143,371	$237,412	$148,112	$204,256	$21,422	-$81	210,577,689	142,741
Small General Service (SGS)	$1,516,472	$1,472,588	0.0284	$349,220	-$51,363	$69,458	0.047991	$1,457,979	$13,868	$0	$11,927	$0	-$6	12,296,478	23,070
Medium General Service (MGS)	$5,299,627	$5,163,553	0.0284	$1,454,862	-$214,308	$242,849	0.047991	$5,068,728	$57,832	$0	$49,695	$0	$6	51,227,539	7,607
Large General Service (LGS)	$5,971,175	$5,834,254	0.0284	$1,883,170	-$276,170	$273,894	0.047991	$5,707,964	$75,024	$0	$64,319	$0	-$146	66,308,813	857
Quantity Power (QP)	$4,603,573	$4,531,865	0.0284	$1,988,551	-$288,219	$212,436	0.047991	$4,394,913	$80,223	$0	$67,919	$0	-$651	70,019,395	86
Commerical & Industrial Power - Time of Day (CIPTOD)	$11,552,930	$10,690,023	0.0284	$5,599,038	-$270,477	$697,770	0.047991	$10,856,560	$384,901	$0	$131,498	$0	-$80,785	197,149,240	20
Municipal Waterworks (MW)	$38,422	$37,591	0.0284	$12,666	-$1,864	$1,759	0.047991	$36,762	$503	$0	$433	$0	$0	445,992	15
Outdoor Lighting (OL)	$651,686	$628,402	0.0284	$89,567	-$13,209	$29,924	0.047991	$631,951	$3,591	$0	$2,977	$0	$1	3,153,753	0
Street Lighting (SL)	$110,782	$106,981	0.0284	$17,345	-$2,553	$5,073	0.047991	$105,709	$688	$0	$592	$0	$0	610,727	55
Total	$49,461,910	$47,689,226		$17,374,825	-$1,997,758	$2,443,021		$47,403,937	$854,042	$148,112	$533,617	$21,422	-$81,662	611,789,626	174,451

[1] Total Revenues (a) are being reported on a billed basis only
[2] DSM Revenues (i) are booked directly to Miscellaneous Revenue, therefore are not included in (a) Total Electric Revenues

Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

September 2010	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor[3] (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP (k)	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$15,707,839	$16,720,768	0.0284	$5,152,734	-$917,940	$143,728	Various - Prorated	$15,839,505	-$436,097	$128,054	$175,990	$21,418	-$32	181,434,311	142,469
Small General Service (SGS)	$1,350,225	$1,413,913	0.0284	$327,268	-$58,308	$11,697	Various - Prorated	$1,351,867	-$28,253	$0	$11,176	$0	$0	11,523,518	23,122
Medium General Service (MGS)	$4,642,221	$4,917,650	0.0284	$1,378,425	-$245,549	$41,291	Various - Prorated	$4,608,575	-$118,252	$0	$47,080	$0	$0	48,536,105	7,550
Large General Service (LGS)	$5,356,847	$5,738,490	0.0284	$1,850,492	-$329,911	$45,512	Various - Prorated	$5,310,956	-$160,447	$0	$63,203	$0	$0	65,158,152	852
Quantity Power (QP)	$4,039,477	$4,471,588	0.0284	$1,948,284	-$346,362	$30,602	Various - Prorated	$4,008,873	-$182,895	$0	$66,544	$0	$0	68,601,555	86
Commerical & Industrial Power - Time of Day (CIPTOD)	$13,460,697	$14,781,381	0.0284	$8,214,427	-$1,364,627	$277,763	Various - Prorated	$13,182,934	-$426,744	$0	$192,923	$0	$0	289,240,400	19
Municipal Waterworks (MW)	$32,342	$34,554	0.0284	$11,674	-$2,080	$352	Various - Prorated	$31,990	-$882	$0	$399	$0	$0	411,071	13
Outdoor Lighting (OL)	$609,028	$626,731	0.0284	$98,913	-$17,794	$5,200	Various - Prorated	$607,902	-$8,638	$0	$3,523	$0	$7	3,482,855	0
Street Lighting (SL)	$99,478	$104,147	0.0284	$18,628	-$3,319	$223	Various - Prorated	$99,259	-$2,209	$0	$636	$0	$0	655,907	53
Total	$45,298,154	$48,809,223		$19,000,846	-$3,285,890	$556,367		$45,041,861	-$1,364,417	$128,054	$561,476	$21,418	-$25	669,043,874	174,164

[1] Total Revenues (a) are being reported on a billed basis only
[2] DSM Revenues (i) are booked directly to Miscellaneous Revenue, therefore are not included in (a) Total Electric Revenues
[3] ECR Factor was prorated daily beginning 8/27/10 through 9/28/10 due to corresponding prorated base rates

KPSC Case No. 2011-00401
KIUC's First Set of Data Requests
Dated January 13, 2012
Item No. 40
Attachment 1
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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

October 2010	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$13,268,562	$13,251,886	0.0284	$4,006,271	-$368,242	$278,200	0.021050	$13,348,708	-$51,514	$226,698	$136,834	$21,396	-$2	141,065,869	142,456
Small General Service (SGS)	$1,267,501	$1,260,764	0.0284	$273,413	-$25,212	$26,140	0.021050	$1,254,466	-$3,507	$563	$9,343	$0	-$26	9,627,206	23,110
Medium General Service (MGS)	$4,275,588	$4,271,218	0.0284	$1,172,549	-$108,188	$87,981	0.021050	$4,204,439	-$15,480	$2,401	$40,049	$0	$6	41,286,943	7,570
Large General Service (LGS)	$5,247,022	$5,259,893	0.0284	$1,675,007	-$154,933	$107,503	0.021050	$5,146,349	-$22,650	$2,809	$57,210	$0	$0	58,979,122	846
Quantity Power (QP)	$4,333,216	$4,379,102	0.0284	$1,868,003	-$173,053	$88,808	0.021050	$4,245,234	-$25,443	$824	$63,802	$0	$0	65,774,740	86
Commercial & Industrial Power - Time of Day (CIPTOD)	$6,019,833	$6,225,311	0.0284	$3,018,386	-$309,440	$111,013	0.021050	$5,908,820	-$77,941	$0	$70,890	$0	$0	106,281,180	19
Municipal Waterworks (MW)	$35,069	$35,166	0.0284	$11,847	-$1,098	$739	0.021050	$34,522	-$137	$25	$405	$0	-$5	417,163	15
Outdoor Lighting (OL)	$631,612	$626,878	0.0284	$115,135	-$10,605	$13,030	0.021050	$628,653	-$1,478	$0	$3,784	$0	$4	4,054,059	0
Street Lighting (SL)	$109,675	$109,183	0.0284	$22,652	-$2,163	$2,236	0.021050	$107,441	-$354	$0	$774	$0	$0	797,596	57
Total	$35,188,077	$35,419,401		$12,163,262	-$1,152,935	$715,649		$34,878,632	-$198,505	$233,321	$383,069	$21,396	-$23	428,283,878	174,159

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

Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

November 2010	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$14,461,097	$14,154,811	0.0284	$4,305,457	-$22,052	$179,431	0.012323	$14,704,506	-$19,511	$243,865	$147,053	$21,417	-$56	151,600,612	142,698
Small General Service (SGS)	$1,260,609	$1,238,764	0.0284	$265,043	-$1,365	$15,369	0.012323	$1,256,066	-$1,210	$546	$9,052	$0	$0	9,332,493	23,209
Medium General Service (MGS)	$4,033,194	$3,957,432	0.0284	$1,064,570	-$4,182	$48,523	0.012323	$4,003,344	-$5,197	$2,196	$36,370	$0	$249	37,484,859	7,579
Large General Service (LGS)	$5,115,818	$5,015,976	0.0284	$1,591,248	-$10,312	$63,051	0.012323	$5,061,399	-$6,989	$2,614	$54,340	$0	-$249	56,029,860	840
Quantity Power (QP)	$4,239,878	$4,150,039	0.0284	$1,893,695	-$13,548	$47,718	0.012323	$4,190,136	-$9,010	$795	$64,679	$0	$0	66,679,410	89
Commerical & Industrial Power - Time of Day (CIPTOD)	$10,526,611	$10,569,703	0.0284	$5,705,060	-$296,230	$170,656	0.012323	$10,355,955	-$51,507	$0	$133,989	$0	$0	200,882,400	18
Municipal Waterworks (MW)	$34,474	$33,517	0.0284	$11,446	$58	$521	0.012323	$43,878	$5	$24	$391	$0	-$18	403,030	15
Outdoor Lighting (OL)	$638,507	$627,784	0.0284	$122,259	-$670	$7,760	0.012323	$636,078	-$652	$0	$4,284	$0	$3	4,304,885	0
Street Lighting (SL)	$116,233	$114,293	0.0284	$25,113	-$238	$1,457	0.012323	$114,778	-$136	$0	$658	$0	$0	884,274	58
Total	$40,426,421	$39,862,320		$14,983,892	-$348,539	$534,484		$40,366,140	-$94,208	$250,039	$451,014	$21,417	-$72	527,601,823	174,506

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

December 2010	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP (k)	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$25,447,693	$24,336,886	0.0284	$7,673,365	-$297,323	$915,616	0.036679	$25,200,311	$209,034	$435,032	$262,083	$21,406	-$22	270,188,922	142,682
Small General Service (SGS)	$1,686,379	$1,617,622	0.0284	$400,410	-$15,514	$59,667	0.036679	$1,640,635	$10,909	$833	$13,676	$0	-$1	14,098,944	23,208
Medium General Service (MGS)	$5,168,479	$4,954,565	0.0284	$1,369,650	-$53,009	$182,851	0.036679	$5,007,913	$37,289	$2,810	$46,781	$0	$0	48,227,110	7,411
Large General Service (LGS)	$6,143,546	$5,883,004	0.0284	$1,918,354	-$73,770	$217,009	0.036679	$5,930,262	$51,781	$3,160	$65,521	$0	$0	67,547,690	875
Quantity Power (QP)	$4,703,615	$4,500,162	0.0284	$1,842,287	-$69,717	$161,579	0.036679	$4,545,750	$48,667	$892	$62,923	$0	$0	64,869,255	82
Commercial & Industrial Power - Time of Day (CIPTOD)	$11,218,753	$10,865,292	0.0284	$6,097,742	-$132,727	$274,113	0.036679	$10,944,640	$68,863	$0	$143,211	$0	$0	214,709,220	17
Municipal Waterworks (MW)	$37,107	$35,520	0.0284	$12,052	-$467	$1,314	0.036679	$35,820	$328	$26	$412	$0	$0	424,368	13
Outdoor Lighting (OL)	$654,183	$628,205	0.0284	$131,901	-$5,137	$23,044	0.036679	$636,484	$3,623	$0	$4,447	$0	$1	4,644,408	0
Street Lighting (SL)	$108,956	$104,535	0.0284	$24,974	-$967	$3,855	0.036679	$105,101	$681	$0	$853	$0	$0	879,352	52
Total	$55,168,711	$52,925,792		$19,470,735	-$648,632	$1,839,068		$54,046,916	$431,176	$442,753	$599,907	$21,406	-$21	685,589,269	174,340

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

January 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP (k)	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$34,190,990	$32,657,235	0.0284	$10,423,072	-$268,499	$1,264,476	0.037735	$33,784,021	$160,293	$590,858	$355,995	$21,534	-$44	367,009,588	143,183
Small General Service (SGS)	$2,044,857	$1,957,909	0.0284	$528,785	-$13,694	$74,384	0.037735	$1,989,110	$8,198	$1,109	$18,060	$0	$0	18,619,194	23,203
Medium General Service (MGS)	$6,367,982	$6,095,371	0.0284	$1,724,350	-$44,775	$231,656	0.037735	$6,176,600	$26,788	$3,553	$58,901	$0	$40	60,716,563	7,587
Large General Service (LGS)	$6,691,968	$6,398,702	0.0284	$2,096,898	-$54,227	$243,390	0.037735	$6,454,048	$32,484	$3,518	$71,620	$0	$0	73,834,437	882
Quantity Power (QP)	$5,227,879	$4,983,875	0.0284	$2,316,421	-$64,935	$189,339	0.037735	$5,039,265	$40,482	$723	$79,117	$0	$0	81,564,117	88
Commercial & Industrial Power - Time of Day (CIPTOD)	$10,406,680	$9,965,873	0.0284	$5,414,460	-$178,336	$373,090	0.037735	$10,033,590	$118,890	$0	$127,164	$0	$0	190,650,000	18
Municipal Waterworks (MW)	$42,226	$40,363	0.0284	$13,707	-$352	$1,537	0.037735	$40,827	$210	$30	$468	$0	$0	482,655	14
Outdoor Lighting (OL)	$654,400	$627,593	0.0284	$129,503	-$3,324	$23,835	0.037735	$635,790	$1,898	$0	$4,396	$0	$2	4,559,953	0
Street Lighting (SL)	$91,531	$87,712	0.0284	$20,581	-$529	$3,328	0.037735	$88,200	$316	$0	$703	$0	$0	724,699	51
Total	$65,718,513	$62,814,634		$22,667,778	-$628,671	$2,405,036		$64,241,451	$389,559	$599,791	$716,423	$21,534	-$1	798,161,206	175,026

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

Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

February 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$27,535,064	$25,803,748	0.0284	$8,158,302	$643,415	$604,774	0.022077	$27,641,511	$183,115	$462,296	$278,636	$21,433	-$57	287,264,168	142,733
Small General Service (SGS)	$1,757,795	$1,662,799	0.0284	$421,249	$33,140	$38,022	0.022077	$1,731,954	$9,448	$884	$14,386	$0	$0	14,832,702	23,076
Medium General Service (MGS)	$5,526,421	$5,211,617	0.0284	$1,445,073	$113,209	$119,851	0.022077	$5,429,350	$32,387	$2,968	$49,357	$0	$0	50,882,862	7,466
Large General Service (LGS)	$6,243,238	$5,854,146	0.0284	$1,892,681	$145,746	$136,462	0.022077	$6,124,894	$42,239	$3,156	$64,645	$0	$0	66,643,686	889
Quantity Power (QP)	$5,607,186	$5,196,562	0.0284	$2,327,191	$149,722	$131,482	0.022077	$5,484,824	$49,935	$1,024	$79,485	$0	$0	81,943,335	91
Commercial & Industrial Power - Time of Day (CIPTOD)	$12,456,044	$11,680,138	0.0284	$6,434,049	$145,891	$359,033	0.022077	$12,850,857	$119,872	$0	$151,110	$0	$0	226,551,020	22
Municipal Waterworks (MW)	$36,102	$33,770	0.0284	$11,450	$903	$780	0.022077	$35,565	$257	$25	$391	$0	$0	403,173	14
Outdoor Lighting (OL)	$654,016	$625,074	0.0284	$108,195	$8,674	$14,110	0.022077	$640,676	$2,497	$0	$3,655	$0	$7	3,809,694	0
Street Lighting (SL)	$87,375	$83,265	0.0284	$16,405	$1,294	$1,887	0.022077	$85,483	$368	$0	$560	$0	$0	577,624	47
Total	$59,903,241	$56,151,120		$20,814,595	$1,241,994	$1,406,403		$60,025,114	$440,118	$470,353	$642,225	$21,434	-$51	732,908,264	174,338

[1] Total Revenues (a) are being reported on a billed basis only
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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

March 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$18,561,137	$19,304,211	0.0284	$6,007,542	-$576,536	-$49,273	-0.002632	$19,159,042	-$343,902	$340,422	$205,185	$21,480	-$28	211,533,175	142,865
Small General Service (SGS)	$1,391,331	$1,433,923	0.0284	$335,443	-$31,741	-$3,359	-0.002632	$1,404,396	-$18,948	$700	$11,455	$0	$1	11,811,361	23,140
Medium General Service (MGS)	$4,373,657	$4,529,285	0.0284	$1,231,580	-$116,877	-$10,850	-0.002632	$4,390,689	-$69,966	$2,528	$42,064	$0	$0	43,365,506	7,591
Large General Service (LGS)	$5,276,954	$5,492,660	0.0284	$1,758,270	-$164,983	-$11,875	-0.002632	$5,307,547	-$98,902	$2,863	$60,054	$0	$0	61,910,907	902
Quantity Power (QP)	$4,476,216	$4,706,648	0.0284	$2,064,047	-$182,733	-$6,998	-0.002632	$4,489,246	-$111,198	$823	$70,497	$0	$0	72,677,694	88
Commercial & Industrial Power - Time of Day (CIPTOD)	$9,958,197	$9,960,488	0.0284	$5,274,557	-$96,574	$85,703	-0.002632	$9,872,495	-$115,299	$0	$123,878	$0	$0	185,723,840	18
Municipal Waterworks (MW)	$31,524	$32,940	0.0284	$11,172	-$1,074	-$83	-0.002632	$31,702	-$641	$24	$382	$0	$0	393,367	13
Outdoor Lighting (OL)	$612,042	$626,738	0.0284	$108,519	-$10,510	-$1,657	-0.002632	$625,198	-$6,197	$0	$3,666	$0	$3	3,821,086	0
Street Lighting (SL)	$120,800	$123,900	0.0284	$24,491	-$2,289	-$273	-0.002632	$121,073	-$1,375	$0	$837	$0	$0	862,365	56
Total	$44,801,857	$46,210,794		$16,815,620	-$1,183,317	$1,335		$45,401,388	-$766,427	$347,360	$518,018	$21,480	-$25	592,099,301	174,673

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

April 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$16,448,394	$16,068,115	0.0284	$4,938,468	-$64,252	$557,913	0.034499	$16,322,181	-$303,444	$279,689	$168,674	$21,389	-$1	173,889,713	142,171
Small General Service (SGS)	$1,349,566	$1,316,304	0.0284	$292,525	-$3,797	$45,040	0.034499	$1,314,741	-$17,973	$604	$9,992	$0	$0	10,300,167	23,088
Medium General Service (MGS)	$4,293,645	$4,196,202	0.0284	$1,134,170	-$14,832	$143,279	0.034499	$4,174,163	-$69,741	$2,313	$38,738	$0	$0	39,935,573	7,532
Large General Service (LGS)	$5,335,533	$5,225,967	0.0284	$1,667,910	-$22,288	$177,487	0.034499	$5,162,473	-$102,600	$2,723	$56,967	$0	$0	58,729,226	887
Quantity Power (QP)	$4,596,894	$4,529,762	0.0284	$1,956,283	-$29,647	$149,992	0.034499	$4,447,683	-$120,029	$776	$66,817	$0	$0	68,883,220	85
Commercial & Industrial Power - Time of Day (CIPTOD)	$9,577,581	$9,906,474	0.0284	$5,468,016	-$298,520	$165,990	0.034499	$9,411,591	-$324,784	$0	$128,421	$0	$0	192,535,760	17
Municipal Waterworks (MW)	$32,623	$31,971	0.0284	$10,835	-$141	$1,089	0.034499	$31,557	-$666	$24	$370	$0	$0	381,514	13
Outdoor Lighting (OL)	$643,378	$625,639	0.0284	$92,004	-$1,153	$21,442	0.034499	$630,598	-$5,554	$0	$3,003	$0	$1	3,239,591	0
Street Lighting (SL)	$141,605	$135,853	0.0284	$24,417	$368	$5,194	0.034499	$136,409	-$644	$0	$834	$0	$0	859,746	80
Total	$42,419,218	$42,036,287		$15,584,628	-$434,264	$1,267,425		$41,631,396	-$945,434	$286,129	$473,816	$21,389	$0	548,754,510	173,873

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

May 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$13,260,787	$12,712,589	0.0284	$3,829,082	$29,704	$437,851	0.033578	$13,173,127	-$71,494	$215,252	$130,785	$21,334	$23	134,826,840	141,677
Small General Service (SGS)	$1,277,071	$1,229,432	0.0284	$262,280	$2,050	$41,518	0.033578	$1,243,352	-$4,886	$540	$8,957	$0	$0	9,235,195	23,141
Medium General Service (MGS)	$4,144,015	$3,984,136	0.0284	$1,082,674	$8,418	$134,697	0.033578	$4,025,896	-$20,215	$2,220	$36,979	$0	$0	38,122,341	7,530
Large General Service (LGS)	$5,530,190	$5,311,304	0.0284	$1,700,884	$13,096	$179,727	0.033578	$5,352,094	-$32,030	$2,773	$58,094	$0	$0	59,890,278	890
Quantity Power (QP)	$4,893,437	$4,690,680	0.0284	$2,041,155	$14,621	$159,109	0.033578	$4,735,184	-$40,688	$854	$69,716	$0	$0	71,871,670	89
Commerical & Industrial Power - Time of Day (CIPTOD)	$10,839,092	$10,663,493	0.0284	$5,815,099	-$50,558	$329,859	0.033578	$10,557,720	-$240,275	$0	$136,573	$0	$0	204,757,003	19
Municipal Waterworks (MW)	$35,991	$34,549	0.0284	$11,682	$91	$1,170	0.033578	$34,846	-$218	$26	$399	$0	$0	411,338	13
Outdoor Lighting (OL)	$646,694	$623,787	0.0284	$81,553	$683	$20,881	0.033578	$631,659	-$1,510	$0	$2,849	$0	$5	2,871,586	0
Street Lighting (SL)	$110,022	$106,080	0.0284	$15,796	$123	$3,574	0.033578	$106,448	-$295	$0	$540	$0	$0	556,207	54
Total	$40,737,298	$39,356,050		$14,840,206	$18,229	$1,308,387		$39,860,326	-$411,612	$221,665	$444,890	$21,334	$28	522,542,458	173,413

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

June 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$16,307,233	$14,837,682	0.0284	$4,532,910	$395,652	$908,139	0.058242	$15,750,148	-$10,332	$195,171	$154,822	$21,260	$2	159,609,491	141,461
Small General Service (SGS)	$1,427,695	$1,314,069	0.0284	$292,143	$25,541	$78,754	0.058242	$1,360,667	-$646	$2,845	$9,977	$0	$0	10,286,740	23,178
Medium General Service (MGS)	$4,801,946	$4,392,500	0.0284	$1,211,862	$105,844	$264,946	0.058242	$4,557,682	-$2,736	$11,429	$41,391	$0	$0	42,671,196	7,513
Large General Service (LGS)	$6,048,199	$5,505,157	0.0284	$1,764,253	$153,687	$333,175	0.058242	$5,726,955	-$4,078	$12,871	$60,258	$0	$0	62,121,595	894
Quantity Power (QP)	$5,016,477	$4,505,137	0.0284	$1,963,278	$171,685	$277,001	0.058242	$4,744,401	-$4,402	$4,922	$67,056	$0	$0	69,129,490	86
Commerical & Industrial Power - Time of Day (CIPTOD)	$11,843,163	$10,866,510	0.0284	$5,955,642	$327,709	$563,331	0.058242	$11,231,348	-$54,281	$0	$139,895	$0	$0	209,705,687	19
Municipal Waterworks (MW)	$34,845	$31,648	0.0284	$10,695	$934	$1,922	0.058242	$32,998	-$24	$74	$365	$0	$0	376,576	13
Outdoor Lighting (OL)	$669,160	$623,545	0.0284	$73,252	$6,299	$36,853	0.058242	$633,961	-$74	$0	$2,535	$0	$2	2,579,303	0
Street Lighting (SL)	$117,254	$109,138	0.0284	$14,676	$1,253	$6,407	0.058242	$110,846	-$45	$0	$501	$0	$0	516,755	57
Total	$46,265,971	$42,185,385		$15,818,710	$1,188,605	$2,470,526		$44,149,006	-$76,618	$227,312	$476,801	$21,260	$4	556,996,833	173,221

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

July 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP (k)	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$17,377,111	$16,445,498	0.0284	$5,064,670	-$35,526	$652,015	0.038659	$17,021,317	$120,900	$133,507	$172,983	$21,240	$1	178,333,439	141,397
Small General Service (SGS)	$1,464,479	$1,393,378	0.0284	$320,473	-$2,239	$54,736	0.038659	$1,429,505	$7,660	$6,045	$10,945	$0	$0	11,284,256	23,140
Medium General Service (MGS)	$4,924,574	$4,673,524	0.0284	$1,308,797	-$9,145	$184,248	0.038659	$4,779,059	$31,245	$24,370	$44,702	$0	$0	46,084,410	7,514
Large General Service (LGS)	$5,858,760	$5,546,776	0.0284	$1,782,703	-$11,096	$220,005	0.038659	$5,698,915	$42,186	$27,089	$60,888	$0	$0	62,771,232	891
Quantity Power (QP)	$4,668,268	$4,398,400	0.0284	$1,878,255	-$13,227	$174,071	0.038659	$4,511,812	$44,873	$8,530	$64,152	$0	$0	66,135,735	84
Commercial & Industrial Power - Time of Day (CIPTOD)	$10,590,062	$9,714,683	0.0284	$5,303,954	$209,005	$483,380	0.038659	$10,106,681	$58,426	$0	$124,568	$0	$0	186,758,940	16
Municipal Waterworks (MW)	$35,939	$34,006	0.0284	$11,507	-$81	$1,346	0.038659	$34,818	$275	$225	$393	$0	$0	405,186	13
Outdoor Lighting (OL)	$651,308	$623,189	0.0284	$78,276	-$650	$24,336	0.038659	$631,573	$1,834	$0	$2,599	$0	$1	2,756,210	0
Street Lighting (SL)	$106,018	$101,299	0.0284	$14,389	-$92	$3,968	0.038659	$102,050	$352	$0	$491	$0	$0	506,668	55
Total	$45,676,518	$42,930,753		$15,763,025	$136,948	$1,798,105		$44,315,730	$307,750	$199,766	$481,722	$21,240	$2	555,036,076	173,110

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

August 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP (k)	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$19,188,609	$18,552,232	0.0284	$5,760,895	$309,828	$550,419	0.029277	$19,006,151	-$441,881	$151,351	$196,761	$21,267	-$37	202,848,405	141,530
Small General Service (SGS)	$1,495,822	$1,449,263	0.0284	$340,947	$18,376	$42,738	0.029277	$1,472,456	-$26,199	$6,463	$11,644	$0	$0	12,005,160	23,269
Medium General Service (MGS)	$5,067,997	$4,907,426	0.0284	$1,378,722	$74,188	$145,025	0.029277	$4,959,546	-$105,732	$25,868	$47,090	$0	$0	48,546,559	7,533
Large General Service (LGS)	$6,062,365	$5,866,547	0.0284	$1,886,052	$100,546	$173,597	0.029277	$5,930,631	-$142,743	$28,887	$64,418	$0	$0	66,410,285	895
Quantity Power (QP)	$4,583,678	$4,429,667	0.0284	$1,904,716	$100,627	$131,340	0.029277	$4,482,350	-$143,011	$8,523	$65,055	$0	$0	67,067,460	86
Commerical & Industrial Power - Time of Day (CIPTOD)	$16,102,714	$15,468,984	0.0284	$8,389,622	$265,320	$507,204	0.029277	$15,595,511	-$335,825	$0	$197,031	$0	$0	295,409,226	21
Municipal Waterworks (MW)	$35,153	$34,019	0.0284	$11,481	$620	$1,006	0.029277	$34,372	-$884	$226	$392	$0	$0	404,248	13
Outdoor Lighting (OL)	$640,707	$621,602	0.0284	$88,609	$4,743	$18,292	0.029277	$629,191	-$6,875	$0	$2,947	$0	$3	3,120,051	0
Street Lighting (SL)	$103,665	$100,534	0.0284	$16,222	$874	$2,949	0.029277	$100,715	-$1,246	$0	$554	$0	$0	571,213	53
Total	$53,280,709	$51,430,274		$19,777,266	$875,121	$1,572,569		$52,210,923	-$1,204,397	$221,318	$585,893	$21,267	-$34	696,382,607	173,400

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

												Other Revenue			
September 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Residential HEAP	Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$15,849,059	$15,447,745	0.0284	$4,734,711	$836,539	$52,428	0.003272	$16,068,322	-$670,613	$124,642	$161,716	$21,246	$8	166,715,170	141,285
Small General Service (SGS)	$1,399,554	$1,373,359	0.0284	$311,941	$55,156	$4,587	0.003272	$1,412,409	-$44,201	$5,900	$10,654	$0	$0	10,983,836	23,278
Medium General Service (MGS)	$4,648,342	$4,545,262	0.0284	$1,268,806	$224,720	$15,011	0.003272	$4,672,924	-$180,012	$23,762	$43,336	$0	$23	44,676,265	7,497
Large General Service (LGS)	$5,863,155	$5,717,421	0.0284	$1,829,461	$324,072	$18,924	0.003272	$5,882,252	-$259,746	$28,548	$62,485	$0	$0	64,417,624	889
Quantity Power (QP)	$4,936,298	$4,780,286	0.0284	$2,006,889	$346,707	$20,889	0.003272	$4,923,894	-$280,129	$8,486	$68,545	$0	$0	70,665,090	91
Commercial & Industrial Power - Time of Day (CIPTOD)	$9,776,454	$9,444,970	0.0284	$5,117,126	$904,491	$31,884	0.003272	$9,744,572	-$725,070	$0	$120,178	$0	$0	180,180,480	14
Municipal Waterworks (MW)	$44,082	$42,913	0.0284	$14,535	$1,856	$427	0.003272	$43,948	-$1,586	$233	$496	$0	-$23	511,811	14
Outdoor Lighting (OL)	$632,699	$623,614	0.0284	$98,530	$17,585	$2,040	0.003272	$632,996	-$14,048	$0	$3,508	$0	$0	3,469,351	0
Street Lighting (SL)	$114,843	$112,752	0.0284	$19,901	$3,167	$805	0.003272	$114,037	-$2,561	$0	$680	$0	$0	700,725	54
Total	$43,264,487	$42,088,323		$15,401,898	$2,714,293	$146,995		$43,495,354	-$2,177,966	$191,571	$471,599	$21,246	$8	542,320,352	173,122

[1] Total Revenues (a) are being reported on a billed basis only
[2] DSM Revenues (i) are booked directly to Miscellaneous Revenue, therefore are not included in (a) Total Electric Revenues

Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

October 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$12,332,413	$12,099,667	0.0284	$3,628,571	$146,904	-$22,238	-0.001794	$12,576,530	-$37,059	$96,549	$123,934	$21,210	$1	127,766,599	141,179
Small General Service (SGS)	$1,234,007	$1,219,602	0.0284	$258,103	$10,434	-$2,227	-0.001794	$1,254,123	-$2,619	$4,853	$8,817	$0	$0	9,088,127	23,307
Medium General Service (MGS)	$3,996,894	$3,934,902	0.0284	$1,073,643	$43,455	-$7,155	-0.001794	$4,038,763	-$10,978	$19,975	$36,671	$0	$0	37,804,317	7,479
Large General Service (LGS)	$5,295,537	$5,199,073	0.0284	$1,642,752	$67,608	-$9,401	-0.001794	$5,328,680	-$18,051	$25,023	$56,108	$0	$0	57,843,384	892
Quantity Power (QP)	$4,517,757	$4,406,414	0.0284	$1,852,152	$76,327	-$8,011	-0.001794	$4,552,870	-$20,233	$7,420	$63,260	$0	$0	65,216,615	86
Commerical & Industrial Power - Time of Day (CIPTOD)	$6,645,464	$6,480,682	0.0284	$3,170,554	$178,641	-$7,416	-0.001794	$6,652,880	-$80,916	$0	$74,472	$0	$0	111,639,220	20
Municipal Waterworks (MW)	$35,621	$34,926	0.0284	$11,795	$478	-$64	-0.001794	$35,917	-$121	$232	$403	$0	$0	415,327	14
Outdoor Lighting (OL)	$629,560	$623,504	0.0284	$114,517	$4,664	-$1,248	-0.001794	$633,141	-$1,125	$0	$3,764	$0	$1	4,032,299	0
Street Lighting (SL)	$126,997	$125,297	0.0284	$25,652	$1,294	$76	-0.001794	$126,924	-$546	$0	$876	$0	$0	903,230	68
Total	$34,814,249	$34,124,067		$11,777,739	$530,004	-$57,685		$35,199,828	-$171,649	$154,052	$368,305	$21,210	$2	414,709,118	173,045

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

November 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Other Revenue: Residential HEAP	Other Revenue: Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$15,291,468	$14,507,518	0.0284	$4,425,252	$367,706	$79,351	0.005174	$15,518,565	$164,537	$119,658	$151,142	$21,213	$0	155,818,740	141,319
Small General Service (SGS)	$1,312,489	$1,263,486	0.0284	$273,451	$22,727	$6,787	0.005174	$1,323,244	$10,151	$5,139	$9,338	$0	$0	9,628,551	23,327
Medium General Service (MGS)	$4,035,505	$3,854,302	0.0284	$1,037,682	$86,257	$20,865	0.005174	$4,053,322	$38,639	$19,180	$35,442	$0	$0	36,538,082	7,451
Large General Service (LGS)	$5,258,200	$4,987,631	0.0284	$1,579,152	$131,005	$27,116	0.005174	$5,255,925	$58,511	$23,660	$53,936	$0	$0	55,603,937	893
Quantity Power (QP)	$5,067,780	$4,732,408	0.0284	$2,037,329	$167,142	$25,243	0.005174	$5,049,818	$73,402	$7,280	$69,585	$0	$0	71,736,945	90
Commerical & Industrial Power - Time of Day (CIPTOD)	$15,383,993	$14,395,105	0.0284	$8,113,911	$566,929	$49,012	0.005174	$15,334,983	$182,374	$0	$190,572	$0	$0	285,701,080	18
Municipal Waterworks (MW)	$36,178	$34,202	0.0284	$11,577	$962	$187	0.005174	$36,319	$431	$227	$395	$0	$0	407,648	14
Outdoor Lighting (OL)	$645,761	$623,585	0.0284	$121,413	$10,115	$3,357	0.005174	$640,410	$4,450	$0	$4,253	$0	$0	4,275,089	0
Street Lighting (SL)	$113,164	$108,864	0.0284	$24,068	$2,000	$582	0.005174	$112,586	$896	$0	$822	$0	$0	847,465	56
Total	$47,144,538	$44,507,102		$17,623,834	$1,354,843	$212,503		$47,325,172	$533,391	$175,144	$515,486	$21,213	$0	620,557,537	173,168

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Kentucky Power Company
Revenue by Retail Rate Schedule
By Month for the Period July 2010 through December 2011

												Other Revenue			
December 2011	Total Revenues[1] (a)	Base Rate Revenues (b)	Base Fuel Rate	Fuel Revenue in Base (c)	Fuel Adjustment Revenue (d)	ECR Revenue (e)	ECR Factor (f)	Revenue Subject to ECR Factor (g)	System Sales Revenue (h)	DSM Revenue[2] (i)	Capacity Charge Revenue (j)	Residential HEAP	Net Merger Savings Credit (k)	kWh Sales (l)	Number of Customers (m)
Residential Service (RS)	$20,840,700	$19,715,432	0.0284	$6,147,311	$339,857	$216,505	0.010410	$20,988,982	$337,700	$166,606	$209,960	$21,249	$0	216,454,628	141,499
Small General Service (SGS)	$1,556,890	$1,489,856	0.0284	$352,829	$19,497	$16,121	0.010410	$1,558,179	$19,365	$6,642	$12,050	$0	$0	12,423,543	23,318
Medium General Service (MGS)	$4,760,085	$4,531,181	0.0284	$1,244,083	$68,776	$49,278	0.010410	$4,747,774	$68,359	$22,939	$42,492	$0	$0	43,805,727	7,438
Large General Service (LGS)	$5,872,642	$5,554,169	0.0284	$1,785,337	$98,945	$60,609	0.010410	$5,841,961	$97,941	$26,979	$60,978	$0	$0	62,863,994	898
Quantity Power (QP)	$5,058,788	$4,704,129	0.0284	$2,094,897	$116,660	$51,832	0.010410	$5,012,827	$114,595	$5,874	$71,551	$0	$0	73,763,970	88
Commercial & Industrial Power - Time of Day (CIPTOD)	$11,597,379	$10,689,218	0.0284	$5,900,758	$326,504	$118,979	0.010410	$11,478,399	$324,082	$0	$138,596	$0	$0	207,773,160	19
Municipal Waterworks (MW)	$38,442	$36,266	0.0284	$12,307	$680	$399	0.010410	$38,284	$676	$242	$420	$0	$0	433,354	13
Outdoor Lighting (OL)	$646,574	$621,113	0.0284	$130,308	$7,224	$6,619	0.010410	$638,676	$7,241	$0	$4,394	$0	$9	4,588,313	0
Street Lighting (SL)	$113,389	$108,479	0.0284	$25,912	$1,432	$1,168	0.010410	$112,221	$1,424	$0	$865	$0	$0	912,396	56
Total	$50,484,888	$47,449,844		$17,693,742	$979,597	$521,509		$50,417,303	$971,382	$229,282	$541,327	$21,249	$9	623,019,085	173,329

[1] Total Revenues (a) are being reported on a billed basis only
[2] DSM Revenues (i) are booked directly to Miscellaneous Revenue, therefore are not included in (a) Total Electric Revenues

Kentucky Power Company

REQUEST

Please provide the monthly ECR filings for the period January 2010 through the present.

RESPONSE

Please see enclosed CD for copies of the monthly ECR filings from January 2010 to the present, which includes November 2011.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please provide, by month, the amount of the Tariff E.S. Base Period Revenue Requirement, BRR by retail rate schedule. Also include any amounts allocated to non-retail sales.

RESPONSE

The BRR is only developed on a total company basis, not per retail rate schedule. Please see the attachment to this response for the monthly total company BRR.

WITNESS: Lila P Munsey

KENTUCKY POWER COMPANY

Original Sheet No. 29-1
Canceling _______ Sheet No. 29-1

P.S.C. ELECTRIC NO. 9

TARIFF E.S.
(Environmental Surcharge)

APPLICABLE. (T)

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

RATE.

1. The environmental surcharge shall provide for monthly adjustments based on a percent of revenues, equal to the difference between the environmental compliance costs in the base period as provided in Paragraph 3 below and in the current period according to the following formula:

$$\text{Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m)}}{\text{KY Retail R(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non-Physical Revenues.)

KY Retail R(m) = Kentucky Retail Revenues for the Expense Month.

2. Monthly Environmental Surcharge Gross Revenue Requirement, E(m)

$$E(m) = CRR - BRR$$

Where:

CRR = Current Period Revenue Requirement for the Expense Month.

BRR = Base Period Revenue Requirement.

3. Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs	
JANUARY	$ 3,991,163	(I)
FEBRUARY	3,590,810	
MARCH	3,651,374	
APRIL	3,647,040	
MAY	3,922,590	
JUNE	3,627,274	
JULY	3,805,325	
AUGUST	4,088,830	
SEPTEMBER	3,740,010	
OCTOBER	3,260,302	
NOVEMBER	2,786,040	
DECEMBER	4,074,321	(I)
	$44,185,079	

(Continued on Sheet 29-2)

DATE OF ISSUE July 16, 2010 DATE EFFECTIVE Service rendered on and

ISSUED BY E.K. WAGNER DIRECTOR OF REGULATORY SERVICES FRANKFORT, KENTUCKY
NAME TITLE ADDRESS

Issued by authority of an Order of the Public Service Commission in Case No. 2009-00459 dated June 28, 2010

KENTUCKY
PUBLIC SERVICE COMMISSION
JEFF R. DEROUEN
EXECUTIVE DIRECTOR
TARIFF BRANCH
Brent Kirtley
EFFECTIVE
6/29/2010
PURSUANT TO 807 KAR 5:011 SECTION 9 (1)

Kentucky Power Company

REQUEST

Please provide, in excel spreadsheet format with formulas, a "compliance" proof of revenues with detail for each rate schedule reflecting the Commission approved rates from Case No. 2009-000459.

RESPONSE

A proof of revenues by rate schedule is attached, reflecting the approved rates from Case No. 2009-00459. Please see enclosed CD for the excel file with formulas intact and unprotected.

WITNESS: Lila P Munsey

KENTUCKY POWER BILLING ANALYSIS
TEST YEAR ENDED SEPTEMBER 30, 2009
PROFORMA SUMMARY - SETTLEMENT

Tariff	Total Current Revenue	Total Proposed Revenue	Difference	% Difference
RS Total	$196,608,757	$229,819,967	$33,211,211	16.89%
RSLMTOD Total	$355,760	$420,374	$64,614	18.16%
RSTOD Total	$0	$0	$0	0.00%
OL Total	$6,588,349	$7,697,959	$1,109,610	16.84%
SGS Metered Total	$14,121,390	$16,506,476	$2,385,087	16.89%
SGSLMTOD (225)	$186	$181	($5)	-2.45%
SGS NM Total	$430,343	$496,150	$65,807	15.29%
MGS RL (214)	$157,811	$177,190	$19,379	12.28%
MGS Sec Total	$48,604,041	$56,760,186	$8,156,145	16.78%
MGSLMTOD (223)	$99,614	$117,867	$18,253	18.32%
MGSTOD (229)	$370,990	$434,087	$63,097	17.01%
MGS Pri Total	$1,796,231	$2,111,682	$315,451	17.56%
MGS Sub (236)	$611,891	$719,646	$107,755	17.61%
LGS Sec Total	$45,344,899	$53,718,205	$8,373,306	18.47%
LGSLMTOD (251)	$231,572	$274,543	$42,971	18.56%
LGS Pri Total	$8,122,063	$9,137,011	$1,014,949	12.50%
LGS Sub (248)	$5,296,907	$5,650,641	$353,734	6.68%
QP Sec (356)	$310,222	$347,771	$37,549	12.10%
QP Pri (358)	$26,464,795	$29,130,258	$2,665,463	10.07%
QP Sub (359)	$25,813,058	$26,605,693	$792,634	3.07%
QP Tran (360)	$2,388,032	$2,513,419	$125,387	5.25%
CIP Sub (371)	$103,958,339	$107,477,290	$3,518,951	3.38%
CIP Tran (372)	$20,377,867	$21,355,266	$977,399	4.80%
SL (528)	$1,129,448	$1,319,830	$190,382	16.86%
MW (540)	$582,698	$680,839	$98,141	16.84%
Total	$509,765,263	$573,472,533	$63,707,270	12.50%

KENTUCKY POWER BILLING ANALYSIS
TEST YEAR ENDED SEPTEMBER 30, 2009
REVENUE SUMMARY SHEET - SETTLEMENT

Tariff	Total Per Books Revenue	Revenue Without Green Power	Revenue Without System Sales	Revenue Without Capacity Charge	Revenue Without Net Merger Savings	Revenue With Annualized Fuel	Year End Migration Revenue	Year End Customer Revenue	Proposed Revenue Increase	Proposed Revenue	Verification Difference	Rate Design Proposed Revenue
RS Total	$200,432,953	$200,432,519	$199,732,291	$197,707,556	$199,501,314	$195,692,277	$197,351,853	$196,608,757				$229,819,967
RSLMTOD Total	$368,499	$368,499	$366,941	$362,596	$366,445	$358,903	$359,588	$355,760				$420,374
RS TOD Total	$4,279	$4,279	$4,270	$4,226	$4,265	$4,146	$4,146	$0				$0
Residential Total	$200,805,730	$200,805,296	$200,103,502	$198,074,377	$199,872,024	$196,055,325	$197,715,586	$196,964,517	$33,171,258	$230,135,775	($104,566)	$230,240,341
OL Total	$6,633,250	$6,633,250	$6,639,119	$6,603,257	$6,635,028	$6,546,076	$6,546,076	$6,588,349	$1,109,560	$7,697,909	($50)	$7,697,959
SGS Metered Total	$14,363,605	$14,363,605	$14,324,271	$14,212,988	$14,311,576	$14,105,951	$14,068,805	$14,121,390				$16,506,476
SGSLMTOD (225)	$186	$186	$186	$186	$186	$186	$186	$186				$181
SGS NM Total	$446,529	$446,529	$446,315	$443,630	$446,008	$438,216	$438,216	$430,343				$496,150
SGS Total	$14,810,320	$14,810,320	$14,770,772	$14,656,804	$14,757,770	$14,544,353	$14,507,207	$14,551,918	$2,450,723	$17,002,641	($166)	$17,002,807
MGS RL (214)	$158,794	$158,794	$158,578	$157,120	$158,411	$155,664	$156,766	$157,811				$177,190
MGS Sec	$49,675,601	$49,675,601	$49,521,675	$49,074,799	$49,470,697	$48,658,233	$48,703,993	$48,604,041				$56,760,186
MGSLMTOD (223)	$104,035	$104,035	$103,704	$102,551	$103,572	$101,592	$101,530	$99,614				$117,867
MGSTOD (229)	$263,174	$263,174	$260,993	$258,372	$260,694	$256,364	$370,990	$370,990				$434,087
MGS Pri Total	$1,168,737	$1,168,737	$1,171,061	$1,159,520	$1,169,744	$1,136,638	$1,872,066	$1,796,231				$2,111,682
MGS Sub (236)	$184,561	$184,561	$184,880	$183,224	$184,691	$179,326	$684,112	$611,891				$719,646
MGS Total	$51,554,902	$51,554,902	$51,400,890	$50,935,585	$51,347,809	$50,487,816	$51,889,457	$51,640,579	$8,679,494	$60,320,073	($586)	$60,320,659
LGS Sec Total	$46,464,018	$46,464,018	$46,352,510	$45,876,244	$46,298,179	$45,414,973	$45,381,739	$45,344,899				$53,718,205
LGSLMTOD (251)	$238,014	$238,014	$237,231	$234,692	$236,941	$231,572	$231,572	$231,572				$274,543
LGS Pri Total	$9,100,759	$9,100,759	$9,091,947	$8,999,000	$9,081,344	$8,884,088	$8,245,224	$8,122,063				$9,137,011
LGS Sub (248)	$4,316,513	$4,316,513	$4,313,667	$4,262,919	$4,307,878	$4,210,012	$3,919,669	$5,296,907				$5,650,641
LGS Total	$60,119,303	$60,119,303	$59,995,355	$59,372,855	$59,924,341	$58,740,644	$57,778,205	$58,995,441	$9,784,791	$68,780,232	($169)	$68,780,401
QP Sec (356)	$319,594	$319,594	$318,249	$313,960	$317,760	$310,222	$310,222	$310,222				$347,771
QP Pri (357,358)	$25,523,964	$25,523,964	$25,469,121	$25,151,476	$25,432,885	$24,851,095	$24,977,993	$26,464,795				$29,130,258
QP Sub (359)	$30,379,151	$30,379,151	$30,338,738	$29,931,804	$30,292,316	$29,513,562	$28,226,652	$25,813,058				$26,605,693
QP Tran (360)	$2,462,343	$2,462,343	$2,459,403	$2,426,930	$2,455,699	$2,388,032	$2,388,032	$2,388,032				$2,513,419
QP Total	$58,685,053	$58,685,053	$58,585,511	$57,824,170	$58,498,659	$57,062,910	$55,902,899	$54,976,107	$3,619,503	$58,595,610	($1,531)	$58,597,141
CIP Sub (371)	$103,477,675	$103,477,675	$103,127,321	$102,172,788	$103,544,460	$100,813,395	$101,632,803	$103,958,339				$107,477,290
CIP Tran (372)	$20,126,054	$20,126,054	$20,104,641	$19,919,188	$20,185,685	$19,551,563	$19,551,563	$20,377,867				$21,355,266
CIP Total	$123,603,729	$123,603,729	$123,231,962	$122,091,975	$123,730,145	$120,364,958	$121,184,366	$124,336,206	$4,496,324	$128,832,530	($26)	$128,832,556
SL (528)	$1,148,641	$1,148,641	$1,148,711	$1,141,692	$1,147,910	$1,133,734	$1,133,734	$1,129,448	$190,213	$1,319,661	($169)	$1,319,830
MW (540)	$596,883	$596,883	$594,803	$588,358	$594,068	$582,698	$582,698	$582,698	$98,134	$680,832	($7)	$680,839
Total	$517,957,811	$517,957,377	$516,470,623	$511,289,075	$516,507,755	$505,518,515	$507,240,229	$509,765,263	$63,600,000	$573,365,263	($107,270)	$573,472,533

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

RESIDENTIAL SERVICE (011, 012, 013, 014, 015, 017, 022, 054)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
All kWh	2,447,495,152	$0.07191	$175,999,376	2,447,495,152	$0.08590	$210,239,834
Storage Water Heating	444,814	$0.03853	$17,139	444,814	$0.04940	$21,974
Metered kWh	2,447,939,966			2,447,939,966		
Customer Charge *	1,709,677	$5.96	$10,189,675	1,709,677	$8.15	$13,933,868
Number of Customers	1,716,864			1,716,864		
Employee Discount			($43,303)			($59,120)
Fuel		$0.0023217	$5,683,412		$0.0023217	$5,683,412
Environmental Surcharge			$4,762,458			$0
Total			$196,608,757			$229,819,967

* Includes current HEAP charge of 10¢ and proposed HEAP charge of 15¢ per meter.

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

RESIDENTIAL LOAD MANAGEMENT TIME-OF-DAY SERVICE (028, 030, 032, 034)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	1,546,831	$0.11366	$175,813	1,546,831	$0.13227	$204,599
Off-peak kWh	3,680,077	$0.03853	$141,793	3,680,077	$0.04940	$181,796
Metered kWh	5,226,908			5,226,908		
C&LM Credit	0	($0.00745)	$0	0	($0.00745)	$0
Customer Charge *	2,202	$8.46	$18,629	2,202	$10.70	$23,561
Separate Meter Charge *	24	$3.10	$74	24	$3.15	$76
Number of Customers	2,232			2,232		
Employee Discount			($1,419)			($1,794)
Fuel		$0.0023217	$12,135		$0.0023217	$12,135
Environmental Surcharge			$8,734			$0
Total			$355,760			$420,374

* Includes current HEAP charge of 10¢ and proposed HEAP charge of 15¢ per meter.

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

RESIDENTIAL TIME-OF-DAY SERVICE (036)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	0	$0.11366	$0	0	$0.13227	$0
Off-peak kWh	0	$0.03853	$0	0	$0.04940	$0
Metered kWh	0			0		
Customer Charge *	0	$8.46	$0	0	$10.70	$0
Number of Customers	0			0		
Employee Discount			$0			$0
Fuel		$0.0023217	$0		$0.0023217	$0
Environmental Surcharge			$0			$0
Total			$0			$0

* Includes current HEAP charge of 10¢ and proposed HEAP charge of 15¢ per meter.

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

OUTDOOR LIGHTING (093, 094, 095, 097, 098, 099, 107, 109, 110, 111, 113, 116, 122, 131)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Overhead Lighting Service						
High Pressure Sodium						
100 watts, 9,500 Lumens (094)	297,084	$7.18	$2,133,063	297,084	$8.75	$2,599,485
150 watts, 16,000 Lumens (113)	243,900	$8.20	$1,999,980	243,900	$9.90	$2,414,610
200 watts, 22,000 Lumens (097)	27,504	$10.05	$276,415	27,504	$12.20	$335,549
400 watts, 50,000 Lumens (098)	2,676	$16.33	$43,699	2,676	$19.15	$51,245
Mercury Vapor						
175 watts, 7,000 Lumens (093)	19,980	$7.81	$156,044	19,980	$9.75	$194,805
400 watts, 20,000 Lumens (095)	1,548	$13.48	$20,867	1,548	$16.85	$26,084
Post Top Lighting Service						
High Pressure Sodium						
100 watts, 9,500 Lumens (111)	9,996	$10.53	$105,258	9,996	$13.10	$130,948
150 watts, 16,000 Lumens (122)	828	$17.15	$14,200	828	$21.45	$17,761
Mercury Vapor						
175 watts, 7,000 Lumens (099)	132	$8.96	$1,183	132	$11.20	$1,478
Flood Lighting Service						
High Pressure Sodium						
200 watts, 22,000 Lumens (107)	21,972	$11.30	$248,284	21,972	$13.60	$298,819
400 watts, 50,000 Lumens (109)	51,576	$16.08	$829,342	51,576	$18.85	$972,208
Metal Halide						
250 watts, 20,500 Lumens (110)	1,512	$17.34	$26,218	1,512	$18.20	$27,518
400 watts, 36,000 Lumens (116)	9,852	$22.93	$225,906	9,852	$24.10	$237,433
1000 watts, 110,000 Lumens (131)	936	$49.70	$46,519	936	$52.20	$48,859
Metered kWh	43,815,427			43,815,427		
Facilities Charge						
Pole	51,804	$2.30	$119,149	51,804	$2.85	$147,641
Span	54,696	$1.30	$71,105	54,696	$1.60	$87,514
Lateral	684	$5.35	$3,659	684	$6.25	$4,275
Fuel		$0.0023217	$101,727		$0.0023217	$101,727
Environmental Surcharge			$165,731			$0
Total			$6,588,349			$7,697,959

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

SMALL GENERAL SERVICE (211, 212)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 500 kWh	60,515,315	$0.10013	$6,059,398	60,515,315	$0.13160	$7,963,815
Over 500 kWh	74,089,503	$0.05994	$4,440,925	74,089,503	$0.07116	$5,272,209
Metered kWh	134,604,818			134,604,818		
Customer Charge	257,212	$11.50	$2,957,938	257,212	$11.50	$2,957,938
Number of Customers	257,820			257,820		
Fuel		$0.0023217	$312,514		$0.0023217	$312,514
Environmental Surcharge			$350,615			$0
Total			$14,121,390			$16,506,476

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
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SMALL GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (225)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-Peak	0	$0.13416	$0	0	$0.15326	$0
Off-Peak	0	$0.03853	$0	0	$0.04940	$0
Metered kWh	0			0		
Customer Charge	12	$15.10	$181	12	$15.10	$181
Number of Customers	12			12		
Fuel		$0.0023217	$0		$0.0023217	$0
Environmental Surcharge			$5			$0
Total			$186			$181

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

SMALL GENERAL SERVICE - NON METERED (204, 213)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 500 kWh	1,987,491	$0.10013	$199,007	1,987,491	$0.13160	$261,554
Over 500 kWh	1,211,652	$0.05994	$72,626	1,211,652	$0.07116	$86,221
Metered kWh	3,199,143			3,199,143		
Customer Charge	18,793	$7.50	$140,948	18,793	$7.50	$140,948
Number of Customers	13,668			13,668		
Fuel		$0.0023217	$7,427		$0.0023217	$7,427
Environmental Surcharge			$10,334			$0
Total			$430,343			$496,150

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
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MEDIUM GENERAL SERVICE - RECREATIONAL LIGHTING (214)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
All kWh	1,794,638	$0.07708	$138,331	1,794,638	$0.09004	$161,589
Metered kWh	1,794,638			1,794,638		
Customer Charge	847	$13.50	$11,435	847	$13.50	$11,435
Number of Customers	900			900		
Fuel		$0.0023217	$4,167		$0.0023217	$4,167
Environmental Surcharge			$3,880			$0
Total			$157,811			$177,190

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

MEDIUM GENERAL SERVICE - SECONDARY (215, 216, 218)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 200 kWh per kW	346,095,070	$0.08177	$28,300,194	346,095,070	$0.09862	$34,131,896
Over 200 kWh per kW	195,685,030	$0.07015	$13,727,305	195,685,030	$0.08460	$16,554,954
Minimum kWh	0			0		
Metered kWh	541,780,100			541,780,100		
Billing kW						
Standard	2,205,103	$1.31	$2,888,685	2,205,103	$1.64	$3,616,369
Mining Minimum	0	$5.46	$0	0	$6.84	$0
Customer Charge	88,823	$13.50	$1,199,111	88,823	$13.50	$1,199,111
Number of Customers	88,992			88,992		
Fuel		$0.0023217	$1,257,858		$0.0023217	$1,257,858
Environmental Surcharge			$1,230,890			$0
Total			$48,604,041			$56,760,186

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

MEDIUM GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (223)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	438,944	$0.12580	$55,219	438,944	$0.14801	$64,968
Off-peak kWh	932,596	$0.03970	$37,024	932,596	$0.05130	$47,842
Metered kWh	1,371,540			1,371,540		
Customer Charge	624	$3.00	$1,872	624	$3.00	$1,872
Number of Customers	624			624		
Fuel		$0.0023217	$3,184		$0.0023217	$3,184
Environmental Surcharge			$2,314			$0
Total			$99,614			$117,867

KENTUCKY POWER BILLING ANALYSIS
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MEDIUM GENERAL SERVICE TIME-OF-DAY (229)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	1,754,775	$0.12580	$220,751	1,754,775	$0.14801	$259,724
Off-peak kWh	2,903,465	$0.03970	$115,268	2,903,465	$0.05130	$148,948
Metered kWh	4,658,240			4,658,240		
Customer Charge	1,021	$14.30	$14,600	1,021	$14.30	$14,600
Number of Customers	1,020			1,020		
Fuel		$0.0023217	$10,815		$0.0023217	$10,815
Environmental Surcharge			$9,556			$0
Total			$370,990			$434,087

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
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MEDIUM GENERAL SERVICE - PRIMARY (217, 220)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 200 kWh per kW	14,634,903	$0.07507	$1,098,642	14,634,903	$0.09054	$1,325,044
Over 200 kWh per kW	6,619,961	$0.06715	$444,530	6,619,961	$0.08098	$536,084
Minimum kWh	212,912			212,912		
Metered Voltage Adj.	(726)			(726)		
Metered kWh	21,467,050			21,467,050		
Billing kW						
Standard	75,839	$1.28	$97,074	75,839	$1.59	$120,584
Mining Minimum	8,334	$5.46	$45,504	8,334	$6.84	$57,005
Customer Charge	925	$21.00	$19,425	925	$25.00	$23,125
Number of Customers	936			936		
Fuel		$0.0023217	$49,840		$0.0023217	$49,840
Environmental Surcharge			$41,216			$0
Total			$1,796,231			$2,111,682

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

MEDIUM GENERAL SERVICE - SUBTRANSMISSION (236)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 200 kWh per kW	5,048,746	$0.06933	$350,030	5,048,746	$0.08361	$422,126
Over 200 kWh per kW	2,505,669	$0.06510	$163,119	2,505,669	$0.07851	$196,720
Minimum kWh	75,133			75,133		
Metered kWh	7,629,548			7,629,548		
Billing kW						
Standard	26,015	$1.25	$32,519	26,015	$1.55	$40,323
Mining Minimum	1,835	$5.46	$10,019	1,835	$6.84	$12,551
Customer Charge	166	$153.00	$25,398	166	$182.00	$30,212
Number of Customers	168			168		
Fuel		$0.0023217	$17,714		$0.0023217	$17,714
Environmental Surcharge			$13,093			$0
Total			$611,891			$719,646

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

LARGE GENERAL SERVICE - SECONDARY (240, 242)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	577,461,697	$0.06309	$36,432,058	577,461,697	$0.07795	$45,013,139
Metered Voltage Adj.	36,642			36,642		
Metered kWh	577,498,339			577,498,339		
Billing kW	1,606,539	$3.45	$5,542,560	1,606,539	$4.02	$6,458,287
Excess kVA	50,257	$2.97	$149,263	50,257	$3.46	$173,889
Customer Charge	8,613	$85.00	$732,105	8,613	$85.00	$732,105
Number of Customers	8,616			8,616		
Fuel		$0.0023217	$1,340,785		$0.0023217	$1,340,785
Environmental Surcharge			$1,148,128			$0
Total			$45,344,899			$53,718,205

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

LARGE GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (251)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	1,284,601	$0.10781	$138,493	1,284,601	$0.12971	$166,626
Off-peak kWh	1,796,881	$0.03942	$70,833	1,796,881	$0.05116	$91,928
Metered kWh	3,081,482			3,081,482		
Customer Charge	108	$81.80	$8,834	108	$81.80	$8,834
Number of Customers	108			108		
Fuel		$0.0023217	$7,154		$0.0023217	$7,154
Environmental Surcharge			$6,257			$0
Total			$231,572			$274,543

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
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LARGE GENERAL SERVICE - PRIMARY (244, 246)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	104,787,360	$0.05604	$5,872,284	104,787,360	$0.06514	$6,825,849
Metered Voltage Adj.	(22,492)			(22,492)		
Metered kWh	104,764,868			104,764,868		
Billing kW	432,390	$3.36	$1,452,830	432,390	$3.89	$1,681,997
Excess kVA	70,343	$2.97	$208,919	70,343	$3.46	$243,387
Customer Charge	1,118	$127.50	$142,545	1,118	$127.50	$142,545
Number of Customers	1,116			1,116		
Fuel		$0.0023217	$243,234		$0.0023217	$243,234
Environmental Surcharge			$202,251			$0
Total			$8,122,063			$9,137,011

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

LARGE GENERAL SERVICE - SUBTRANSMISSION (248)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	78,827,849	$0.04539	$3,577,996	78,827,849	$0.04942	$3,895,672
Metered Voltage Adj.	(43,284)			(43,284)		
Metered kWh	78,784,565			78,784,565		
Billing kW	271,247	$3.30	$895,115	271,247	$3.80	$1,030,739
Excess kVA	63,743	$2.97	$189,317	63,743	$3.46	$220,551
Customer Charge	599	$535.50	$320,765	599	$535.50	$320,765
Number of Customers	600			600		
Fuel		$0.0023217	$182,915		$0.0023217	$182,915
Environmental Surcharge			$130,800			$0
Total			$5,296,907			$5,650,641

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

QUANTITY POWER - SECONDARY (356)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	5,205,323	$0.03285	$170,995	5,205,323	$0.03285	$170,995
Metered kWh	5,205,323			5,205,323		
Billing kW						
On-Peak	8,718	$13.28	$115,775	8,718	$18.51	$161,370
Off-Peak Excess	0	$4.79	$0	0	$8.65	$0
Billing KVAR	13	$0.67	$9	13	$0.69	$9
Customer Charge	12	$276.00	$3,312	12	$276.00	$3,312
Number of Customers	12			12		
Fuel		$0.0023217	$12,085		$0.0023217	$12,085
Environmental Surcharge			$8,046			$0
Total			$310,222			$347,771

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

QUANTITY POWER - PRIMARY (357, 358)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	414,586,441	$0.03233	$13,403,580	414,586,441	$0.03233	$13,403,580
Metered Voltage Adj.	(50,673)			(50,673)		
Metered kWh	414,535,768			414,535,768		
Billing kW						
On-Peak	955,233	$11.53	$11,013,836	955,233	$15.00	$14,328,495
Off-Peak Excess	5,340	$3.31	$17,675	5,340	$5.56	$29,690
Alternate Feed	30,392	$4.04	$122,784	30,392	$4.34	$131,901
Billing KVAR	162,132	$0.67	$108,628	162,132	$0.69	$111,871
Customer Charge	588	$276.00	$162,288	588	$276.00	$162,288
Number of Customers	588			588		
Fuel		$0.0023217	$962,433		$0.0023217	$962,433
Environmental Surcharge			$673,570			$0
Total			$26,464,795			$29,130,258

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

QUANTITY POWER - SUBTRANSMISSION (359)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	438,609,128	$0.03201	$14,039,878	438,609,128	$0.03201	$14,039,878
Metered Voltage Adj.	(113,116)			(113,116)		
Metered kWh	438,496,012			438,496,012		
Billing kW						
On-Peak	1,091,478	$8.81	$9,615,921	1,091,478	$10.13	$11,056,672
Off-Peak Excess	6,885	$0.88	$6,059	6,885	$1.20	$8,262
Billing KVAR	319,807	$0.67	$214,271	319,807	$0.69	$220,667
Customer Charge	396	$662.00	$262,152	396	$662.00	$262,152
Number of Customers	396			396		
Fuel		$0.0023217	$1,018,062		$0.0023217	$1,018,062
Environmental Surcharge			$656,716			$0
Total			$25,813,058			$26,605,693

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

QUANTITY POWER - TRANSMISSION (360)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	39,572,710	$0.03176	$1,256,829	39,572,710	$0.03176	$1,256,829
Metered Voltage Adj.	(162,820)			(162,820)		
Metered kWh	39,409,890			39,409,890		
Billing kW						
On-Peak	119,865	$7.47	$895,392	119,865	$9.00	$1,078,785
Off-Peak Excess	322	$0.77	$248	322	$1.10	$354
Billing KVAR	30,446	$0.67	$20,399	30,446	$0.69	$21,008
Customer Charge	48	$1,353.00	$64,944	48	$1,353.00	$64,944
Number of Customers	48			48		
Fuel		$0.0023217	$91,498		$0.0023217	$91,498
Environmental Surcharge			$58,722			$0
Total			$2,388,032			$2,513,419

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

COMMERCIAL AND INDUSTRIAL POWER TIME-OF-DAY - SUBTRANSMISSION (371)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	1,930,765,109	$0.02849	$55,007,498	1,930,765,109	$0.02906	$56,108,034
Metered kWh	1,930,765,109			1,930,765,109		
Billing kW						
On-Peak	3,425,421	$10.83	$37,097,309	3,425,421	$12.06	$41,310,577
Off-Peak	3,416,326	$0.98	$3,347,999	3,416,326	$1.20	$4,099,591
Minimum	94,127	$11.80	$1,110,699	94,127	$12.17	$1,145,526
Maximum	3,570,102			3,570,102		
Billing KVAR	286,216	$0.67	$191,765	286,216	$0.69	$197,489
Customer Charge	168	$662.00	$111,216	168	$794.00	$133,392
Number of Customers	168			168		
Fuel		$0.0023217	$4,482,681		$0.0023217	$4,482,681
Environmental Surcharge			$2,609,172			$0
Total			$103,958,339			$107,477,290

KENTUCKY POWER BILLING ANALYSIS
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TEST YEAR ENDED SEPTEMBER 30, 2009

COMMERCIAL AND INDUSTRIAL POWER TIME-OF-DAY - TRANSMISSION (372)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	385,684,996	$0.02829	$10,911,029	385,684,996	$0.02880	$11,107,728
Metered kWh	385,684,996			385,684,996		
Billing kW						
On-Peak	611,061	$9.35	$5,713,420	611,061	$10.98	$6,709,450
Off-Peak	660,653	$0.84	$554,949	660,653	$1.10	$726,718
Minimum	163,144	$10.32	$1,683,646	163,144	$11.09	$1,809,267
Maximum	916,253			916,253		
Billing KVAR	60,448	$0.67	$40,500	60,448	$0.69	$41,709
Customer Charge	48	$1,353.00	$64,944	48	$1,353.00	$64,944
Number of Customers	48			48		
Fuel		$0.0023217	$895,450		$0.0023217	$895,450
Environmental Surcharge			$513,929			$0
Total			$20,377,867			$21,355,266

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

STREET LIGHTING (528)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
OH Service on Distribution Poles						
100 watts, 9,500 Lumens	93,468	$5.93	$554,265	93,468	$7.25	$677,643
150 watts, 16,000 Lumens	960	$6.85	$6,576	960	$8.30	$7,968
200 watts, 22,000 Lumens	28,488	$8.65	$246,421	28,488	$10.30	$293,426
400 watts, 50,000 Lumens	5,568	$12.88	$71,716	5,568	$16.05	$89,366
Service on New Wood Distribution Poles						
100 watts, 9,500 Lumens	6,108	$9.23	$56,377	6,108	$10.25	$62,607
150 watts, 16,000 Lumens	312	$10.20	$3,182	312	$11.40	$3,557
200 watts, 22,000 Lumens	6,348	$11.90	$75,541	6,348	$13.15	$83,476
400 watts, 50,000 Lumens	1,572	$16.13	$25,356	1,572	$18.45	$29,003
Service on New Metal or Concrete Poles						
100 watts, 9,500 Lumens	-	$15.13	$0	-	$18.90	$0
150 watts, 16,000 Lumens	-	$15.90	$0	-	$19.85	$0
200 watts, 22,000 Lumens	1,176	$20.20	$23,755	1,176	$25.25	$29,694
400 watts, 50,000 Lumens	852	$21.98	$18,727	852	$27.45	$23,387
Metered kWh	8,485,771			8,485,771		
Fuel		$0.0023217	$19,702		$0.0023217	$19,702
Environmental Surcharge			$27,829			$0
Total			$1,129,448			$1,319,830

KENTUCKY POWER BILLING ANALYSIS
PROFORMA - SETTLEMENT
TEST YEAR ENDED SEPTEMBER 30, 2009

MUNICIPAL WATERWORKS (540)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
All kWh	7,802,389	$0.06866	$535,712	7,802,389	$0.08300	$647,598
Minimum kWh	19,035			19,035		
Metered kWh	7,821,424			7,821,424		
Minimum kW	2,338	$3.65	$8,534	2,338	$4.10	$9,586
Customer Charge	240	$22.90	$5,496	240	$22.90	$5,496
Number of Customers	240			240		
Fuel		$0.0023217	$18,159		$0.0023217	$18,159
Environmental Surcharge			$14,797			$0
Total			$582,698			$680,839