COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In The Matter Of:

APPLICATION OF KENTUCKY POWER COMPANY FOR APPROVAL OF ITS 2011 ENVIRONMENTAL COMPLIANCE PLAN, FOR APPROVAL OF ITS AMENDED ENVIRONMENTAL COST RECOVERY SURCHARGE TARIFF, AND FOR THE GRANTING OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE CONSTRUCTION AND ACQUISITION OF RELATED FACILITIES

CASE NO. 2011-00401

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FEB 07 2012
PUBLIC SERVICE COMMISSION

Notice of Filing Of Complete Responses To Identified Data Requests

Kentucky Power Company files the complete responses to the following data requests:

(a) Sierra Club 1-8;

(b) Sierra Club 1-10;

(c) Sierra Club 1-15;

(d) Sierra Club 1-17;

(e) Sierra Club 1-18;

(f) Sierra Club 1-25;

(g) Sierra Club 1-27 (referenced CD previously filed);

(h) Sierra Club 1-31;

(i) Sierra Club 1-36;

(j) Sierra Club 1-42;

(k) Sierra Club 1-49;

(l) Sierra Club 1-52;

(m) Sierra Club 1-53;

(n) Sierra Club 1-61.

This the 7th day of February, 2012.

Respectfully submitted,

Mark R. Overstreet
R. Benjamin Crittenden
STITES & HARBISON, PLLC
421 West Main Street
P.O. Box 634
Frankfort, KY 40602-0634
Telephone: (502) 223-3477
COUNSEL FOR KENTUCKY POWER COMPANY

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by first class mail, postage prepaid, upon the following parties of record, this the 7th day of February, 2012.

Michael L. Kurtz
Kurt J. Boehm
Boehm, Kurtz & Lowry
Suite 1510
36 East Seventh Street
Cincinnati, OH 45202

Joe F. Childers
Joe F. Childers & Associates
300 The Lexington Building
201 West Short Street
Lexington, KY 40507

Jennifer Black Hans
Dennis G. Howard II
Lawrence W. Cook
Assistant Attorney General
Office for Rate Intervention
P.O. Box 2000
Frankfort, KY 40602-2000

Kristin Henry
Sierra Club
85 Second Street
San Francisco, CA 94105

Mark R. Overstreet

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PUBLIC SERVICE
COMMISSION

Kentucky Power Company

REQUEST

Please describe current demand-side management (DSM) programs offered by AEP and KPC, including demand-response, interruptible load, and efficiency programs. Please note the cost, MW or MWh reductions, expected life, and penetration of these programs.

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.

A description of the current DSM programs offered by Kentucky Power is provided with the residential and business promotion sheets shown on Attachments 1 and 2.

The DSM program activity levels including program expense is shown on Attachment 3. DSM programs are normally evaluated on a three-year cycle and considered for renewal based on various factors including the program cost and benefits.

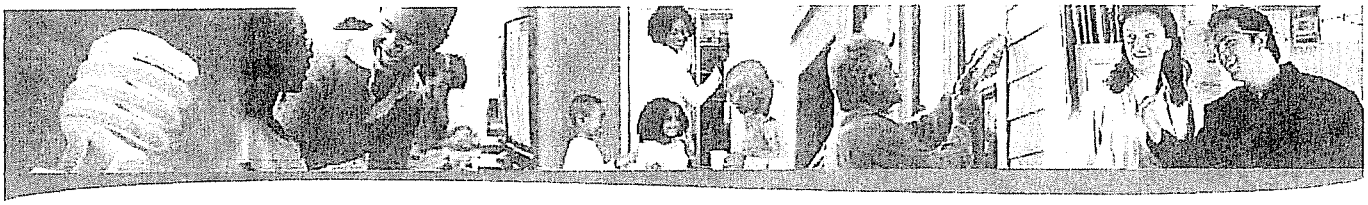
WITNESS: Ranie K Wohnhas

KENTUCKY POWER

A unit of American Electric Power

Energy Efficiency Programs for Residential Customers

kentuckypower.com/save



Community Outreach Compact Fluorescent Lighting Program... Customers attending company-sponsored community events can receive information on energy efficiency as well as a package of four high efficiency 23- watt compact fluorescent lights. Community outreach events are posted at kentuckypower.com.

Energy Education for Students Program... An energy efficiency education program for 7th grade students that includes classroom presentations and take-home CFLs. Offered in conjunction with the National Energy Educational Development Project (NEED) at participating schools in our service area.

High Efficiency Heat Pump Program... Replace your home's central electric resistance heating or heat pump system with a qualifying energy-efficient heat pump and receive a $400 incentive. Contact a participating HVAC dealer in your area or contact us at 1-800-572-1113.

High Efficiency Heat Pump – Mobile Home Program... Upgrade your mobile home's central electric resistance heating with a qualifying energy-efficient heat pump and receive a $400 incentive. Contact a participating HVAC dealer in your area or contact us at 1-800-572-1113.

HVAC Diagnostic and Tune-up Program... Purchase a qualifying central HVAC tune-up and diagnostic service on a central air conditioner or heat pump system from a participating HVAC contractor and get a $50 incentive. Call 1-800-572-1113 or visit kentuckypower.com/save to find a participating dealer.

Mobile Home New Construction Program... Receive a $500 incentive when you purchase a new mobile home with qualifying efficient insulation and heat pump. Contact a participating manufactured home dealer or contact us at 1-800-572-1113.

Modified Energy Fitness Program... Home energy audits that include energy-saving items and recommendations are available at no charge to qualifying customers who live in all-electric, single family homes and who used an average of 1,000 kWh per month over the last 12 months. Eligible customers can call 1-866-225-0686 to schedule an audit appointment.

Residential Efficient Products... Instant discounts on ENERGY STAR® lighting, including compact fluorescent light bulbs (CFLs) at over 20 retail stores. Visit kentuckypower.com/save for a list of participating stores or to shop the online SMART Lighting store for a variety of CFLs, holiday lights, nightlights and ceiling fans.

Targeted Energy Efficiency Program... Funding provided to community action agencies to help qualifying customers with energy efficiency home improvements that reduce their energy bills and improve their homes' safety and comfort. Contact your county's community action agency to determine if you qualify. To find your agency, visit capky.org or call 1-800-456-3452.

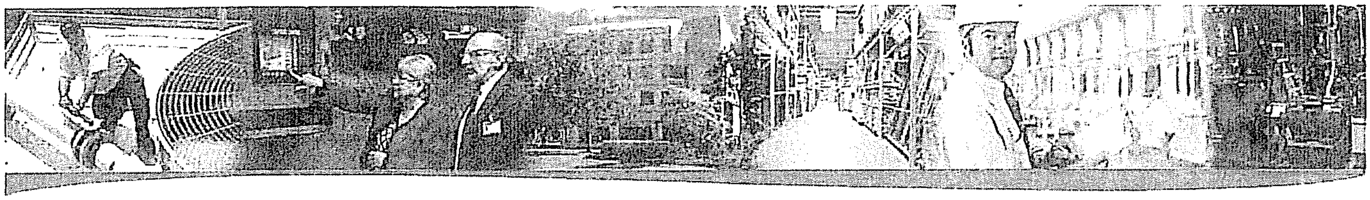
SMART Energy Management Program... Customers with central electric cooling systems and electric water heaters can save money and energy with this pilot load management program. You'll receive a free programmable thermostat professionally installed at no charge and up to a total of $28 in bill credits. Plus, you'll have access to our online tool that allows you to see detailed information about how much energy you're using and what it costs. Visit kentuckypower.com/go/smartenergy to learn more, check eligibility or enroll.

AEP KENTUCKY POWER

A unit of American Electric Power

Energy Efficiency Programs for Business Customers

kentuckypower.com/save



Commercial Incentive Program... All commercial customers can take advantage of this convenient way to receive incentives for common energy efficiency projects. Incentives are available for a variety of energy-saving improvements and technologies in existing buildings and new construction projects. Choose from a menu of standardized incentives for high efficiency lighting, HVAC (heating, ventilation and air conditioning), and food service and refrigeration. The maximum incentive is 50% of incremental equipment costs, up to $20,000 annually per customer account. Other limits may apply. Email kpcommercialincentive@kema.com or call 1-855-878-6207 for more information.

Small Commercial HVAC Diagnostic and Tune-up Program... A $75 incentive is available to qualifying small commercial customers who receive a central HVAC tune-up and diagnostic service from a participating, state licensed contractor. Small commercial customers using less than 100 kW peak demand are eligible to participate. Call 1-800-572-1113 or visit kentuckypower.com/save to find a participating dealer.

Small Commercial High Efficiency Heat Pump / Air Conditioning Program... Eligible small commercial customers can offset the cost of upgrading to a new, efficient central air conditioning or heat pump system with these incentives. Incentives range from $250 to $450. Small commercial customers using less than 100 kW peak demand and whose primary heat source is electricity can qualify for this program. Contact a participating HVAC dealer in your area or contact us at 1-800-572-1113.

SMART Energy Management Program... Small commercial customers (using less than 100 kW peak demand) with central electric cooling systems and electric water heaters can save money and energy with this pilot load management program. You'll receive a free programmable thermostat professionally installed at no charge and up to a total of $28 in bill credits. Plus, you'll have access to our online tool that allows you to see detailed information about how much energy you're using and what it costs. Visit kentuckypower.com/go/smartenergy to learn more, check eligibility or enroll.

ACTIVE KPCO DSM PROGRAMS:
As of December 31, 2011:

PROGRAM	START DATE	PROGRAM COST	TOTAL COST	PROGRAM TO DATE MW - SUMMER	MW - WINTER	MWH	PARTICIPANTS	MARKET PENETRATION
Residential								
TARGETED ENERGY FITNESS	1996	$3,716,149	$0	0.735	3.070	89,716	4,400	N/A (1)
HIGH EFFICIENCY HEAT PUMP - MOBILE HOME	1996	$1,185,078	$0	0.439	4.092	87,525	2,488	12.82%
MOBILE HOME NEW CONSTRUCTION	1998	$1,342,547	$0	0.683	5.130	128,163	2,305	N/A (2)
MODIFIED ENERGY FITNESS	2003	$3,013,392	$0	1.018	4.389	82,128	8,191	13.10%
HIGH EFFICIENCY HEAT PUMP (3)	2009	$787,936	$0	0.137	1.890	2,198	1,132	0.97%
COMMUNITY OUTREACH CFL	2009	$150,768	$0	0.295	0.484	1,003	13,469	9.17%
ENERGY EDUCATION FOR STUDENTS	2009	$71,939	$0	0.116	0.125	288	4,573	N/A (4)
RESIDENTIAL HVAC DIAGNOSTIC & TUNE-UP	2010	$103,074	$0	0.186	0.184	272	990	0.67%
PILOT RESIDENTIAL LOAD MANAGEMENT	2011	$103,498	$0	0.000	0.000	0	5	0.00%
RESIDENTIAL EFFICIENT PRODUCTS (UNITS)	2011	$314,155	$0	0.148	1.484	2,231	133,692	N/A (5)
Commercial								
COMMERCIAL HVAC DIAGNOSTIC & TUNE-UP	2011	$27,093	$0	0.060	0.060	77	153	0.56%
COMMERCIAL LOAD MANAGEMENT	2011	$14,315	$0	0.000	0.000	0	0	0.00%
COMMERCIAL HIGH EFFICIENCY HP/AC	2011	$23,516	$0	0.005	0.008	15	24	0.09%
COMMERCIAL INCENTIVE	2011	$252,314	$0	0.045	0.079	21	18	0.06%
TOTAL		$11,105,774	$0	3.867	20.995	393,634	171,440	

(1) - The total number of low income customers within the KPCO service area is currently not available.
(2) - The Mobile Home New Construction program represents KPCO customers receiving new electric service to manufactured housing.
(3) - The market penetration for this program assumes all residential customers are eligible. Data representing customers already owning a reliable heat pump system, is currently not available.
(4) - Most schools within the KPCO area participate in this education program targeted to 7th grade science students.
(5) - Market penetration data for the Residential Efficient Products program is currently not available.

Kentucky Power Company

REQUEST

Please provide any DSM potential studies performed by or for AEP and/or KPC in the last five years, including attendant workbooks or calculations. Please describe if or how these studies are incorporated into the current case. If they are not, why not?

RESPONSE

Please see the attachments to this response. All of the programs described in the attachments were approved by the Commission and implemented by the Company.

WITNESS: Ranie K Wohnhas

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AUG 25 2008

PUBLIC SERVICE
COMMISSION

AEP
KENTUCKY POWER
A unit of American Electric Power

Kentucky Power
P O Box 5190
101A Enterprise Drive
Frankfort, KY 40602
KentuckyPower.com

Stephanie L. Stumbo, Executive Director
Kentucky Public Service Commission
P. O. Box 615
211 Sower Boulevard
Frankfort, KY 40602

August 25, 2008

Dear Ms. Stumbo:

Re: Case No. 2008-00349

In the Matter of the Joint Application Pursuant to 1994 House Bill No. 501 for the Approval of Kentucky Power Company Collaborative Demand-Side Management Programs, and for Authority to Recover Costs, Net Lost Revenues and Receive Incentives associated with the Implementation of Three New Residential Demand-Side Management Programs beginning January 1, 2009.

The Joint Applicants seek authority for Kentucky Power Company, to implement three new residential DSM programs to recover costs including net lost revenues and incentives related to those programs.

In this filing, the DSM Collaborative is requesting Commission approval of a new High Efficiency Heat Pump Program. This program will be targeted to residential customers living in site-built homes within the Kentucky Power service territory that utilize an electric central heating and cooling system. A financial incentive will be provided to participating customers who up-grade to a high-efficiency heat pump that meets program guidelines. HVAC dealers installing qualifying equipment in customer homes are also eligible for an incentive.

The DSM Collaborative is also requesting approval of a new Energy Education for Students Program. Kentucky Power Company (KPCo) will partner with the National Energy Education Development Project (NEED) to implement an energy education program targeted to 7^{th} grade students at participating middle schools throughout the KPCo service territory. Educational materials on energy, electricity, environment and economics will be provided. The program will also provide a package of four 23 watt compact fluorescent lamps (CFLs) that will allow students to install the CFLs in their homes as part of the curriculum.

Finally, the DSM Collaborative is requesting approval of a new Community Outreach Compact Fluorescent Lighting (CFL) Program. This program is designed to educate and encourage KPCo residential customers to purchase and use compact fluorescent lighting (CFLs) in their homes. A package of four-23 watt CFLs will be distributed to customers attending community outreach activities sponsored by KPCo.

As is customary, the Company requests the Commission provide a letter of acknowledgement of this filing. If you have any questions, please contact me at (502) 696-7010.

Sincerely,

Errol K. Wagner
Director of Regulatory Services

enclosure

Table of Contents

High Efficiency Heat Pump Program

1. DESCRIPTION

Kentucky Power Company (KPCo) will offer a financial incentive to residential customers living in site-built homes who purchase a new high-efficiency heat pump for upgrades of less efficient electric heating and cooling systems.

2. RATIONALE FOR PROGRAM

The high-efficiency heat pump program is designed to reduce residential electric energy consumption by upgrading less efficient electric heating and cooling systems with high-efficiency heat pumps. Advanced technology has increased the efficiency of heat pump systems, resulting in higher energy savings and a greater demand reduction. This program is appropriate, as it helps lower electric bills for all residential customers and allows KPCo to utilize its existing generating capacity more efficiently, thereby deferring the need for new generation as well as conserving our country's valuable natural resources.

3. PARTICIPATION GOALS

	Resistant Heat Replacement	Heat Pump Replacement
Jan. 2009 thru Dec. 2009	50	50
Jan. 2010 thru Dec. 2010	100	100
Jan. 2011 thru Dec. 2011	100	100

4. ELIGIBLE CUSTOMERS

Residential retail customers living in the KPCo service territory who currently utilize an electric central heating and cooling system (or plan to install a central cooling system) are eligible to participate and receive financial incentives. Dealers installing qualifying equipment in homes of customers as outlined above will also be eligible to receive an incentive.

5. INCENTIVES

KPCo will offer customers and the HVAC dealer a financial incentive according to predetermined guidelines based on the efficiency (cooling SEER, heating HSPF) of the installed unit. The incentive will be structured as follows:

For upgrades of an **electric resistance heating system** with a high efficiency heat pump unit (SEER greater than or equal to 13; HSPF greater than or equal to

7.7), the residential customer will receive an incentive of $400.00. An incentive of $50.00 will be given to the participating HVAC dealer.

For upgrades of an **electric heat pump unit** with a ultra-high efficiency heat pump unit (SEER greater than or equal to 14; HSPF greater than or equal to 8.2), the residential customer will receive an incentive of $400.00. An incentive of $50.00 will be given to the participating HVAC dealer.

5. IMPLEMENTATION PLAN

A. Promotion

KPCo will develop relationships with trade allies (i.e., manufacturers, dealers, and contractors) in order to promote high-efficiency heat pump technology. Media advertising, such as newspaper, radio, television, and billboard, may also be used. A co-op advertising program may be offered to trade allies where the Company would share the cost of advertisements promoting high-efficiency heat pumps.

B. Delivery

KPCo representatives will work in conjunction with trade allies to promote high efficiency heat pumps in place of less efficient electric heating and cooling systems.

C. Quality Assurance

The program will be regularly reviewed by KPCo staff responsible for the program as well as the Company's DSM Collaborative. The Company will maintain communication with trade allies as well as respond to any customer inquiries. A selected sample of installations will be inspected to verify quality of installation.

D. Evaluation

KPCo will perform an evaluation relating to the program's impact and processes, including program objectives, data collection procedures, quality assurance methodologies, reporting timelines, costs, and the program's cost/benefit analyses.

The program evaluation objectives will be to:

1. Assess participant satisfaction with the program;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy efficiency;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;

5. Assess the effectiveness of program delivery mechanisms.

6. TIMELINE

Action	Start	End
Program Approval	08/08	10/08
Implementation	01/09	12/11
Evaluation	01/10 01/11	06/10* 06/11*

* Evaluation report will be provided on 08/15/10 and 08/15/11.

7. ANNUAL BUDGET

	Year 1	Year 2	Year 3
Program Incentives	$45,000	$ 90,000	$ 90,000
Promotion	$ 8,000	$ 8,000	$ 8,000
Evaluation	$ 0,000	$ 7,000	$ 7,000
TOTAL COSTS	$53,000	$105,000	$105,000

8. EXPECTED SAVINGS / BENEFITS

a. Anticipated load Impact Per Participant :

Upgrading Resistant Heat to Heat Pump Customers:

Energy Savings Per Year	=	4,176	kWh
Demand Reduction	=	2.900	kW
	(@ system	winter peak)	
	=	0.000	kW
	(@ system	summer peak)	

Upgrading Heat Pump Customers:

Energy Savings Per Year	=	858	kWh
Demand Reduction	=	0.444	kW
	(@ system	winter peak)	
	=	0.235	kW
	(@ system	summer peak)	

b. Annual Expected Program Savings/Benefits (including T&D losses) @ 200 units in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
18 kW	327 kW	462 MWh

Projected energy savings and demand reductions are estimated based on the anticipated number of installations. The estimated effects of freeriders are included.

c. Projected Program MWh Savings and kW Reduction Assuming Participation (Including T&D losses):

Goal of 500 units is achieved (all customers in three years)

Energy Savings	=	1,155 MWh
Demand Reduction	=	818 kW
		(@ system winter peak)
	=	45 kW
		(@ system summer peak)

9. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

a.	Total Resource Cost	=	2.64
b.	Ratepayer Impact Measure	=	1.59
c.	Participant	=	1.93
d.	Utility Cost	=	5.40

ENERGY EDUCATION FOR STUDENTS PROGRAM

1. DESCRIPTION

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

2. ELIGIBLE PARTICIPANTS

All 7th grade students at participating schools will be eligible for the program.

3. PARTICIPATION GOALS

Jan. 2009 through Dec. 2009	1,200 Students
Jan. 2010 through Dec. 2010	1,700 Students
Jan. 2011 through Dec. 2011	2,000 Students

4. IMPLEMENTATION PLAN

A. Promotion

NEED staff will conduct training workshops on a scheduled basis to ensure all participating schools are reached during a calendar year. Educational materials on energy, electricity, environment and economics will be provided. The program will also provide a package of four 23 watt compact fluorescent lamps (CFLs) that will allow students to directly install the CFLs in their homes as it relates to the curriculum. This allows learning and direct savings from the program.

B. Delivery

NEED staff will mail invitations to each middle school within the KPCo service territory. KPCo and NEED staff members will coordinate the enrollment of participating schools, delivery of educational materials & compact fluorescent lamps and scheduling of educational workshops.

5. EVALUATION

A. Goals

KPCo will perform an evaluation assessing and documenting the program's processes and estimating the program's impacts as well as performing a benefit/cost analysis.

B. **Objectives**

The program evaluation objectives will be to:

1. Assess educator and student satisfaction with the program;
2. Gain insight into the potential for expanding the program to additional grade levels;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to educators and students;
4. Assess the program's cost-effectiveness based on various economic tests;

6. TIMELINE

Action	Start	End
Program Approval	08/08	10/08
Implementation	01/09	12/11
Evaluation	01/10 01/11	06/10* 06/11*

* Evaluation report will be provided on 08/15/10 and 08/15/11.

7. ANNUAL BUDGET

	Year 1	Year 2	Year 3
Program Development & Administration	$ 4,000	$ 3,000	$ 3,000
Promotion	$ 1,000	$ 1,000	$ 1,000
Educational Workshops (Includes food costs)	$ 5,000	$ 5,000	$ 5,000
Compact Fluorescent Lamps	$12,000	$17,000	20,000
Evaluation	$ 0,000	$ 5,000	$ 5,000
TOTAL COSTS	$22,000	$31,000	$34,000

8. EXPECTED SAVINGS / BENEFITS

a. Anticipated load Impact Per Lamp:

Energy Savings Per Year	=	46	kWh
Demand Reduction	=	.023	kW
	(@ system winter peak)		
	=	.001	kW
	(@ system summer peak)		

b. Annual Expected Program Savings/Benefits @ 4,800 CFLs in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
14	359	220.8

Projected energy savings and demand reductions are estimated based on the anticipated number of students living within the KPCo service territory and installing compact fluorescent lamps in their homes.

c. Projected Program MWh Savings and kW Reduction Assuming Participation:

Goal of 19,600 CFLs is achieved (all students in three years)

Energy Savings	=	717.6	MWh
Demand Reduction	=	110	kW
	(@ system winter peak)		
	=	4	kW
	(@ system summer peak)		

9. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

a.	Total Resource Cost	=	8.09
b.	Ratepayer Impact Measure	=	2.39
c.	Participant	=	28.73
d.	Utility Cost	=	12.55

Community Outreach Compact Fluorescent Lighting (CFL) Program

1. DESCRIPTION

This program is designed to educate and influence Kentucky Power Company (KPCo) residential customers to purchase and use compact fluorescent lighting (CFLs) in their homes. To encourage customers to purchase CFLs as replacements for incandescent bulbs, a package of four 23 watt CFLs will be distributed to customers attending community outreach activities sponsored by KPCo.

2. ELIGIBLE PARTICIPANTS

Residential retail customers in Kentucky Power's service territory are eligible to participate.

3. PARTICIPATION GOALS

Jan. 2009 through Dec. 2009	3,500 customers
Jan. 2010 through Dec. 2010	4,000 customers
Jan. 2011 through Dec. 2011	4,000 customers

4. IMPLEMENTATION PLAN

A. Promotion

KPCo will promote the CFL program through the use of Consumer Circuit, advertising and community outreach activities. Consumer Circuit will be cycled through the KPCo's service territory.

B. Delivery

KPCo will devise and implement procedures to obtain the customer's account number, his/her name and electric service billing address in order for the CFL to be provided to KPCo customers (information will be used for follow up measurement and verification, and customer satisfaction).

5. EVALUATION

A. Goals

KPCo will perform an evaluation assessing and documenting the program's processes and estimating the program's impacts as well as performing a benefit/cost analysis.

B. Objectives

The program evaluation objectives are to:

1. Assess participant satisfaction with the program; Survey
2. Quantify the participant characteristics, participation rate, and installation rate.
3. Estimate the program impacts, including energy savings (kWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;
5. Assess the effectiveness of program delivery mechanisms.

C. Methodology

KPCo or its contractor/affiliate will periodically survey the parties receiving the compact fluorescent lamps. Survey questions will address customer satisfaction, installation information, program awareness, hours of operation, and future purchase intentions, and customer status.

6. TIMELINE

Action	Start	End
Program Approval	08/08	10/08
Implementation	01/09	12/11
Evaluation	01/10 01/11	06/10* 06/11*

* Evaluation report will be provided on 08/15/10 and 08/15/11.

7. ANNUAL BUDGET

	Year 1	Year 2	Year 3
CFLs	$35,000	$40,000	$40,000

Promotion	\$ 3,200	\$ 3,900	\$ 4,000
Administration	\$ 2,000	\$ 2,000	\$ 2,000
Evaluation	\$ 0,000	\$ 8,000	\$ 8,000
TOTAL COSTS	\$40,200	\$53,900	\$54,000

8. EXPECTED SAVINGS / BENEFITS

a. Anticipated Load Impact Per Lamp :

Energy Savings Year = 46 kWh
Demand Reduction = .023 kW
(@ system winter peak)
= .001 kW
(@ system summer peak)

b. Annual Expected Program Savings/Benefits @ 14,000 bulbs in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
13	322	644

Projected energy savings and demand reductions are estimated based on the anticipated number of compact fluorescent lamps installed. Estimated effects of freeriders are not included.

c. Projected Program MWh Savings and kW Reduction Assuming Participation :

Goal of 46,000 bulbs is achieved (all customers in three years)

Energy Savings = 2,116 MWh
Demand Reduction = 1.1 MW
(@ system winter peak)
= 0.42 MW
(@ system summer peak)

9. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

a.	Total Resource Cost	=	13.08
b.	Ratepayer Impact Measure	=	3.06
c.	Participant	=	29.05
d.	Utility Cost	=	30.28

KENTUCKY POWER®
A unit of American Electric Power

Kentucky Power
P O Box 5190
101A Enterprise Drive
Frankfort, KY 40602
KentuckyPower.com

Jeff R. Derouen, Executive Director
Kentucky Public Service Commission
P. O. Box 615
211 Sower Boulevard
Frankfort, KY 40602

February 26, 2010

Dear Mr. Derouen:

Re: Case No. 2010-00095

In the Matter of the Joint Application Pursuant to 1994 House Bill No. 501 for the Approval of Kentucky Power Company Collaborative Demand-Side Management Programs, and for Authority to Recover Costs, Net Lost Revenues And Receive Incentives associated with the Implementation of one New Residential, one combined Residential / Commercial and one Commercial Demand-Side Management program beginning January 1, 2010.

The Joint Applicants, with the exception of the Office of the Attorney General's representative who abstained, seek authority for Kentucky Power Company to implement one residential, one combined residential / commercial and one commercial DSM programs to recover costs including net lost revenues and incentives related to those programs.

In this filing, the DSM Collaborative is requesting Commission approval of a new Residential Efficient Products Program. This residential program will provide incentives and marketing support through retailers to build market share and usage of ENERGY STAR® lighting products to reduce the amount of lighting in a home. The program targets the purchase of lighting products through in-store promotion as well as special sales events. Customer incentives facilitate the increased purchase of high efficiency products.

The DSM Collaborative is also requesting approval of a HVAC Diagnostic and Tune-up Program. This program will be targeted to residential and small commercial customers within the Kentucky Power service territory that utilize an electric central air-conditioning or heat pump system. A financial incentive will be provided to participating customers who have a diagnostic performance of their central air-conditioner or heat pump system. HVAC dealers performing the diagnostic check are also eligible for an incentive.

The DSM Collaborative is also requesting approval of a Commercial High Efficiency Heat Pump / Air Conditioner Program. This program will be targeted to small commercial customers (< 100 kW demand) who purchase a new qualifying central air-conditioner or heat pump up to a 5-ton unit with a Consortium for Energy Efficiency rating . A financial incentive will be provided to participating customers who up-grade to a central air-conditioner or heat pump that meets program guidelines. HVAC dealers installing qualified equipment are also eligible for an incentive.

Finally, the DSM Collaborative is planning on filing a request for Commission approval for a Pilot Load Control Program and a Commercial Incentive Program no later than April 30, 2010.

As is customary, the Company requests the Commission provide a letter of acknowledgement of this filing. If you have any questions, please contact me at (502) 696-7010.

Sincerely,

Errol K. Wagner

Errol K. Wagner
Director of Regulatory Services

enclosure

Residential Efficient Products Program

1. DESCRIPTION

Kentucky Power Company (KPCo) will provide incentives and marketing support through retailers to build market share and usage of ENERGY STAR® lighting products to reduce the amount of lighting in a home. The program targets the purchase of lighting products through in-store promotion as well as special sales events. Customer incentives facilitate the increased purchase of high efficiency products while in-store signage, sales associate training and support makes provider participation easier.

2. RATIONALE FOR PROGRAM

The residential efficient products program will produce long-term energy savings in the residential sector by increasing the market share of ENERGY STAR® CFLs or other ENERGY STAR® lighting products sold through retail sales channels.

3. PARTICIPATION GOALS

Jan. 2010 through Dec. 2010	31,250 bulbs 200 other lighting products
Jan. 2011 through Dec. 2011	125,000 bulbs 800 other lighting products
Jan. 2012 through Dec. 2012	125,000 bulbs 800 other lighting products

4. ELIGIBLE CUSTOMERS

Residential retail customers in Kentucky Power's service territory are eligible to participate.

5. INCENTIVES

KPCo will provide monetary incentives as inducements for customers to purchase ENERGY STAR® high efficiency CFLs and/or other ENERGY STAR® lighting products as listed below:

- CFLs (Screw–In or Pin Based) Indoor and Outdoor for Replacement of Incandescent Lighting

- Ceiling Fan w/ENERGY STAR® Light Fixture
- LED Holiday Lights
- LED Night Lights

6. IMPLEMENTATION PLAN

KPCo will utilize a markdown approach as the primary driver of volume within the program. With a markdown approach, KPCo will reimburse select retailers for discounting the cost of ENERGY STAR® CFLs or other lighting products by a specified dollar amount per unit during special limited term promotions. The qualifying product would be listed at a lower retail price on store shelves or marked down automatically at the register. At the end of every month, the retailer provides a point of sale report and would be reimbursed for the discount provided on each unit that they have sold. This strategy eliminates costs associated with main-in rebate fulfillment and printing claim forms

7. EVALUATION

A. Goals

KPCo will perform an evaluation assessing and documenting the program's processes and estimating the program's impacts as well as performing a benefit/cost analysis.

B. Objectives

The program evaluation objectives are to:

1. Assess participant satisfaction with the program; Survey

2. Quantify the participant characteristics, participation rate, and installation rate.

3. Estimate the program impacts, including energy savings (kWh) and demand reduction (kW), and program value to customers;

4. Assess the program's cost-effectiveness based on various economic tests;

5. Assess the effectiveness of program delivery mechanisms.

C. Methodology

KPCo or its contractor/affiliate will periodically survey the parties receiving the ENERGY STAR® compact fluorescent lamps and/or other lighting products. Survey questions will address customer satisfaction, installation information, program awareness, hours of operation, and future purchase intentions, and customer status.

8. TIMELINE

Action	Start	End
Program Approval	02/10	06/10
Implementation	06/10	12/12
Evaluation	01/12	06/12*

* Evaluation report will be provided on 08/15/12.

9. ANNUAL BUDGET

	Year 1	Year 2	Year 3
CFL/ Markdowns	$ 31,250	$ 125,000	$ 125,000
Other Lighting Products Incentives	$ 1,100	$ 4,400	$ 4,400
Administration/Promotion*	$ 17,000	$ 55,000	$ 55,000
Evaluation	$ 1,000	$ 1,000	$ 15,000
TOTAL COSTS	$ 50,350	$ 185,400	$ 199,400

*Administration/Promotional Costs based on a Market Potential Study performed by SUMMIT BLUE Consulting, LLC, for a similar Residential Lighting Program for AEP – Appalachian Power Company.

10. EXPECTED SAVINGS / BENEFITS

a. Anticipated Load Impact Per CFL (Indoor Only):
- Energy Savings Year = 49.6 kWh
- Demand Reduction = 0.010 kW (@ system winter peak)
- = 0.001 kW (@ system summer peak)

b. Anticipated Load Impact Per Ceiling Fan w/ ENERGY STAR® Light fixture:
- Energy Savings Year = 180 kWh
- Demand Reduction = 0.026 kW (@ system winter peak)
- = 0.003 kW (@ system summer peak)

c. Anticipated Load Impact Per LED Holiday Lights (25 bulbs/string):
- Energy Savings Year = 3.6 kWh
- Demand Reduction = 0.000 kW (@ system winter peak)
- = 0.000 kW (@ system summer peak)

d. Anticipated Load Impact Per LED Night Light:
- Energy Savings Year = 21.9 kWh
- Demand Reduction = 0.001 kW (@ system winter peak)

= 0.000 kW (@ system summer peak)

e. Annual Expected Program Savings/Benefits (including T&D losses) @ 125,000 bulbs and 800 other lighting products in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
126	1,105	5,394

Projected energy savings and demand reductions are estimated based on the anticipated number of compact fluorescent lamps installed. Estimated effects of 20% freeriders are included.

f. Projected Program MWh Savings and kW Reduction Assuming Participation (including T&D losses):

Goal of 281,250 bulbs and 1,800 lighting products is achieved (all customers in three years)

Energy Savings	=	12,138 MWh
Demand Reduction	=	2,493 MW (@ system winter peak)
	=	243 MW (@ system summer peak)

11. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

a.	Total Resource Cost	=	1.48
b.	Ratepayer Impact Measure	=	0.47
c.	Participant	=	2.08
d.	Utility Cost	=	9.18

Commercial
High Efficiency Heat Pump / Air Conditioner
Program

1. DESCRIPTION

Kentucky Power Company (KPCo) will offer a financial incentive to small commercial customers (< 100 kW demand) who purchase a new qualifying central air conditioner or heat pump up to a 5-ton unit with a Consortium for Energy Efficiency $(CEE)_{SM}$ rating and who comply with pertinent eligibility requirements of the program.

2. RATIONALE FOR PROGRAM

The commercial high-efficiency heat pump / air conditioner program is designed to encourage the purchase of energy efficient central air conditioners and heat pumps identified by the U. S. Department of Energy (DOE), the U. S. Environmental Protection Agency (EPA) and/or the Consortium for Energy Efficiency (CEE) as being influential in energy efficiency. This program targets the existing retrofit market only.

This program is beneficial, as it helps lower electric bills for all commercial customers and allows KPCo to utilize its existing generating capacity more efficiently, thereby deferring or delaying the need for new generation as well as conserving our country's valuable natural resources.

3. PARTICIPATION GOALS

	Air Conditioner Replacement	Heat Pump Replacement
Jan. 2010 thru Dec. 2010	50	10
Jan. 2011 thru Dec. 2011	100	20
Jan. 2012 thru Dec. 2012	100	20

4. ELIGIBLE CUSTOMERS

Eligible existing retail small commercial customers must:

- Have unit installed at a location receiving electric service from KPCo;
- Have a maximum peak demand less than 100 kW over the previous 12 months;
- Install a central air conditioner or heat pump that meets the $(CEE)_{SM}$ guidelines as indicated by listing in the CEE/ARI Verified Directory.

Licensed HVAC dealers installing qualifying equipment will also be eligible to receive an incentive.

5. INCENTIVES

KPCo will provide monetary incentives as inducements for customers to purchase higher efficiency eligible central air conditioners and heat pumps meeting the specifications at the CEE Tier 1 level instead of baseline efficiency (i.e., standard) air conditioners and heat pumps. The incentive is designed to offset a portion of the additional cost involved with the qualified purchase of the higher efficiency central air conditioner or heat pump. KPCo will pay incentives for each central air conditioner or heat pump replaced based on the following tables:

Unitary Central Air Conditioner for Units Meeting CEE Specifications

Equipment Type	Size Category	Sub Category	CEE Tier 1
Air Cooled Cooling Mode	<65,000 Btu/h	Split System	14 SEER 12.0 EER
Air Cooled Cooling Mode	<65,000 Btu/h	Single Package	14 SEER 11.6 EER

KPCo will pay a $250 incentive for each central air conditioner equal to or less than 36,000 Btu/h. A $400 incentive will be paid for each central air conditioner greater than 36,000 Btu/h and less than 65,000 Btu/h. A $50 incentive will be paid to participating HVAC dealers for each air conditioner installed.

Unitary Heat Pump for Units Meeting CEE Specifications*

Equipment Type	Size Category	Sub Category	CEE Tier 1
Air Cooled Cooling Mode	<65,000 Btu/h	Split System	14 SEER 12.0 EER
Air Cooled Cooling Mode	<65,000 Btu/h	Single Package	14 SEER 11.6 EER
Air Cooled Heating Mode	<65,000 Btu/h	Split System	8.5 HSPF
Air Cooled Heating Mode	<65,000 Btu/h	Single Package	8.0 HSPF

KPCo will pay a $300 incentive for each heat pump equal to or less than 36,000 Btu/h. A $450 incentive will be paid for each heat pump greater than 36,000 Btu/h and less than 65,000 Btu/h. A $50 incentive will be paid to participating HVAC dealers for each heat pump installed.

*Eligibility for Central Heat Pump Incentive is limited to customers whose primary heating source is electricity.

6. IMPLEMENTATION PLAN

A. Promotion

KPCo will promote the program to its small commercial customers by written information in monthly electric bills, media promotion of eligible central air conditioners and heat pumps, direct contact, or other expeditious means.

KPCo will contact HVAC dealers in its service area to explain the program, encourage their participation, and provide educational outreach materials and incentive rebate forms.

B. Delivery

KPCo representatives will work in conjunction with trade allies to promote high efficiency air conditioners / heat pumps in place of less efficient electric heating and cooling systems.

C. Quality Assurance

The program will be regularly reviewed by KPCo staff responsible for the program as well as the Company's DSM Collaborative. The Company will maintain communication with trade allies as well as respond to any customer inquiries. A selected sample of installations will be inspected to verify quality of installation.

D. Evaluation

KPCo will perform an evaluation relating to the program's impact and processes, including program objectives, data collection procedures, quality assurance methodologies, reporting timelines, costs, and the program's cost/benefit analyses.

The program evaluation objectives will be to:

1. Assess participant satisfaction with the program;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy efficiency;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;
5. Assess the effectiveness of program delivery mechanisms.

7. TIMELINE

Action	Start	End
Program Approval	02/10	06/10
Implementation	06/10	12/12
Evaluation	01/12	06/12*

*Evaluation Report will be provided on 08/15/12

8. ANNUAL BUDGET

	Year 1	Year 2	Year 3
Customer Incentives	$ 24,500	$ 49,000	$ 49,000
Equipment/Vendor	$ 3,000	$ 6,000	$ 6,000
Promotion	$ 5,700	$ 12,000	$ 12,000
Evaluation	$ 2,000	$ 2,000	$ 6,000
TOTAL COSTS	$ 35,200	$ 69,000	$ 73,000

9. EXPECTED SAVINGS / BENEFITS

a. Anticipated load Impact Per Participant: (Based on 5 Ton Units)

Upgrading Heat Pump Customers:

Energy Savings Per Year	=	1,240 kWh
Demand Reduction	=	0.350 kW
		(@ system winter peak)
	=	0.164 kW
		(@ system summer peak)

b. Upgrading Air Conditioning Customers: (Based on 5 Ton Units)

Energy Savings Per Year	=	313 kWh
Demand Reduction	=	0.000 kW
		(@ system winter peak)
	=	0.164 kW
		(@ system summer peak)

c. Annual Expected Program Savings/Benefits (including T&D losses) @ 120 units in one year:

Winter Demand Reduction	Summer Demand Reduction	Annual Energy Savings
6.8 kW	19.6 kW	55 MWh

Projected energy savings and demand reductions are estimated based on the anticipated number of installations. The estimated effects of freeriders are included.

d. Projected Program MWh Savings and kW Reduction Assuming Participation (Including T&D losses):

Goal of 300 units is achieved (all customers in three years)

Energy Savings	=	137 MWh
Demand Reduction	=	17.4 kW
	(@ system winter peak)	
	=	49.1 kW
	(@ system summer peak)	

10. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on Summer Peak and the information available at the time of program design.

a.	Total Resource Cost	=	1.24
b.	Ratepayer Impact Measure	=	0.39
c.	Participant	=	1.68
d.	Utility Cost	=	1.02

HVAC Diagnostic and Tune-up Program

1. DESCRIPTION

Kentucky Power Company (KPCo), working with participating licensed HVAC dealers, will target residential and small commercial customers with HVAC system performance problems.

2. RATIONALE FOR PROGRAM

The objective of this program is to reduce energy use by conducting a diagnostic performance check on residential and small commercial unitary air conditioning and heat pump units, air restricted indoor and outdoor coils, and over and under refrigerant charge. Units determined to have one of these four problems will be eligible for corrective action.

Numerous HVAC systems with these maintenance requirements are marginally operational and the customer is unaware of the situation. These units experience longer run times resulting in excess energy consumption and demand, and reduced unit life. The resulting repairs will reduce energy usage and demand, improve customer comfort and extend the serviceable life of the unit.

3. PARTICIPATION GOALS

	Residential		Small Commercial	
	HP	CAC	HP	CAC
Jan. 2010 thru Dec. 2010	40	60	4	26
Jan. 2011 thru Dec. 2011	215	325	24	136
Jan. 2012 thru Dec. 2012	280	420	30	170

4. ELIGIBLE CUSTOMERS

Residential and small commercial customers (less than 100 kW) with unitary central air-conditioning or heat pump systems are eligible. The program is not designed for customers who seek repair of non-operational units. Those units are outside the scope of this program.

5. INCENTIVES

KPCo will offer residential and small commercial customers a $50.00 and $75.00, incentive respectively, for the diagnostic and tune-up service. Participating HVAC dealers will also receive a $50 incentive for promoting the program.

6. IMPLEMENTATION PLAN

A. Promotion

KPCo will develop relationships with HVAC dealers to promote the HVAC Tune-up program. Media advertising, such as newspaper, radio, television, and billboard, may also be used.

B. Delivery

KPCo representatives will work in conjunction with participating HVAC dealers to target residential and small commercial customers will probable HVAC system performance problems.

C. Quality Assurance

The program will be regularly reviewed by KPCo staff responsible for the program as well as the Company's DSM Collaborative. The Company will maintain communication with participating HVAC dealers as well as respond to any customer inquiries. A selected sample of the tune-ups performed will be inspected to assure corrective action is being performed properly and that resulting energy savings are being achieved.

D. Evaluation

KPCo will perform an evaluation relating to the program's impact and processes, including program objectives, data collection procedures, quality assurance methodologies, reporting timelines, costs, and the program's cost/benefit analyses.

The program evaluation objectives will be to:

1. Assess participant satisfaction with the program;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy efficiency;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;
5. Assess the effectiveness of program delivery mechanisms.

7. TIMELINE

Action	Start	End
Program Approval	02/10	06/10

Implementation	06/10	12/12
Evaluation	01/12	06/12*

* Evaluation report will be provided on 08/15/12.

8. **ANNUAL BUDGET**

a. Residential

	Year 1	Year 2	Year 3
Customer Incentive ($50/participant)	$ 5,000	$ 27,000	$ 35,000
Equipment/Vendor ($50/vendor)	$ 5,000	$ 27,000	$ 35,000
Promotion (Marketing)	$ 6,000	$ 6,000	$ 6,000
Administrative Costs	$ 700	$ 3,780	$ 4,900
Evaluation	$ 0	$ 0	$ 8,500
TOTAL COSTS	$ 16,700	$ 63,780	$ 89,400

b. Commercial

	Year 1	Year 2	Year 3
Customer Incentive ($75/participant)	$ 2,250	$ 12,000	$ 15,000
Equipment/Vendor ($50/vendor)	$ 1,500	$ 8,000	$ 10,000
Promotion (Marketing)	$ 3,000	$ 3,000	$ 3,000
Administrative Costs	$ 210	$ 1,120	$ 1,400
Evaluation	$ 0	$ 0	$ 3,200
TOTAL COSTS	$ 6,960	$ 24,120	$ 32,600

9. **EXPECTED SAVINGS / BENEFITS**

a. Anticipated load Impact Per Residential Participant:

Energy Savings Per Year (HP) = 741 kWh (Heating & Cooling)
(CAC) = 311 kWh (Cooling)
Demand Reduction = 0.219 kW (HP only)
(@ system winter peak)
= 0.169 kW (HP & CAC)
(@ system summer peak)

Anticipated load Impact Per Commercial Participant:

Energy Savings Per Year	(HP)	= 1,638 kWh (Heating & Cooling)
	(CAC)	= 687 kWh (Cooling)
Demand Reduction		= 0.507 kW (HP only) (@ system winter peak)
		= 0.357 kW (HP & CAC) (@ system summer peak)

b. Annual Expected Program Savings/Benefits (including T&D losses) @ 700 (540 Residential and 160 Sm. Commercial) units in the second year:

	Summer Peak Demand Reduction	Winter Peak Demand Reduction	Annual Energy Reduction
Residential	99 kW	52 kW	281 MWh
Sm.Comm.	63 kW	13 kW	143 MWh

Projected energy savings and demand reductions are estimated based on the anticipated number of installations. No free-riders are assumed.

c. Projected Program MWh Savings and kW Reduction Assuming Participation (Including T&D losses):

Goal of 1,340 Residential units and 390 Sm. Commercial units is achieved (all customers in three years)

Residential:	Energy Savings	= 699 MWh
	Demand Reduction	= 128 kW (@ system winter peak)
		= 249 kW (@ system summer peak)
Sm. Comm.	Energy Savings	= 349 MWh
	Demand Reduction	= 32 kW (@ system winter peak)
		= 153 kW (@ system summer peak)

10. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

			Residential	Commercial
a.	Total Resource Cost	=	1.15	1.51
b.	Ratepayer Impact Measure	=	0.29	0.35
c.	Participant	=	6.07	7.97
d.	Utility Cost	=	1.00	1.17

AEP
KENTUCKY POWER®
A unit of American Electric Power

Kentucky Power
P O Box 5190
101A Enterprise Drive
Frankfort, KY 40602
KentuckyPower.com

Jeff R. Derouen, Executive Director
Kentucky Public Service Commission
P. O. Box 615
211 Sower Boulevard
Frankfort, KY 40602

May 3, 2010

Dear Mr. Derouen:

Re: Case No. 2010-00198

In the Matter of the Joint Application Pursuant to 1994 House Bill No. 501 for the Approval of Kentucky Power Company Collaborative Demand-Side Management Programs, and for Authority to Recover Costs, Net Lost Revenues And Receive Incentives associated with the Implementation of one New Commercial and one combined Residential / Commercial Demand-Side Management program beginning August 2, 2010.

The Joint Applicants, with the exception of the Office of the Attorney General's representative who abstained, seek authority for Kentucky Power Company to implement one commercial and one combined residential / commercial DSM program to recover costs including net lost revenues and incentives related to those programs.

In this filing, the DSM Collaborative is requesting Commission approval of a new Commercial Incentive Program. The program is designed to address any cost-effective electricity saving measure not addressed or offered through other Kentucky Power Company (KPCo) Programs. Projects in the Commercial Incentive Program targets measures where the unit energy savings can be reliably predicted and therefore standard per-measure savings and incentive levels can be established. Specific savings and incentives for more complex systems or processes, most often requiring unique design and technology solutions for each participant, will be determined when the project is specified.

4. ELIGIBLE CUSTOMERS

All commercial customers are eligible to participate in this incentive program when they purchase qualifying equipment or services. Customers who do not own the facility (i.e., rent or lease) may participate in the program with the building owner's written consent. All projects must be pre-approved by KPCo prior to purchase or installation of any equipment or materials.

5. ELIGIBLE MEASURES

A listing of potential program measures to be delivered to commercial customers is summarized below. Energy efficiency measures may be added or subtracted based on recommendations of a third party program implementation contractor as selected through a competitive bidding process.

Lighting Measures

- Compact fluorescent lamps for indoor/outdoor (screw-in and pin-based fixtures)
- LED exit sign
- High-performance T8 lamps and fixtures (with electronic ballast) T12 to T8 conversion
- Standard T8 to reduced wattage T8 lamps
- T5 fluorescent lamps and fixtures (with electronic ballast)
- High-bay fluorescent lamps and/or fixtures to replace HID lamps
- *Pulse Start Metal Halide*
- Electronic dimming ballast
- Delamping with reflectors (combined with T8 ballast retrofit)
- Occupancy sensors
- LED Traffic Signals
- Cold cathode lamps

HVAC Measures

- High efficiency packaged HVAC equipment
- Addition of an economizer
- Programmable thermostat
- Reflective window film

Motors and Drive Measures

- NEMA Premium® motors
- Adding electronic adjustable speed drive to fans and pumps (variable frequency drives under 200 hp controlled)

For the Custom portion of this program, potential eligible measures will vary given the need to respond to custom applications, and may include measures such as:

- Process
- Refrigeration
- Compressed Air
- Controls
- Retrocommissioning
- Cool Roofs

6. INCENTIVES

Incentives under this program will be provided to customers at the lesser of (1) the calculated incentive level, as described below, or (2) up to 50% of the incremental equipment cost, those costs above federal and/or state standard efficiency levels, of qualifying energy efficient products. Incentive levels will be finalized based on proposals received from a program implementation contractor selected through a competitive bidding process. However, incentives for each portion of this program are defined in general terms below:

Prescriptive Measures

KPCo will work with the selected third party implementation contractor to define appropriate incentive levels for each qualifying energy efficiency measure. This will provide customers with a known incentive funding for each qualifying measure and will streamline the process of processing customer applications and provide KPCo with the ability to further pursue energy efficiency at the highest levels. Incentives under the Prescriptive portion of this program are estimated to be in the range of 8 cents per kWh of the estimated annual kWh savings expected from the project, on average, or as suggested by the selected third party contractor and will be provided to the customer as a one-time incentive payment.

Custom Measures

The selected third party implementation contractor will assist KPCo with the review, analysis, and verification of estimated energy savings associated with energy efficiency measures not included in the prescriptive portion of this program. Many of these projects will require in-depth engineering calculations, and KPCo will rely on the experience, expertise, and advice of the third party implementation contractor when deriving these projected savings. Incentives under the Custom portion of this program are estimated to be in the range of 8 cents per kWh of the estimated annual kWh savings expected from the project, on average, or as suggested by the selected third party contractor and will be provided to the customer as a one-time incentive payment.

Direct Install

KPCo may also implement, based on customer response to the program, a direct install option. This strategy will target those small businesses that typically do not have easy access to energy efficiency programs. For example, these businesses usually have limited access to the capital needed to perform energy efficiency upgrades and, at the same time, have other business projects competing for limited capital. The incentives for a direct install strategy are typically higher than those included in standard prescriptive-type programs. However, these higher incentives are necessary to encourage those customers to move toward higher energy efficiency levels. As reference, of KPCo's approximately 29,000 commercial and public authority accounts, approximately 93% of those have a peak demand of 50kW or less. KPCo will work with the selected third party program implementation contractor to determine the viability of a direct install strategy for KPCo's small business customers as well as other rules and requirements.

To ensure cost effectiveness, KPCo suggests that the minimum project simple payback must be greater than one year and the maximum project simple payback can be no greater than the life of the equipment and / or 10 years. If multiple projects are completed by a customer in a single calendar year, the incentives will be prioritized based on payback. The total incentive paid per project can not exceed $20,000 annually. However, KPCo may revise the payback range and/or the maximum incentive per project based upon program implementation contractor recommendations and/or overall customer response to the program. Custom measures will be evaluated on a case by case basis.

7. IMPLEMENTATION PLAN

Delivery of the Commercial Incentive Program will be achieved through the combined efforts of KPCo account managers and customer services account representatives, and a program implementation contractor hired through a competitive bidding process.

KPCo staff and the program implementation contractor will work to generate awareness of the Commercial Incentive Program among customers and market providers of energy efficiency services and equipment. The objective of the outreach activities is to identify and develop custom projects for further analysis.

Outreach by the KPCO account managers and customer services account representatives will be emphasized in the early stages of the program to expedite previously identified potential for projects that have been stalled. Greater emphasis will be placed on generating energy efficiency service provider referrals in 2011 and beyond to expand participation and reduce costs as the KPCo network of program allies grows.

KPCo and the program implementation contractor will work with customers and market providers to identify and pre-qualify prospective projects. This may involve completing custom engineering calculations that assess the energy saving potential, payback, project eligibility, and incentive amount. The customer must submit a pre-application before the project start-up.

If the project is approved by the program implementation contractor, the customer will receive an approval letter describing the terms for acceptance of the project. The customer has a limited time (30 days) to sign the acceptance offer to reserve incentive funding. Upon customer signature of the incentive offer, the program implementation contractor will schedule a pre-installation inspection with the customer to capture pre-work conditions. The customer has a limited time period (6 months) to complete the project to be eligible for reimbursement, or request a limited time extension.

Once projects are completed, the program implementation contractor will assist the customer to verify the installation to ensure program integrity before issuing payment. Post installation inspections and documentation review must be completed by the program implementation contractor to insure the project is operating as intended. The inspection and documentation review may result in modifications to claimed savings and incentive amount. The program implementation contractor will submit final incentive claims to KPCo for payment. KPCo has the option to perform a random sample of post installation inspections to verify the services performed at customer premises and to determine the customer's satisfaction with the project.

8. EVALUATION

A. Goals

KPCo will perform an evaluation assessing and documenting the program's processes and estimating the program's impacts as well as performing a benefit/cost analysis from data collected by the program implementation contractor on the various program measures installed.

B. Objectives

The program evaluation objectives are to:

1. Assess participant satisfaction with energy efficient technologies of measures installed, the service performed by the contractors, marketing representatives, and the program as a whole;

2. Assess the effectiveness of the program delivery mechanism, including the efficiency of program operation and marketing efforts;

3. Gain insight into market potential, including the participant and non-participant characteristics, participation rate, and customer awareness;

4. Determine the program load impact, including the energy savings and demand reduction, measure persistence, snap-back effect, and free ridership; and

5. Assess program cost-effectiveness based on the standard economic tests.

9. TIMELINE

Action	Start	End
Program Approval	04/10	08/10
Implementation	08/10	12/12
Evaluation	08/10	06/12*

* Evaluation report will be provided on 08/15/12.

10. ANNUAL BUDGET

	Year 1	Year 2	Year 3
Contractor Administration*	$ 98,450	$ 236,268	$ 461,796
Customer Incentives*	$ 44,748	$ 562,544	$ 1,099,517
Promotion	$ 25,000	$ 60,000	$ 98,960
Program Evaluation	$ 8,000	$ 37,340	$ 68,210
TOTAL COSTS	$ 176,198	$ 896,152	$ 1,728,483

*Projected contractor administration / incentive costs are based on "Request for Budgetary Information" obtained from Franklin Energy Services and KEMA Services, Inc. Projected Promotion / Evaluation Costs are based on the best information available at the time of program design as determined by KPCo and KEMA Services.

11. EXPECTED SAVINGS / BENEFITS

Year	Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
2010	47	82	392
2011	596	1,034	4,929
2012	1,165	2,021	9,635

Projected energy savings and demand reductions are estimated based on the anticipated number of installations of various types of energy-efficient measures installed in commercial buildings. The estimated effects of T & D losses are included. Freeriders are included.

The projected annual program effects at the end of the three-year period are an energy savings of 14,956 MWh and peak winter and summer demand reductions of 3,137 kW and 1,808 kW, respectively.

12. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

a. Total Resource Cost = 3.41

b. Ratepayer Impact Measure = 0.71

c. Participant = 8.50

d. Utility Cost = 2.39

Pilot
Residential and Small Commercial Load Management Program

1. DESCRIPTION

The objective of this pilot program is to determine whether peak demand can be effectively reduced through the installation of load control devices on residential and small commercial central air-conditioners, heat pumps and/or electric water heaters. Load reduction is accomplished by reducing the duty cycle of air conditioning equipment and turning off water heaters during peak periods.

2. RATIONALE FOR PROGRAM

Load management of central air-conditioning, heat pumps and water heaters has become a widely used strategy of electric utilities across the country to reduce peak demand and thereby lower costs and delay future generating requirements. Such programs are normally effective since they target some of the main drivers of the summer / winter peak. The Company plans to have the capability to control devices for up to 150 hours per year at a maximum duty cycling of 6 consecutive hours.

3. PARTICIPATION GOALS

A total of 1,000 residential customers and 100 small commercial customers are desired to accomplish the program goals for the pilot three year program (2010 – 2012). The Company projects the installation of load control devices as described below:

Residential Goals

Year	Switches - A/C	Switches - Water Heaters	Total Switches
2010	25	25	50
2011	475	475	950
2012	500	500	1,000

Commercial Goals

Year	Switches - A/C	Switches - Water Heaters	Total Switches
2010	10	10	20
2011	45	45	90
2012	45	45	90

4. ELIGIBLE CUSTOMERS

Residential and small commercial customers taking retail electric service from KPCo with qualifying central air-conditioning, heat pump and/or electric water heating equipment will be eligible to participate in the program. Customers who do not own the residence or facility (i.e., rent or lease) may participate in the program with the building owner's written consent.

5. INCENTIVES

KPCo will provide incentives to residential and small commercial who allow KPCo to install, own, operate and maintain a load cycling switch on the customer's qualifying central air-conditioning, heat pump and/or electric water heating equipment. The incentive will be structured as follows:

A residential customer with central air-conditioning will receive $20 per year ($5 per summer months, June, July, August, and September) for each air-conditioning or heat pump unit participating in the program. Small commercial customers will also receive $20 per year ($5 per summer months, June, July, August, and September). Residential and small commercial customers with a qualifying electric water heater will receive an additional $8 per year ($1 per summer & winter months, June, July, August, September, November, December, January and February), per unit to participate. In the areas where necessary communication infrastructure is not readily available, the program will not be available to those customers.

5. IMPLEMENTATION PLAN

A. Promotion

KPCo will promote the program to potential customers by direct contact, electronic or USPS mail notice, or other expeditious means. Customers will sign a participation agreement with KPCo to properly document customer approval.

B. Delivery

The customer will allow KPCo access to the residence/building to install the required devices, test communication with KPCo, and instruct the customer in the proper handling and purpose of the load cycling device.

C. Quality Assurance

KPCo reserves the right to inspect the equipment to ensure that it remains in proper operating order.

D. Evaluation

KPCo will perform an evaluation relating to the program's impact and processes, including program objectives, data collection procedures, quality assurance methodologies, reporting timelines, costs, and the program's cost/benefit analyses.

The program evaluation objectives will be to:

1. Assess participant satisfaction with the program;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy efficiency;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;
5. Assess the effectiveness of program delivery mechanisms.

6. TIMELINE

Action	Start	End
Program Approval	04/10	08/10
Implementation	08/10	12/12
Evaluation	08/10	06/12*

*An Evaluation Report will be provided to the Public Service Commission on or before August 15, 2012, which will be based on 2011 program impacts.

7. ANNUAL BUDGET

Residential

	Year 1	Year 2	Year 3
Administrative	$115,305	$ 230,610	$ 230,610
Promotion	$ 15,000	$ 35,000	$ 35,000
Equipment	$ 9,300	$ 176,700	$ 186,000
Equipment Installation	$ 3,275	$ 62,225	$ 65,500
Switch Maintenance	$ 250	$ 4,780	$ 5,030
Incentives	$ 75	$ 14,000	$ 28,000
Evaluation	$ 6,200	$ 29,460	$ 29,750
TOTAL COSTS	$149,405	$ 552,775	$ 579,890

Commercial

	Year 1	Year 2	Year 3
Administrative	$ 12,810	$ 25,625	$ 25,625
Promotion	$ 1,000	$ 3,000	$ 3,000
Equipment	$ 4,690	$ 21,105	$ 21,105
Equipment Installation	$ 1,320	$ 5,940	$ 5,940
Switch Maintenance	$ 120	$ 540	$ 540
Incentives	$ 30	$ 1,540	$ 2,800
Evaluation	$ 1,000	$ 2,890	$ 2,950
TOTAL COSTS	$ 20,970	$ 60,640	$ 61,960

8. EXPECTED SAVINGS / BENEFITS

One of the purposes of this pilot program is to collect the actual energy and demand savings from the use of load control devices applied to residential / small commercial central air-conditioners, heat pumps and / or electric-water heaters. The results of the actual savings and the actual costs will be used to determine the cost-effectiveness of the program. KPCo will need to have enough load data at a minimum for a full winter season and full summer season in order to prepare a complete analysis of the program. If the program is approved according to the schedule outlined in the TIMELINE noted above, a full evaluation report is planned to be completed at the latest during the first half of 2012.

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 10, lines 2 to 22

a. Please describe, in detail, the "current environmental permits" applied to the boiler that "limit the Plant's possible fuel options", and how a new boiler would mitigate those concerns.

b. Please describe, in detail, the "physical limitations of the boiler" that "limit the Plant's possible fuel options."

c. Please provide any analyses performed by or for the Company on the expected life of the existing boiler.

d. Are there other end-of-life or maintenance issues that prevent the current boiler from being utilized in future years up to the expected life of the plant?

e. Please provide the annual price of coal delivered to Big Sandy from 2000 through 2012, inclusive, and the average sulfur content of that coal.

f. Please list KPC's long-term coal contracts, and details of the contracts, including the length of contract, source of coal, heat and sulfur content of the coal, and the expected annual cost (in $/ton, nominal or real [specify]) of the coal over the term of the contract.

RESPONSE

a. KPCo is not proposing a new boiler be installed, only to be modified. Current environmental permits do not limit the boiler"s operation. The testimony was in error in this respect.

b. See response to Staff 1-46 for a general list and discussion of modifications needed to I ncrease fuel flexibility.

c. There is no analysis of the expected life of the existing boiler.

d. There are no end-of-life or maintenance issues that are expected to prevent the boiler from being utilized in future years.

e. See Attachment 1 to this response for the requested information regarding the delivered price of coal for the Big Sandy Plant. Note that the annual delivered price and sulfur content of coal is not yet available for 2012.

f. See Attachment 2 to this response for the requested information regarding KPCo long-term coal contracts effective as of 1-16-2012.

WITNESS: Robert L Walton

Year	Average of lbsSO2/mmBtu	Average of Delivered Fuel Price $/ton excluding zeros
2000	1.52	$24.42
2001	1.55	$28.24
2002	1.56	$26.76
2003	1.63	$28.88
2004	1.58	$43.12
2005	1.51	$49.30
2006	1.43	$48.88
2007	1.38	$48.23
2008	1.40	$61.94
2009	1.45	$58.04
2010	1.45	$61.15
2011	1.45	$70.09

The data in the table above was gathered using Ventyx Velocity Suite software. The source of this data is the Energy Information Agency Form 923 (EIA-923). This form was formerly the Federal Energy Regulatory Commission Form 423 (FERC-423).

Vendor	Contract Number	Delivery Start Date	Delivery End Date	Coal Source	Heat Content (BTU/lb)	Sulfur Content (lb SO2/MMBTU)	Price per Ton ($/Ton, by Year)	
Arch Coal Sales Company, Inc. (FOB Mine)	03-30-07-901	1/2/2007	12/31/2012	KY	12,300	1.80[1]	2007	$48.00
							2008	$48.75
							2009	$50.75
							2010	$52.75
							2011	$58.75
							2012	$77.50
Argus Energy, LLC (FOB Plant)	03-30-07-903	1/1/2007	12/31/2012	KY, WV	12,000	1.75	2007	$51.75
							2008	$52.75
							2009	$54.50
							2010	$56.00
							2011	$57.40
							2012	$82.65
Beech Fork Processing, Inc. (FOB Plant)	03-30-08-901	10/1/2008	12/31/2013	KY	12,000	1.60	2008	$82.00
							2009	$79.00
							2010	$74.00
							2011	$72.29
							2012	$72.29
							2013	$80.00
Cliffs Logan County Coal, LLC (FOB Mine)	03-30-08-900	5/1/2008	12/31/2012	WV	12,500	1.20	2008	$70.00
							2009	$70.00
							2010	$72.00
							2011	$72.00
							2012	$72.00
Rhino Energy, LLC (FOB Plant)	03-30-10-900	10/1/2010	12/31/2013	WV	12,000	1.60	2010	$73.00
							2011	$69.75
							2012	$75.50
							2013	$78.45
S. M. & J., Inc. (FOB Plant)	03-30-10-901	1/1/2011	12/31/2013	KY	12,000	1.60	All	$78.15
Trinity Coal Marketing LLC[3] (FOB Mine)	03-30-07-905	1/1/2008	12/31/2012	KY, WV	12,500	1.60	2008	$47.00
							2009	$49.00
							2010	$50.50
							2011	$52.50
							2012	$54.50

1 - for 2008 the Arch contract could deliver up to 1.90 # SO2/MMBTU coal. All other years required 1.80 # SO2/MMBTU

2 - Price Reopener based on indices for 2012.

3 - Price under Trinity contract is FOB mine. Add $6.00/ton for truck delivery to plant and $9.50/ton FOB barge

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, pages 14 and 15.

a. Please identify the generally accepted accounting principles that apply to the determination of the time period over which the Company depreciates major capital investments, such as the capital cost of a FGD.

b. Please identify the time period over which the Company would propose to depreciate the cost of the FGD unit according to those generally accepted accounting principles and in the absence of any material risk of future environmental regulations.

c. Please identify cases in which the Public Service Commission of Kentucky has approved a 15 year time period for depreciation of a FGD.

d. Please identify cases in which the Public Service Commission of Kentucky has approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

e. Please identify cases in which the regulatory commissions in other states in which American Electric Power operates have approved a 15 year time period for depreciation of a FGD.

f. Please identify cases in which the which the regulatory commissions in other states in which AEP operates have approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

g. Please list the "increased EPA standards" that could cause operation of this unit not to be economically feasible in the future.

h. Please describe how the Company analyzed the risk associated with those "increased EPA standards" in its economic evaluation of resource alternatives.

i. Please explain how the Company would bear a portion of the risk of stranded investment if the Commission approves recovery through the environmental cost recovery surcharge, and describe the percent of the risk the Company would bear.

j. Please explain, with supporting illustrative calculations, how a 15 year depreciation period would reduce the risk of stranded investment that ratepayers will bear if the Commission approves recovery through the environmental cost recovery surcharge.

RESPONSE

a. The Generally Accepted Accounting Principle (GAAP) that applies to the determination of the time period over which the Company depreciates its investment is the matching principle. The matching principle requires that the asset's cost be allocated to depreciation expense over the life of the asset.

FASB 71 states that if a regulator prescribes a period of time to depreciate an asset that is shorter than the useful life of the asset then using the shorter life is consistent with GAAP.

b. The Company is not proposing a period other than the 15 years since is does not believe it is appropriate to assume an absence of any material risk of future environmental regulations. As stated in response to Staff 1-12, the expected life could reach 70 years and thus the depreciation life would be 25 years.

c. The Company is not aware of any cases in which the KPSC approved a 15 year time period for depreciation of a FGD.

d. The Company is not aware of any cases in which the KPSC approved a shorter time period to recover depreciation in order to reduce the risk of stranded investment.

e. The Company is not aware of any other regulatory commission in other states in which American Electric Power operates has approved a 15 year time period for depreciation of a FGD.

f. In Indiana & Michigan's CPCN filing for a scrubber on one of its Rockport Units in Cause No. 43636, they are asking for a 15 year depreciation period. Please see Attachment 1 to this response as the statutory authority to ask for this time frame..

g. The Company does not know what those future increased EPA standards will be at this time.

h. The Company did not attempt to analyze the risk associated with future unknown increased EPA standards.

i. The Company proposes to make the investment to provide service to its customers at the lowest cost and in accordance with federal law. Under these circumstances the Company should not bear any risk of stranded investment.

j. Attachment 2 to this response is an illustrative calculation comparing the depreciation of an asset over 15 years versus 25 years. You will notice that at the end of 15 years the asset being depreciated over 25 years still has $370M of undepreciated plant (net plant). If the Company were to retire that asset in year 15 (before the end of the 25 year depreciation period), the $370M of net plant is stranded investment. If the asset were to be retired prior to 15 years, both scenarios would have stranded investment, but the asset being depreciated over 15 years would have less stranded investment versus the asset being depreciated over 25 years. Thus, the amount at risk subject to stranded investment is much less.

WITNESS: Ranie K. Wohnhas

LexisNexis®

1 of 1 DOCUMENT

BURNS INDIANA STATUTES ANNOTATED

Statutes current through Act PL 231 of the 2011 First Regular Session
Annotations current through June 28, 2011 for Indiana Supreme Court cases, through June 22, 2011 for Indiana Appellate Court cases, through May 27, 2011 for Indiana Tax Court cases, and through July 8, 2011 for Federal Court cases.

Title 8 Utilities and Transportation
Article 1 Public Utilities
Chapter 2 Indiana Utility Regulatory Commission
[Valuation and Accounting]

Go to the Indiana Code Archive Directory

Burns Ind. Code Ann. § 8-1-2-6.7 (2011)

8-1-2-6.7. Clean coal technology -- Depreciation.

(a) As used in this section, "clean coal technology" means a technology (including precombustion treatment of coal):

(1) That is used in a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and

(2) That either:

(A) Is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or

(B) Has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989.

(b) The commission shall allow a public or municipally owned electric utility that incorporates clean coal technology to depreciate that technology over a period of not less than ten (10) years or the useful economic life of the technology, whichever is less and not more than twenty (20) years if it finds that the facility where the clean coal technology is employed:

(1) Utilizes and will continue to utilize (as its primary fuel source) Indiana coal; or

(2) Is justified, because of economic considerations or governmental requirements, in utilizing non-Indiana coal;

after the technology is in place.

HISTORY: P.L.105-1989, § 3.

NOTES:

LexisNexis 50 State Surveys, Legislation & Regulations

Coal Processing & Power Generation

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Gross Plant	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940										
Depreciation (6.667%)	63	63	63	63	63	63	63	63	63	63	63	63	63	63	63										
Accum. Deprec.	63	126	189	252	315	378	441	504	567	630	693	756	819	882	945										
Net Plant	877	814	751	688	625	562	499	436	373	310	247	184	121	58	-5										
Gross Plant	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940	940
Depreciation (4%)	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Accum. Deprec.	38	76	114	152	190	228	266	304	342	380	418	456	494	532	570	608	646	684	722	760	798	836	874	912	950
Net Plant	902	864	826	788	750	712	674	636	598	560	522	484	446	408	370	332	294	256	218	180	142	104	66	28	-10

Note 1 - Figures are in millions

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, pages 14 and 15.

a. Does the Company expect to recover the net plant balance of Big Sandy Unit 2 from ratepayers at whichever point in time Unit 2 is retired? If yes, what is the basis for the Company position?

b. What is the projected net plant balance of Big Sandy Unit 2 as of January 1, 2015?

c. What is the expected salvage value of Big Sandy Unit 2 as of January 1, 2015 and what is the basis for that estimate?

RESPONSE

a. Yes, the Company expects full recovery on all of its investments made at any of its plants.

b. While Kentucky Power's projections of net plant in service are not available by generating unit, they are available at a functional level (e.g. generation, transmission, and distribution). The projected functional net plant balances as of January 1, 2015 are as follows:

KPCo as of 1-1-2015	NP in $000s
Steam Production	273,883
Production GSU's	886
Transmission	316,195
Distribution	507,373
General	23,775
Intangible	1,888
Total Net Plant	1,124,000

c. The last demolition study for Big Sandy was completed in 2005 and estimated salvage value at $250,000. No newer projections have been made at this time.

Please see Attachment 1 for the last demolition study completed for Big Sandy.

WITNESS: Ranie K Wohnhas

Table of Contents

American Electric Power Company
Big Sandy Power
LOUISA, KY

Dismantling Information **June 1, 2005**

BIG SANDY AEP POWER PLANT
CONCEPTUAL DEMOLITION PLAN

DEFINITIONS:

RACM **(estimated 3,000 cubic yards)**
Regulated Asbestos Containing Material as defined in 40 CFR 61, Subpart M and any other applicable Federal, State, and/or Local rules, regulations and/or ordinances.

Concrete Debris
Concrete stacks, cooling towers, and floor slabs (estimated 35,000 cubic yards)

onstruction / Demolition Debris
Any solid waste resulting from the construction, remodeling, repair, or demolition of structures. Such wastes may include, but not limited to;
roof material/drywall/ceiling tiles/fiberglass (estimated 3,500 yards)
brick (estimated 6,500 yards)
railroad ties (estimated 30,650 ties)

Contractor
The individual, partnership or corporation with which AEP Company enters into a contract to perform all of the work described in the Specification.

Contract
A purchase order placed by Purchaser and accepted by Contractor, together with this Specification and all other documents referred to in such purchase order, or a formal contract executed by Purchaser and Contractor, together with this Specification and all other documents referred to in such formal contract.

Engineer
The Engineer or his authorized representative designated by AEP Company to be assigned to this contract.

Fill Material
Material to be used to bring area to grade.

Greases
Any used or unused greases or waste containing grease.

Hazardous Waste
Hazardous waste as defined in 40 CFR 261.3 or as defined in any applicable state regulation.

HAZMATs

Any hazardous, toxic or regulated substance controlled under RCRA, CERCLA or any other Federal, State, or Local law, statute, regulation or ordinance pertaining to the handling, transportation, or disposal of any controlled substance.

Landfill

River City Disposal
1837 River Cities Drive
Ashland, KY 41102

MSDS

Material Safety Data Sheet.

Non-Ferrous Scrap (estimated 290,000 lbs)

All non-ferrous scrap such as copper or brass (estimated 290,000 lbs).

Oils (estimated 50,000 gallons)

Any used or unused hydraulic, lubrication, rolling, waste or other such oil or oily waste.

OSHA

Occupational Safety and Health Act and amendments thereto.

PCBs

Polychlorinated By-phenols (plant personnel verified that there are no PCB's present at the site).

Process Materials

Any raw materials, blended raw materials, recyclable process generated dusts (such as flue dust), fly ash, ash slurry and etc.

SCR Unit

Selective Catalytic Reduction Unit

Scrap Ferrous (estimated 22,000 tons)

All ferrous scrap designated by the Engineer to be suitable for melting at a steel processing plant.

Structural Removal

As in the Specification, shall mean all work of every nature described herein, implied herein, or necessary to complete the work described or implied herein, with the exception of Asbestos Abatement.

AEP Company

American Electric Power Company

American Electric Power Company
Big Sandy Power
LOUISA, KY

Information Sheets

Dismantling Information **June 1, 2005**

BIG SANDY POWER

1. GENERAL SCOPE OF WORK

1.1. The work to be performed under the terms of this specification shall consist of the dismantling and removal of all facilities, machinery, equipment, all associated structures, foundations, debris, asbestos containing materials, hazardous substances and hazardous waste as directed by the Engineer. Upon completion each dismantling site shall be left in a neat, clean, safe condition.

1.2. Work under this specification shall be performed in accordance with the terms and conditions of the Contract, entered into between AEP Company and the Contractor, and in accordance with all EPA, OSHA, Federal, State, County, and Local laws, statutes, ordinances, and regulations.

1.3. The Contractor shall perform all utility disconnection and/or relocation work which is necessary to complete the proposed dismantling and removal work, without disrupting active utilities.

1.4. The Contractor shall perform all excavation, back-filling, construction and closure work which is necessary to complete the proposed dismantling work.

1.5. The Contractor shall provide all labor, materials, equipment, services and pay all necessary taxes, in addition to securing all required permits, to perform the dismantling.

1.6. The Contractor is responsible to clean up and dispose of any and all materials which are generated as a result of a spill caused by the Contractor, or which are generated as a result of the improper handling of any materials by the Contractor. This includes all RACM, Hazardous Substances, Hazardous Waste, Special wastes, Non-process Debris, Demolition Debris, and combustible materials.

2. FACILITY DISMANTLEMENT AND RELATED WORK

2.1. Perform the environment abatement of the following:

2.1.1. Vacuum, transport and dispose of dust accumulations inside area of Unit 1 Boiler

2.1.2. HAZMAT sweep of structures, tanks and pipe in Unit 1 Boiler area

2.1.3. Abate tank insulation in Unit 1 Boiler along with all connected pipes

2.1.4. Abate Unit 1 Boiler, boiler breeching and piping

2.1.5. Abate Unit 1 Boiler building siding, office and turbine building siding, Unit 1 coil conveyor, Unit 1 coil conveyor transfer building, Unit 1 train coal unload station house and miscellaneous outside structures.

2.1.6. Remove Units 1 fluorescent light bulbs, PCB ballast, mercury vapor light, HID vapor lights and mercury containing instruments.

2.1.7. Vacuum, transport and dispose of dust accumulations inside area of Unit 2 Boiler

2.1.8. HAZMAT sweep of structures, tanks and pipe in Unit 2 Boiler area

2.1.9. Abate tank insulation in Unit 2 Boiler along with all connected pipes

2.1.10. Abate Unit 2 Boiler, boiler breeching and piping

2.1.11. Abate Unit 2 miscellaneous outside structures.

2.1.12. Remove Unit 2 fluorescent light bulbs, PCB ballast, mercury vapor light, HID vapor lights and mercury containing instruments.

2.1.13. Remove office, storage and maintenance building fluorescent light bulbs, PCB ballast, mercury vapor light, HID vapor lights and mercury containing instruments.

2.1.14. Remove the secondary and primary river water pump house building fluorescent light bulbs, PCB ballast, mercury vapor light, HID vapor lights and mercury containing instruments.

2.2. Perform the building dismantling, equipment removal, concrete removal to surrounding grade elevation of the following.

2.2.1. Unit 1 boiler building, turbine generator building, precipitators, office and maintenance building, coal conveyor.

2.2.2. Unit 2 boiler building, turbine generator building, precipitators, office and maintenance building the chemical lab building, coal conveyor to Unit 2 coal pile, the SCR building and the Unit 1 & 2 concrete smoke stack.

2.3. Perform the removal of the following to grade elevation.

2.3.1. Unit 1 water cooling tower structure, adjacent pump structures, adjacent condensate water tank to surround grade elevation. Fill the pits and trenches to surround grade elevation.

2.3.2. The pump house and metal cleaning waste treatment tank located west of Unit 1 boiler building.

2.3.3. The coal train car unload building, adjacent control building, the coal conveyor and coal transfer and sampling building.

2.3.4. The tractor shed and locomotive house building.

2.3.5. The remains of the standby river water make-up equipment, railroad ties and pipes to the Big Sandy River.

2.3.6. The in-service sanitary treatment equipment, trenches and tanks located adjacent to the Big Sandy River.

2.3.7. The secondary and primary river water pump building structures, the two electrical control buildings. Remove building and water intakes to surrounding grade elevation. Install a barricade in the water inlet from the Big Sandy River. Remove the water inlet screens from the river.

2.3.8. The ammonia storage building and chemical manufacturing building structure and ammonia storage tank structures.

2.3.9. The 500,000 gallon fuel oil tank and oil pump station. Remove the oil tank dike down to surround grade elevation.

2.3.10. The six single story maintenance, storage and office buildings located south of the Unit 2 boiler building.

2.3.11. The Unit 2 water cooling tower structure, adjacent pump structures, adjacent clean condensate water tank, dirty condensate water tank, the fire water control building, the sulfuric acid storage and control building, the chlorine tank and control building to surround grade elevation. Fill the pits and trenches to surround grade elevation.

2.3.12. The Unit 2 coal conveyor from the coil pile to the Unit 2 boiler.

2.3.13. The coal train unload building, coal conveyor from the unload building to the coal transfer building to the coal storage area. Remove all bents and transfer building to surround grade elevation. Remove the coal truck unload equipment from grade elevation to the bottom of the pit. Fill the truck unload pit and the coal train unload pit to surrounding grade elevation. Fill the pit from the coal train station to the coal conveyor exit with fill material to surround grade elevation.

2.3.14. The coal system sample building, trailer and sample equipment to surrounding grade elevation.

2.3.15. The coal system transportation office and maintenance building located east of the coal storage area.

2.3.16. The two truck scales, control building, and coal train car warming structure and equipment down to surrounding grade elevation.

2.3.17. The abandoned 3,400,000 gallon fuel storage tank. Remove the dike wall surrounding the fuel tank to surrounding grade elevation. Remove all pumps, pipe, wires, and controls from the tank area to the Unit 2 boiler structure.

2.3.18. Remove the maintenance parts storage building located north of the Unit 2 turbine building.

2.3.19. Remove the electrical wire, and electric towers from the transformers located adjacent to Unit 2 boiler building to the 345,000 volt electrical station located north of Highway 23.

2.3.20. Remove the electrical wires and electrical tower from the transformers located adjacent to Unit 1 boiler building to the 134,000 volt electrical station. Remove the four step-down transformers and connections between the 134,000 volt switch yard and the block building. Remove the block building down to surrounding grade elevation.

3. WORK BY CONTRACTOR

The Contractor Shall:

3.1. Furnish all supervision, labor, materials, tools, supplies and equipment necessary to perform the work, including dismantling and removal of all the facilities, equipment, structures, etc. noted herein with the exception of specific structures which are designated in this Specification to remain.

3.2. Furnish on the site, during the performance of the work, an experienced supervisor who shall be duly authorized to represent and act for the Contractor in all matters pertaining to the work covered by this Specification.

3.3. Provide all written instructions, orders, and other communications delivered to the Contractor's construction office shall be considered as having been delivered to the Contractor himself.

3.4. Develop detailed written demolition plans for each area to be dismantled, and submit them to the Engineer for his review prior to the start of work in an area. Such plans shall include, but limited to:

3.4.1. A detailed and complete schedule for the performance of the work.

3.4.2. A survey of each area, identifying all materials to be disposed of other than scrap and equipment.

3.4.3. Identification and protection of demolition areas.

3.4.4. Termination and/or relocation of utilities.

3.4.5. Asbestos abatement and disposal.

3.4.6. Handling and disposal of hazardous wastes and materials.

3.4.7. Handling and disposal of oils and greases.

3.4.8. Handling and disposal of non-hazardous debris and materials.

3.4.9. Handling and disposal of ODC's.

3.4.10. Fire prevention and protection.

3.4.11. Handling and storage locations for ferrous and non-ferrous scrap.

3.4.12. Method of demolition and/or equipment removal.

3.4.13. Clean-out, breaking open, and filling of basements, pits, and tunnels.

3.4.14. Final grading and restoration of demolition site.

3.5. Clear each site of existing equipment, structures, and material designated to be removed. Each site will be left in a neat, clean, safe condition in conformity with all applicable Federal, State, or Local laws, statutes and/or regulations, including but not limited to CAA, OSHA, RCRA, SARA, TSCA, and/or CERCLA. The finished condition of each site will be approved by the Engineer.

3.6. Remove all structures down to final grade except where otherwise noted. Final grade will generally be the adjacent grade surrounding the facility to be removed. The removal of concrete & debris and grading will be done concurrent with the demolition work. As one area is cleared of structures, the required concrete removal work in that area will be done simultaneously with the demolition of structures in the next area of work. If the Contractor breaches the provisions of this section AEP Company reserves the right, in AEP Company's sole opinion, to stop the Contractor from doing further demolition until the concrete and debris removal is current.

3.7. Perform all material removal and asbestos abatement work in accordance with all applicable Federal, State, and/or Local rules, regulations and/or ordinances, which is necessary to complete the proposed removal work.

3.8. Perform all utility, telecommunications and telemetering disconnection and/or relocation work which is necessary to complete the proposed removal work.

3.9. Prior to beginning demolition of any facility, Contractor shall ascertain that no live utilities remain in the facility and identify and locate all underground utilities. It shall be the Contractor's exclusive responsibility to determine that all utility systems in each area remain isolated from active utility systems.

3.10. Perform all excavation, back–filling, construction and closure work which is necessary to complete the proposed dismantling and removal work.

3.11. Remove all debris generated as a result of the proposed removal work.

3.12. Break the floors of all pits, trenches and depressions sufficiently to provide drainage and to prevent the accumulation of water within the underground structure.

3.13. Tunnel and basement roof structures which do not support structures designated to remain and which are located less than 3 feet below finish grade elevation will be broken in. Said tunnel excavations will be filled with fill materials approved by the Site Engineer up to finish grade elevation.

3.14. Properly drain and capture all contents of pipelines prior to dismantling any pipelines.

3.15. Empty and shovel clean all pits, sumps, basements, and depressions to the satisfaction of the Engineer. Areas will be inspected by the Site Engineer prior to filling. Any pits, sumps, basements or depressions in contact with a hazardous waste or PCB shall be decontaminated in accordance with any applicable Federal and/or State rules and/or regulations.

3.16. Back-fill all pits, sumps, and depressions up to existing grade. Each site shall be rough graded and left in a neat, clean, safe condition. Contractor will use fill material approved by the Engineer. The final six inches of fill shall be other select fill material approved by the Engineer.

3.17. Furnish all fill material in accordance with the Specification. If the work activity generates more fill material than needed, the Contractor shall pay for the transportation and disposal off site. If the work activity is fill negative, the Contractor shall pay for the purchase and transportation of required fill to the site. Such purchased material shall be approved by the Site Engineer.

3.18. Furnish portable sanitary facilities and drinking water for Contractor's personnel in areas of removal.

3.19. Furnish electric power and temporary lighting in those areas of removal where active utilities are not available.

3.20. Provide adequate protective barriers for open pits, holes and depressions, as a result of the equipment removal work, until they are properly backfilled. Temporary barricades shall conform to all applicable Federal, State and Local, rules and regulations or standards including, but not limited to OSHA.

3.21. Remove above ground utility support systems such as poles, structural steel towers or guy wires which have been designated to be removed by the Engineer.

3.22. Remove and scrap all tanks, including supporting steel and concrete structures. Prior to removal work Contractor shall remove the contents of each tank, drain each tank and otherwise purge each tank in accordance with all applicable rules or regulations to render them safe for removal. Notify Engineer of any potentially contaminated soils. Remove of these tanks shall conform to all applicable Federal, State, and Local laws, statutes, regulations or ordinances.

3.23. Secure the approval of local Fire Department for the Fire Prevention Plan. Contractor shall meet with representatives of the Fire Department prior to commencement of work on each facility. Prior to the commencement of removal work, Contractor shall inspect all fire hydrants in the work area and shall notify the Engineer of those that are not in good operating condition.

3.24. Provide fire extinguishers and fire hoses as required to immediately control any fires resulting from the work. Implement all fire prevention measures as directed by the Fire Department. Measures required by Fire Department may include, but will not be limited to, the maintenance of pressurized fire hoses at each removal site.

3.25. Attend a safety meeting with AEP Company's representatives prior to starting work in each facility or designed area.

3.26. Furnish all temporary or permanent supports or protective devices which are necessary to preserve active pipes, electrical lines or other structures which AEP Company designates to remain in place.

3.27. Abide by AEP Company Contractor Safety Responsibilities, AEP Company Energy Control-Lockout and Tryout Rules, as well as all Federal, State, and Local regulations.

3.28. Secure the Engineer's approval prior to using any railroad track or mobile crane movements to or from the dismantling site.

3.29. Schedule rail movements, order all railroad cars and be solely responsible for demurrage charges resulting from the Contractor's operations.

3.30. Where Contractor removes railroad track, the Contractor shall remove all wooden and concrete ties, and load and transport them to an approved disposal site approved by the Engineer. Contractor shall be responsible for the cost of all removal, loading, transportation, and disposal of such material.

3.31. ACM ABATEMENT

3.31.1. Contractor shall provide all supervision, labor, consumable materials, tools, equipment, documentation, services and permits required to identify, remove, and dispose of all ACM located on, in, adjacent to or forming a part of each structure designated for removal. RACM removal work shall include but is not necessarily limited to the work described herein.

3.31.2. Prepare a complete, written ACM removal plan for each dismantling site. Contractor shall obtain and analyze all bulk sample analyses of any suspect RACM. Prior to the commencement of work, Contractor shall provide the Engineer with the results of the analyses and Contractor's removal plan.

3.31.3. Provide all respirators, protective clothing and equipment required to protect all personnel associated with the RACM removal work. All respirators, protective clothing and equipment shall conform to all applicable rules, regulations, and standards, including but not limited to OSHA..

3.31.4. Employ only competent persons, trained, knowledgeable and qualified in the techniques of abatement, handling and disposal of RACM and subsequent cleaning of contaminated areas. Employees who perform RACM removal work shall posses current, valid asbestos abatement licenses as required by any governmental agency having jurisdiction over the work.

3.31.5. Perform all RACM removal in strict accordance with all applicable Federal, State, and Local laws, statutes, ordinances and regulations. Contractor shall provide timely and accurate notification in accordance with all Federal, State, and Local laws, statutes, and regulations and ordinances.

3.31.6. Adequately wet all friable RACM prior to removal. Adequately wet RACM debris shall be packaged in bags provided by Contractor. Bags of ACM debris shall promptly placed in dumpster boxes provided by Contractor.

3.31.7. Haul all RACM debris from each RACM removal site to the disposal site approved by AEP Company. Contractor shall unload RACM at the disposal site. All transportation of RACM shall be performed in enclosed dumpster boxes.

3.31.8. Be responsible for any spilling, escape or release of RACM which occurs during the transportation of RACM to the disposal site. AEP Company shall be responsible for any spilling, escape or release of RACM which occurs after the RACM has been unloaded by Contractor at the disposal site approved by AEP Company. Contractor shall immediately report to AEP Company any spilling, escape or release of RACM which occurs during the transportation of RACM. Contractor shall submit copies of reports of spilling, escape or release of RACM to all authorities as required by Federal, State or Local laws, statutes, regulations and ordinances.

3.31.9. Maintain complete and accurate records of all removal, transportation and disposal activities in accordance with all Federal, State and Local laws, statutes, regulations and ordinances. Contractor shall submit copies of all such records to AEP Company on a daily basis.

3.31.10. Perform personal and area air monitoring as necessary to assure the safety of all persons associated with the removal of ACM and as required by Federal, State and Local laws, statutes, regulations and ordinances. Contractor shall perform environmental air monitoring in the area at each location where RACM removal work is performed. Environmental air monitoring shall conform to all applicable Federal, State, and Local laws, statutes, regulations and ordinances.

3.32. HAZARDOUS WASTE HANDLING AND DISPOSAL

3.32.1. Contractor shall provide all supervision, labor, consumable materials, tools, equipment, documentation, services and permits required to identify, remove and load any hazardous waste located in, adjacent to or forming a part of the equipment designated for removal. Contractor shall be responsible to perform all in-plant handling of such materials, including, but not limited to removal, loading, and in-plant transportation. Hazardous waste removal work shall include, but is not necessarily limited to, the work described herein.

3.32.2. Contractor is required to secure samples of all materials, which are suspected of being a hazardous waste, located in the areas defined in this Specification. Samples shall be collected in accordance with all applicable regulations. Contractor shall deliver all samples of suspected hazardous waste to the Engineer. AEP Company shall secure required analyses of all such samples.

3.32.3. Prepare a complete written hazardous waste removal plan for each work site that will be submitted to the Engineer for his review prior to the start of work in an area.

3.32.4. Contractor shall provide all respirators, protective clothing and equipment required to protect all personnel associated with the handling or removal of any Hazardous Wastes. All said respirators, protective clothing and equipment shall conform to all applicable rules, regulations and standards, including but not limited to OSHA.

3.32.5. Employ only competent persons, trained, knowledgeable and qualified in the techniques of handling and disposal of hazardous wastes and subsequent cleaning of contaminated areas. Employees who perform hazardous waste removal work shall possess current, valid licenses as required by any government agency having jurisdiction over the work. Perform all hazardous waste removal in strict accordance with all applicable Federal, State and Local laws, statutes, ordinances and regulations. Contractor shall provide timely and accurate notification in accordance with all Federal, State and Local laws, statutes, regulations and ordinances.

3.32.6. Contractor shall post all appropriate warning signs at each work area, as is required by applicable regulations.

3.32.7. Maintain complete and accurate records of all removal activities in accordance with all Federal, State, and Local laws, statutes, regulations and ordinances. Contractor shall submit copies of all such records to AEP Company on a weekly basis.

3.32.8. Perform personal monitoring as necessary to assure the safety of all persons associated with the removal of hazardous wastes and as required by Federal, State, and Local laws, statutes, regulations and ordinances. If so required, Contractor shall perform environmental air monitoring in the area of each location where hazardous waste removal work is performed. Environmental air monitoring shall comply with applicable Federal, State, and Local laws, statutes, regulations and ordinances.

3.32.9. AEP Company shall be responsible for disposal, the method of disposal and the disposal site for all identified hazardous waste except asbestos waste. Contractor shall load all such wastes into trucks or containers provided by AEP Company.

3.33. CONSTRUCTION / DEMOLITION WASTE

3.33.1. Contractor is required to perform the work described herein in a manner that will separate construction / demolition waste from ferrous scrap, combustible waste, non-ferrous scrap, ferrous scrap, process demolition waste, oils and greases, hazardous wastes, and all other materials.

3.33.2. Contractor shall identify all quantities of construction / demolition waste to the Engineer. The Engineer shall positively identify all such materials as being construction / demolition waste.

3.33.3. For all materials which have been positively identified by the Engineer as construction / demolition waste, Contractor shall use such materials as clean fill in locations approved for filling by the Engineer.

3.33.4. Contractor shall be responsible to perform all in-plant handling of such materials, including, but not limited to, screening, separation, from other materials, loading, crushing and transportation.

3.33.5. Contractor shall be responsible for any costs that are incurred as a result of his handling construction / demolition waste, including, but not limited to, sampling, analysis, permit applications, loading, on and off-site transportation, and disposal at an approved disposal site.

3.34. OILS

3.34.1. Contractor is required to secure samples of all oils and oily wastes located in the areas defined in this Specification. Samples shall be collected in accordance with all applicable regulations.

3.34.2. AEP Company shall secure analyses required by the applicable regulations, or by the disposal facility, of all such samples, including, but not limited to, analysis for PCB contamination.

3.34.3. For all oils which have been positively identified as being free of PCB contamination (i.e. less than 50 ppm), Contractor shall be responsible to perform all handling of such materials, including, but not limited to, removal, clean up, loading and transportation.

3.34.4. Contractor shall be responsible to pay for fees to dispose of all oils and oily waste in accordance with all applicable regulations. The Engineer shall approve all methods of disposal and disposal sites for all oils and oily waste.

3.35. GREASES

3.35.1. Contractor is required to secure samples of all greases and wastes containing grease located in the areas defined in this Specification. Samples shall be collected in accordance with all applicable regulations.

3.35.2. AEP Company shall secure analyses required by the applicable regulations, or by the disposal facility, of all such samples.

3.35.3. Contractor shall be responsible to perform all handling of such materials, including, but not limited to, removal, clean up, loading, and transportation.

3.35.4. AEP Company shall be responsible for the disposal of all special and hazardous greases and waste containing greases in accordance with all applicable regulations.

3.36. PROCESS MATERIALS

3.36.1. Contractor is required to perform the work described herein in a manner that will separate process demolition debris from ferrous scrap, combustible debris, non-ferrous scrap, construction / demolition waste, oils and greases, hazardous wastes, and all other materials.

3.36.2. Prior to the start of demolition in an area, Contractor shall identify all quantities of process materials to the Engineer. The Engineer shall positively identify all such materials as being process materials.

3.36.3. All ash process materials will remain on-site. A two foot clay cap will be utilized to cap process material areas of concern.

3.37. PCBs AND EQUIPMENT CONTAINING PCBs

3.37.1. Prior to dismantling, Contractor shall conduct a survey of each dismantling area to locate and identify any electrical or hydraulic equipment which has not been clearly identified as being free of PCB contamination and, therefore, may contain PCBs. Contractor shall provide the Engineer with the location and description of any surveyed equipment which may contain PCBs. Where so directed by AEP Company, Contractor shall provide AEP Company with a sample of the oil contained in the piece of equipment. AEP Company will secure analysis and provide Contractor with the written results.

3.37.2. Prior to dismantling the facility, the Contractor shall remove, intact each piece of PCB contaminated equipment. Contractor shall transport said PCB equipment to AEP Company's designated PCB storage facility. Contractor shall schedule and coordinate said deliveries with the Engineer. Alternatively, at the direction of the Engineer, Contractor shall load PCB equipment onto vehicles provided by AEP Company. Contractor shall schedule and coordinate said loading with the Engineer. Contractor shall schedule and coordinate the pumping and removal of PCB dielectric fluid from transformers prior to loading when so directed by the Engineer.

3.37.3. AEP Company shall be responsible for the disposal of all PCB equipment and fluids.

3.38. PIPING SYSTEMS

3.38.1. Prior to the commencement of dismantling work, Contractor shall identify, plan and perform all piping shut offs, disconnections, and relocation work necessary to complete the work specified in a safe, orderly manner.

3.38.2. Piping shall be purged (where necessary) and shall be removed to a point of origin as designated by the Engineer.

3.38.3. Contractor shall submit plans, procedures and working drawings showing design details for all piping work to the Engineer for review. Contractor shall secure the Engineer's review of all designs, plans and procedures prior to the commencement of work. The correctness of the design shall remain the Contractors responsibility.

3.38.4. Contractor shall provide all supervision, labor, materials, tools and equipment necessary to complete all piping work required for the work as specified herein. Contractor shall be responsible for the identification of all piping construction, disconnection and relocation work which will be required to complete all work specified herein.

3.38.5. Contractor shall perform all piping construction, disconnection and relocation work using methods which will not interrupt AEP Company's ongoing operations.

3.38.6. Secure the Engineer's permission prior to any utility outage. In the absence of the Engineer's approval of Contractor's proposed outage, Contractor shall perform the proposed work on live pressurized lines.

3.39. ELECTRICAL SYSTEMS

3.39.1. Prior to the commencement of dismantling work, Contractor shall identify, plan and perform all electrical shut offs, disconnections, and relocation work necessary to complete the work specified in a safe and orderly manner.

3.39.2. Conduit, cable, wireways, and buss shall be removed to a point of origin as designated by the Engineer.

3.39.3. Contractor shall submit plans, procedures and working drawings showing design details for all electrical and related work to the Engineer for review. Contractor shall secure the Engineer's review of all designs prior to the commencement of work. The correctness of design shall remain the Contractor's responsibility.

3.39.4. Contractor shall provide all supervision, labor, materials, tools and equipment necessary to complete all electrical, telecommunication and telemetering work required for the dismantling work specified herein. Contractor shall be responsible for the identification of all electrical, telecommunication and telemetering construction, disconnection and relocation work which will be required to complete all work specified herein.

3.39.5. Contractor shall perform all electrical construction, disconnection and relocation work using methods which will not interrupt AEP Company's ongoing operations.

3.39.6. Contractor shall secure the Engineer's permission prior to any utility outage. In the absence of the Engineer's approval of Contractor's proposed outage, Contractor shall perform the proposed work on live energized lines.

4. WORK BY PURCHASER:

AEP Company Shall:

4.1. Provide Material Safety Data Sheets (MSDS) in accordance with OSHA "Right to Know" regulations for each substance listed under said regulations.

4.2. Provide, where available, utility services such as 460 Volt, 3 phase, 60 Hz power, 250 Volt DC current, potable water, oxygen, compressed air, or natural gas, which are deemed available by AEP Company. Contractor may, at his own expense and approval of the Engineer, make necessary connections provided there is no interruption to normal production operations. AEP Company assumes no responsibility or liability for loss of, or damage to, the equipment or materials of the Contractor or his subcontractors. Contractor will pay charges that may be assessed. The assessment of charges and/or the availability of utilities may change through the course of the contract as determined.

4.3. Provide existing railroad tracks, railroad tracks sidings, and roadways on plant site, if available, for Contractor's use when and where the Engineer may designate. Contractor shall keep traffic lanes free of congestion so as to avoid interference with normal plant operations.

4.4. Provide one copy of all available drawings necessary for the completion of the work specified. These drawings are to be used by the Contractor for reference only in the performance of the work. Said drawings are not to be construed as a complete description of the Scope of Work, nor as fully depicting existing conditions. Additional copies may be purchased by Contractor through the Purchaser.

4.5. Approve the selection of all subcontractors before they will be allowed to enter the job site and perform work. Subcontractors are subject to all applicable terms and conditions contained herein.

4.6. Provide written releases for the demolition of each specific area or facility as identified in the Schedule of Values. Demolition shall not commence without the receipt of said release.

4.7. Assign to Contractor ownership of each facility to be dismantled. The assignment shall include:

4.7.1. All ferrous and non-ferrous scrap resulting from the dismantling work

4.7.2. All ferrous and non-ferrous scrap located within each dismantling area as identified by Engineer during the site visitation.

4.7.3. Spare parts and/or spare equipment.

4.7.4. All railroad track designated for removal.

4.7.5. All vehicles and mobile equipment located within each dismantling area as identified in the Specification.

4.8. AEP Company will maintain ownership of all real estate

5. Pricing

5.1. Demolition and environmental abatement of Unit 1, 2, structures, equipment, cooling towers, stacks, buildings, railroad tracks and tanks
$12,000,000

5.2. Removal of piping, dewatering and capping of bottom and slurry ash ponds
$20,000,000

Assumptions

This estimate is based on all roadways, concrete slabs, and foundations remaining in place.

This estimate is based on AEP providing an on-site clay source for the capping of the ash ponds.

This estimate is based on treating and disposal of all water to either the ground or into the river system.

This estimate is based on dewatering 150 acres at 3 feet deep.

This estimate is based on capping a 150 acre site.

This estimate does not include any survey work to establish grades.

This estimate is based on preserving all storm water sewers to the Big Sandy River.

This estimate is based on saving the two electrical sub-stations located on the AEP property.

This estimate is based on disposing all concrete and brick material at the ash slurry ponds.

This proposal does not include any PCB oil and/or equipment disposal.

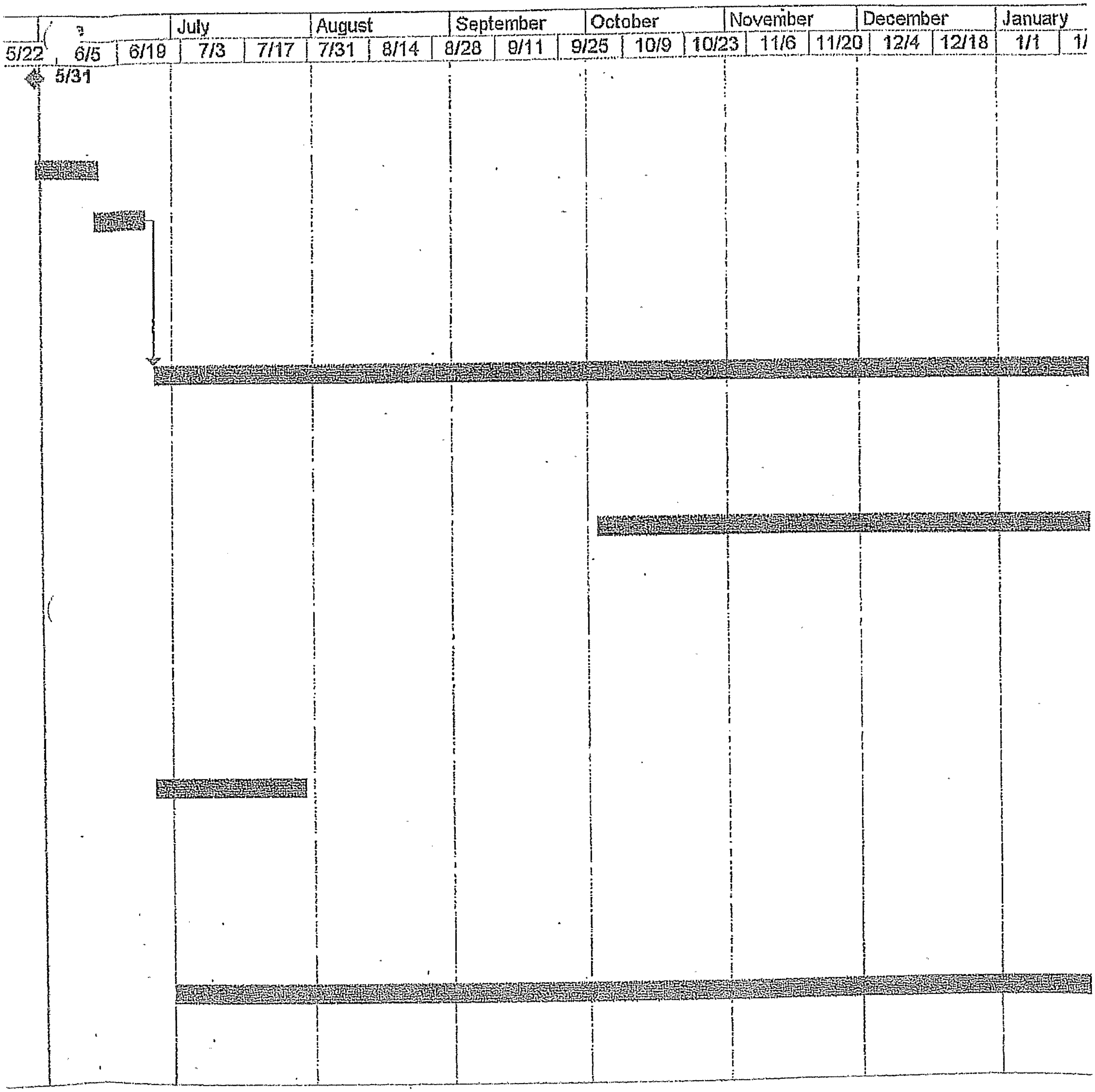
This proposal is based on Brandenburg receiving ownership of all ferrous and non-ferrous scrap.

This proposal does not include any site security.

This proposal is based on Pittsburgh ferrous and non-ferrous pricing from the December 29, 2004 American Metal Market publication minus transportation and preparation.

AEP Company
Big Sandy River Power Plant
Louisa, Kentucky

ID		Text1	Task Name	Duration	Start	Jun 5/22
1		General Conditions		0 days	Tue 5/31/05	5/
2			meetings	10 days	Tue 5/31/05	
3			mobilization	10 days	Mon 6/13/05	
4			demobilization	10 days	Mon 8/6/07	
5						
6		Unit 1	environmental abatement	150 days	Mon 6/27/05	
7			demolition	40 days	Mon 1/23/06	
8						
9		Unit 2	environmental abatement	175 days	Mon 10/3/05	
10			demolition	50 days	Mon 6/5/06	
11						
12		SCR	demolition	20 days	Mon 7/10/06	
13						
14		Support Bldgs	demolition	25 days	Mon 6/27/05	
15						
16		Stack & Cooling Towers	demolition	120 days	Mon 8/7/06	
17						
18		Slurry Ash/Bottom Ash Pits	dewater	260 days	Fri 7/1/05	
19			grade/place cap	220 days	Mon 10/2/06	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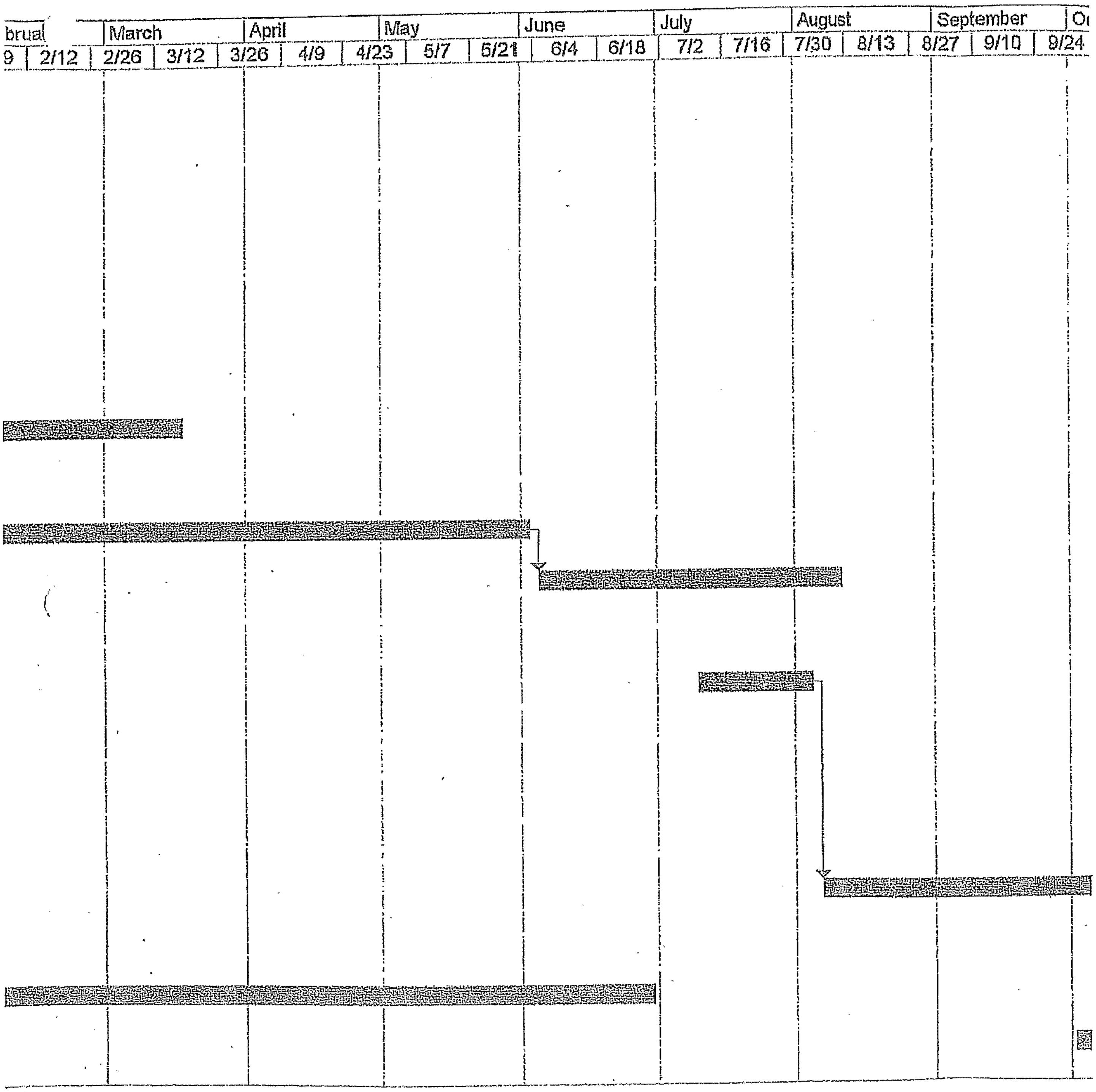
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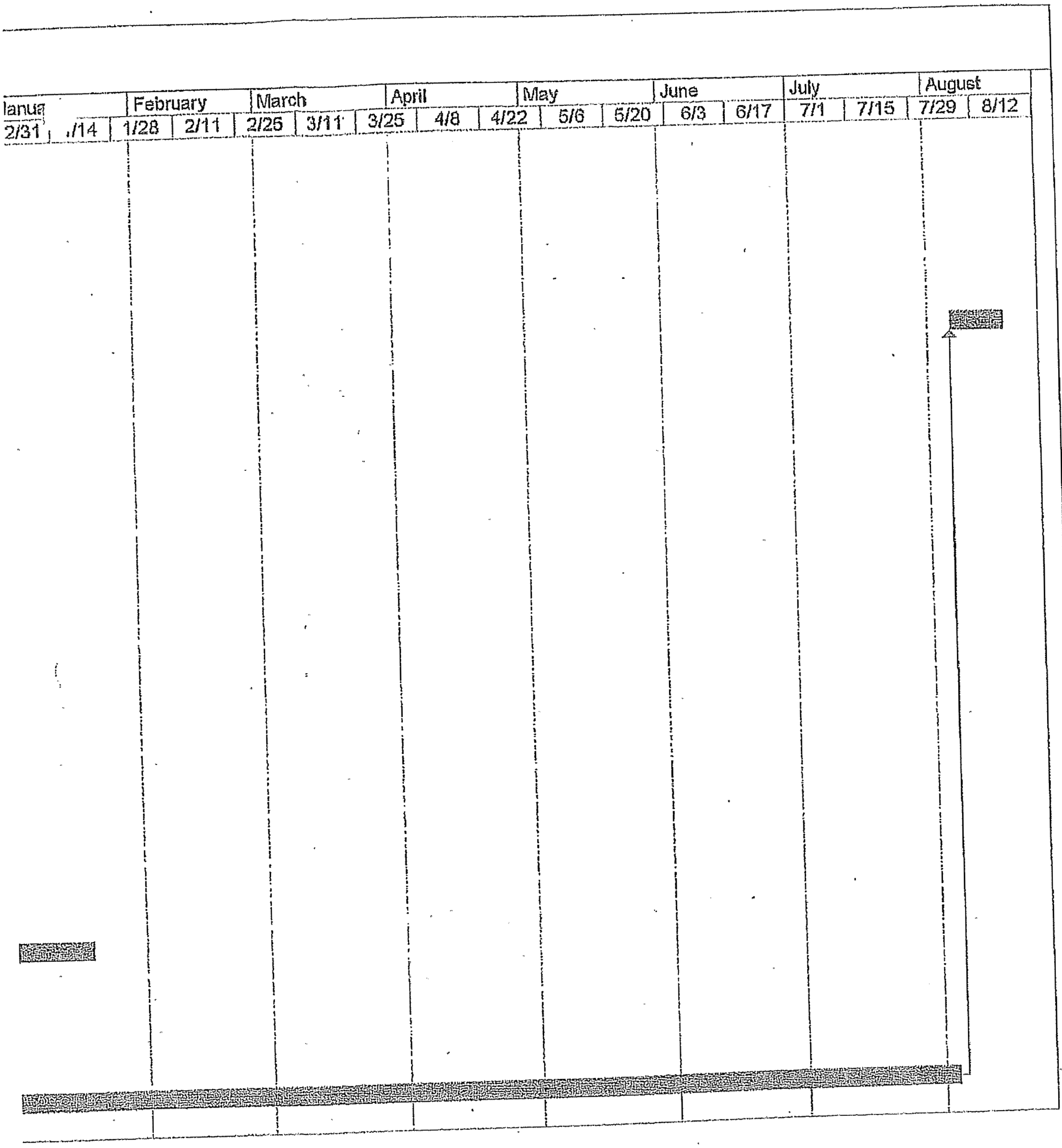
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Brandenburg® Industrial Service Company
1680 John A. Papalas Drive
Lincoln Park, Michigan 48146-1462
Phone (313) 382-2500
FAX (313) 382-4373
www.ibrandenburg.com

Brandenburg®

Methodology

General Project Consistent Activities

The following details Brandenburg's methodology in order to complete the scope of work safely and in a cost effective manner for the decontamination and demolition of the AEP Big Sandy Power Plant.

Mobilization will include bringing equipment on-site, set-up of hydraulic excavators, loaders, unloading of manlifts, bobcats, portable decontamination trailer, job tool and supply box, and the job office/break box.

Brandenburg will conduct a utility verification walk through on each building and/or work area in order to substantiate that all utilities servicing the removal area have been cut, capped, and / or air-gapped prior to proceeding with the removal efforts. During this verification, the color coding of all structures, buildings and tanks will also be verified as painted green and ready for removal. This task will be followed by environmental work including; gathering, staging and packaging of any loose chemicals and/or oils remaining in the buildings, removal of light bulbs and ballasts and followed by asbestos abatement. Once these tasks are complete, Brandenburg will perform a final walk through and complete a facility assessment report that signs off that the utility disconnection/isolation work, the environmental decommissioning and abatement work are complete and the building or structure is ready for demolition. Brandenburg will request the AEP representative to verify this facility assessment and sign the assessment form that concurrence is given to perform the demolition. Brandenburg will install geo-textile fabric over catch basins and / or sewer inlets within the demolition areas scheduled to remain in order to keep material from flowing into the existing system during the removal efforts. Following this preparatory work, the buildings and structures will be demolished.

Work specific to each Building or Structure is discussed below.

Boiler Units 1 and 2

Barricades consisting of snow fence and caution or danger tape will be placed at entry areas of the building to limit access into the building. Barricade tags obtained through the AEP representative will be complete and attached to the barricade fencing at points of egress.

Brandenburg crews will next "sweep" the units looking for loose chemical containers and remove, stage and package the materials to ready them for disposal. All light bulbs, light ballasts, and self-illuminating exit signs will then be taken down, packaged and staged. Brandenburg crews will access the lights within the units off of A-frame step ladders, lights and ballasts will be carefully removed by hand and through the use of small hand tools as necessary. Manlifts may be used if lights or other regulated materials are present at elevations higher than safely accessible with the ladders. Generally the crew will work in pairs with one person working on the ladder and a ground person retrieving the bulb or ballast after removal to place in a storage container.

Brandenburg shall utilize trained Kentucky licensed asbestos abatement personnel to perform asbestos remediation throughout the structures. Brandenburg shall conform to all state and federal regulations during the abatement efforts.

Brandenburg® Industrial Service Company
1680 John A. Papalas Drive
Lincoln Park, Michigan 48146-1462
Phone (313) 382-2500
FAX (313) 382-4373

General Practices

Regulated Areas

All Class I, II asbestos work will be conducted within regulated areas.
Access to the regulated area shall be limited to authorized persons.

Demarcation

Warning signs that demarcate the regulated area will be provided and displayed at each location where a regulated area is required to be established. The warning signs shall bear the following information: Danger, Asbestos, Cancer and Lung Disease Hazard, Authorized Personnel Only, Respirators and Protection Clothing Are Required In This Area.

Respiratory Selection

Brandenburg will provide at no cost to the employee the appropriate respirator as specified in Table 1 paragraph (h)(2)(iii), (iv),(v)-(h)(4)(ii) of 29 CFR 1926.1101 and maintain a respirator program in accordance with 1910.134(b), (d), (e), and (f).
Brandenburg will ensure that the employee uses the respirator as provided below.

During all Class I work.
During all Class II work where ACM is not removed in a "substantially intact state".
During all Class II work which is not performed using wet methods.
During Class II work where a "negative exposure assessment" has not been prepared.
During any work where exposure occurs above the PEL or excursion limit.

Brandenburg will provide and require the use of an approved half-face air purifying respirator for Class II jobs where a negative exposure assessment has not been performed.

Protective Clothing

Brandenburg will provide and require the use of protective clothing, such as Tyvek coveralls, head coverings, gloves and foot coverings for all employees performing abatement activities. The competent person will examine work suits worn by employees at least once per work shift for rips or tears that may occur during performance of work and will mend or replace work suits immediately if needed

Hygiene Facilities and Practices

Will be provided and performed as required in section (j) of 29 CFR 1926.110.

Engineering Controls

HEPA vacuums will be used as needed.
Wet methods will be used.
Prompt clean up and disposal of waste in leak tight containers.
Local exhaust ventilation equipped with HEPA filters as needed.
Enclosures will be used whenever feasible.

Specific Removal

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Thermal System Insulation:

The TSI identified in the facility are the asbestos containing pipe runs, breaching, boiler insulation and tank insulation. Sections of the pipe wrap will be glove bagged to remove the asbestos insulation and expose the pipe surface. Glove bag removal will continue along the pipe runs either continuously until complete or at approximately spacing of 8-feet between glove bags. The pipe runs between the glove bagged areas will be wetted and double wrapped with 6-mill poly-sheeting and duct taped and sealed at the ends to the pipe. Once wrapped and sealed, individual sections of the pipe will be secured with ropes, the pipe torch cut and lowered to the ground. Ground men will then move the pipe to the lined and sealed roll-off box for storage. A containment using the power house existing structure will erected to abate the boiler breaching, boiler insulation and tank insulation. ACM will be wetted, immediately double bagged and placed into roll off containers for disposal.

Vinyl Asbestos Tile and Mastic

Brandenburg shall remove asbestos containing floor tile within sealed critical areas by way of hand scrapers to "pop up" each tile. The tile removal will use wet methods during the removal work. Mastic associated with the removal of asbestos floor tile shall be accomplished utilizing a chemical adhesive remover. Said adhesive remover shall be collected, loaded, and transported to the landfill for disposal.

Window & Door Caulk

Prior to razing the structures, Brandenburg will remove windows containing asbestos caulk from the building. The windows will be wrapped in polyethylene sheeting and placed in a roll-off box for disposal as non friable asbestos. Brandenburg will then remove any remaining caulk from the structure using hand labor. Any removed window caulk will be placed in the roll off box with the windows. Polyethylene sheeting will be placed on the ground beneath all caulk removal work. Any caulk collected on the poly will be bagged and placed in the non friable asbestos roll off box. All work will be conducted using wet methods.

Transite Panels & Fire Doors

Brandenburg shall remove transite panels and fire doors by utilizing asbestos laborers to remove the panels intact. If necessary, man-lifts may be utilized to access the panels for removal. The panels and fire doors will be removed intact, wrapped in polyethylene sheeting, loaded in a lined roll-off box, and hauled to landfill for disposal.

Ceiling tiles

Ceiling tiles will be located within the building and critical areas sealed. The ceiling tiles will be removed by accessing the ceiling working off of A-frame ladders. The individual tiles will be wetted and removed intact. The removed tiles will be placed into 6-mil polyethylene asbestos

Brandenburg® Industrial Service Company
1680 John A. Papalas Drive
Lincoln Park, Michigan 48146-1462
Phone (313) 382-2500
FAX (313) 382-4373

bags. When the tile removal is complete the bags will be removed from the building and placed in a sealed and lined roll-off box for transport to the landfill for disposal.

Roofing Materials

The roofing materials identified in the survey will be removed as part of the demolition of the building. The roof will be wetted with water from fire hoses during the demolition process. Once the roofing materials are pulled to the ground the material will be loaded into Brandenburg trucks for transporting to the landfill as C&D waste material.

Following, the removal of all regulated materials, Brandenburg will prepare for the demolition.

Brandenburg will use a hydraulic excavators equipped with a grapple or shear in order to raze the existing structure in a controlled manner. The building structure will be wetted with a fire hose throughout the demolition effort to control dust emissions. The building debris (C&D) will be placed in a stock pile as the building is being demolished. As the material accumulates it will be loaded via a CAT 980 wheel loader into a Brandenburg trailer and transported to the landfill for disposal. Each load will have a separate bill of lading or manifest associated with the load. These tickets will be kept in the log book at the Brandenburg office area and a concurrent log will be completed to track out going waste volumes.

The basement floor slabs will be cracked for drainage and filled. Existing grade will be determined at the perimeter of the existing structure. Removal of above grade concrete will be accomplished with the excavator equipped with a bucket, concrete processor or hydraulic breaker. Continued misting of the work area with water will be performed to control dust emissions.

Scrap steel shall be segregated, loaded, and hauled off site to a steel recycler.

Brandenburg will utilize onsite concrete as backfill material for the area affected by the removal efforts. Backfill shall be placed and rough graded to the top of the elevation of the surrounding grade.

Office/Support Buildings

Brandenburg crews will next "sweep" the building looking for loose chemical containers and remove, stage and package the materials to ready them for disposal. All light bulbs, light ballasts, and self-illuminating exit signs will then be taken down, packaged and staged. Brandenburg crews will access the lights within the building off of A-frame step ladders, lights and ballasts will be carefully removed by hand and through the use of small hand tools as necessary. Generally the crew will work in pairs with one person working on the ladder and a ground person retrieving the bulb or ballast after removal to place in a storage container.

Brandenburg shall utilize trained Kentucky licensed asbestos abatement personnel to perform asbestos remediation throughout the structures. Brandenburg shall conform to all state and federal regulations during the abatement efforts.

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General Practices

Regulated Areas

All Class I, II asbestos work will be conducted within regulated areas.
Access to the regulated area shall be limited to authorized persons.

Demarcation

Warning signs that demarcate the regulated area will be provided and displayed at each location where a regulated area is required to be established. The warning signs shall bear the following information: Danger, Asbestos, Cancer and Lung Disease Hazard, Authorized Personnel Only, Respirators and Protection Clothing Are Required In This Area.

Respiratory Selection

Brandenburg will provide at no cost to the employee the appropriate respirator as specified in Table 1 paragraph (h)(2)(iii), (iv),(v)-(h)(4)(ii) of 29 CFR 1926.1101 and maintain a respirator program in accordance with 1910.134(b), (d), (e), and (f).
Brandenburg will ensure that the employee uses the respirator as provided below.

During all Class I work.
During all Class II work where ACM is not removed in a "substantially intact state".
During all Class II work which is not performed using wet methods.
During Class II work where a "negative exposure assessment" has not been prepared.
During any work where exposure occurs above the PEL or excursion limit.

Brandenburg will provide and require the use of an approved half-face air purifying respirator for Class II jobs where a negative exposure assessment has not been performed.

Protective Clothing

Brandenburg will provide and require the use of protective clothing, such as Tyvek coveralls, head coverings, gloves and foot coverings for all employees performing abatement activities. The competent person will examine work suits worn by employees at least once per work shift for rips or tears that may occur during performance of work and will mend or replace work suits immediately if needed

Hygiene Facilities and Practices

Will be provided and performed as required in section (j) of 29 CFR 1926.110.

Engineering Controls

HEPA vacuums will be used as needed.
Wet methods will be used.
Prompt clean up and disposal of waste in leak tight containers.
Local exhaust ventilation equipped with HEPA filters as needed.
Enclosures will be used whenever feasible.

Specific Removal

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Thermal system Insulation:

The TSI identified in the facility are the asbestos containing pipe runs. Sections of the pipe wrap will be glove bagged to remove the asbestos insulation and expose the pipe surface. Glove bag removal will continue along the pipe runs either continuously until complete or at approximately spacing of 8-feet between glove bags. The pipe runs between the glove bagged areas will wetted and then double wrapped with 6-mill poly-sheeting and duct taped and sealed at the ends to the pipe. Once wrapped and sealed, individual sections of the pipe will be secured with ropes, the pipe torch cut and lowered to the ground. Ground men will then move the pipe to the lined and sealed roll-off box for storage.

Vinyl Asbestos Tile and Mastic

Brandenburg shall remove asbestos containing floor tile within sealed critical areas by way of hand scrapers to "pop up" each tile. The tile removal will use wet methods during the removal work. Mastic associated with the removal of asbestos floor tile shall be accomplished utilizing a chemical adhesive remover. Said adhesive remover shall be collected, loaded, and transported to the landfill for disposal.

Window & Door Caulk

Prior to razing the structures, Brandenburg will remove windows containing asbestos caulk from the building. The windows will be wrapped in polyethylene sheeting and placed in a roll-off box for disposal as non friable asbestos. Brandenburg will then remove any remaining caulk from the structure using hand labor. Any removed window caulk will be placed in the roll off box with the windows. Polyethylene sheeting will be placed on the ground beneath all caulk removal work. Any caulk collected on the poly will be bagged and placed in the non friable asbestos roll off box. All work will be conducted using wet methods.

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Ceiling tiles

Ceiling tiles will be located within the building and critical areas sealed. The ceiling tiles will be removed by accessing the ceiling working off of A-frame ladders. The individual tiles will be wetted and removed intact. The removed tiles will be placed into 6-mil polyethylene asbestos bags. When the tile removal is complete the bags will be removed from the building and placed in a sealed and lined roll-off box for transport to the landfill for disposal.

Brandenburg, Industrial Service Company
1680 John A. Papalas Drive
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Roofing Materials

The roofing materials identified in the survey will be removed as part of the demolition of the building. The roof will be wetted with water from fire hoses during the demolition process. Once the roofing materials are pulled to the ground the material will be loaded into Brandenburg trucks for transporting to the landfill as C&D waste material.

Following the removal of all regulated materials, Brandenburg will prepare for the demolition. Brandenburg shall utilize skid steers equipped with biter buckets placed inside of the existing structure to remove the remaining combustible materials from the structure. These materials shall be removed from the building by way of an access opening within an existing exterior wall. Said opening shall be large enough for the easy ingress and egress of the skid steers operating within the structure. Once the material is outside of the existing structure, Brandenburg shall load and transport the waste to the landfill. A combination of a CAT 980 wheel loader and the Bobcat Skid Steer Loaders will be used to load the trucks.

Following, the interior strip out of the existing structure, Brandenburg shall begin the structural removal efforts. Brandenburg will utilize one or two Leibherr 954 hydraulic excavators equipped with whip hammers, hydraulic shears, grapples, and /or hydraulic hammers in order to raze the existing structure in a controlled manner. The excavating equipment will "bite" into the structure and pull the building apart.

The scrap steel material will be pulled from the building and separated from the building debris. The debris will be loaded into Brandenburg trucks for shipment to the landfill. As the building is removed, an area may be established for hot work in order to size some of the structure steel or other heavy steel. The steel will be eventually be loaded and shipped off site to a scrap steel recycler.

Brandenburg will utilize onsite concrete as backfill material for the areas affected by the removal efforts. Backfill shall be placed and rough graded to the top of the elevation of the surrounding grade.

Unit 1 and 2 Stack & Cooling Towers

Following the completion of demolition of Units 1& 2 and all supporting building structures, tanks, conveyors and equipment, Brandenburg crews will implode the stack and (2) cooling towers.

Brandenburg crews will go through the structures performing the initial walk through to verify that the utilities have been disconnected, isolated or air gapped. Following the walk through, barricades consisting of snow fence and caution or danger tape will be placed at entry areas of the structure to limit access.

Once the concrete structures are imploded, Brandenburg will segregate the scrap steel from the concrete. The steel will be loaded and shipped off-site to a scrap recycler. The concrete will be processed to two feet or less in size and used as bridging material at the slurry ash ponds prior to capping with clay.

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1680 John A. Papalas Drive
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Bottom Ash Ponds

Brandenburg will remove, transport and dispose of the piping from the boiler units to the ponds. Brandenburg will dewater the bottom ash ponds. The water will be filtered and discharged into the Big Sandy River. Brandenburg will then import clay from the AEP clay borough and place a two feet clay cap on any remaining bottom ash accumulations.

Slurry Ash Ponds

Brandenburg will remove, transport and dispose of the piping from the boiler units to the ponds. Brandenburg will allow the slurry ash ponds to drain naturally. Once drained, concrete from the demolition of the stack and cooling towers will be utilized to stabilize bridge the ground. The area will be graded and Brandenburg will import clay from the on-site AEP clay borough and place a two foot clay cap over the 150 acre area. Brandenburg will grade the area to allow for water to drain toward Blaine Creek.

Aboveground/Underground Storage Tanks

Brandenburg shall remove all above ground tanks, including pipe racks, supports, and appurtenances utilizing a hydraulic excavator equipped with a hydraulic shear to cut the existing piping, tank, and appurtenances. Scrap steel shall be segregated, loaded, and hauled off site to a steel recycler. Brandenburg will then remove the tank dike walls down to surrounding grade elevation or top of tank slab. The Tank Ring foundations shall remain in place.

Brandenburg will remove all below grade tanks, pumps and below grade product lines. The tanks will be emptied by conventional means. A hydraulic excavator will be used to excavate and remove the tanks. Brandenburg will utilize onsite concrete as backfill material for the areas affected by the removal efforts. Backfill shall be placed and rough graded to the top of the elevation of the surrounding grade.

Volumes

Demolition Material	Volume
Concrete	35,000 yards
Asbestos	3,000 yards
Demolition Debris	5,000 yards
Railroad Ties	30,666 ties
Brick	6,500 yards
Scrap Ferrous Steel	22,000 tons
Scrap Non-ferrous Steel	290,000 lbs
Oils/Greases	50,000 gallons

AMM Scrap Iron & Steel Prices

Wednesday, December 29, 2004

CONSUMER BUYING PRICES

ted domestic consumer buying prices in US$/gross ton; delivered mill price.

	Birmingham	Carolinas	Chicago	Cleveland	Detroit	Houston area	N.Y	Philly	P-burgh	Seattle/ Portland	St. Louis	Youngstown	Hamilton, Ontario†	Montreal†
N. 1 HEAVY MELT	180	127-129	220	215	245	130-132	200-202	208-210	220	110-112	130	220	125	180
2 heavy melt	170	118-120	210	205		115-117	190-192	195-197	212	107-108	120	210		145
No. 1 bundles	340		390	398	373	370	NA	375	398-400	NA	315	NA	292-294	
No. 2 bundles	150	100(a)	170		NA	110(a)	NA	170	160(a)	93-95	NA	150(a)		NA
No. 1 bushelling	320	290-292	390	370	378	375	375	375	405		315	395	296-298	255
No. 1 factory bundles			418	416	420			NA	416					
Shredded auto scrap	270	235	275	260	260	245	250-252	250	250	127-129	205	260	155	250
MACHINE SHOP TURNINGS	130	90	175	95(a)		35(a)	160	153-155	165(a)	85-86	83-85		30	120
Shoveling turnings	NA		175	100(a)		45(a)	NA	163-165	165(a)		83-85		40	
Cast iron borings	NA		165	85(a)						NA	82-84			
Mixed borings, turnings	NA		165	NA						70-71				
CUT STRUCTURAL/PLATE, 2' MAX.	NA	165	370			243-245	NA	335	NA	NA	NA		NA	270
Cut structural/plate, 3' max.	256	155				233-235	NA	290	310		170			
Cut structural/plate, 5' max.	212	145	275	240(a)	255	225-227	210-212	236-238	260	125-127	160	260	165	215
Foundry steel, 2' max.	245		215	265	240	180		260	240			280		
CUPOLA CAST	220	195	270	270	250	180	250(a)	270	280	NA				220
Clean auto cast	270	283	315	310	260			330	300					
Unstripped motor blocks	183-185	230	240	230	210	185	NA	195	200					
Heavy breakable cast	160		160	190	180			140	150					
Drop broken machinery cast		280	300	275	240			315	280	144-145			240	265
NO. 1 RR HEAVY MELT	220	150	275	240		228-230		280	280	140-142	185	275		
Rail crops, 2' max.	103(a)	300	380	375				375	375					
Random rails	175		250					210	275	125-127				
Steel car wheels	265	280	390					385	380					
Other track material (OTM)	270	295	280	350				340	370	170-172				
CLEAN USED DENSIFIED CANS			235	235	245			225	185					

(a) Appraisal price
NA—Not available
† Canadian currency; in net tons

STAINLESS STEEL SCRAP

	Boston	Buffalo	Chicago	Cleveland	Detroit	Houston	L.A	N.Y	P-burgh	S.F	Montreal†
DEALERS' BUYING PRICES (¢/lb.)											
18-8 bundles, solids, clips	49-50	49-50	50-51	50-51	50-51	50-51	50-51	50-51	50-51	49-50	52-53
18-8 turnings	45-46	45-46	46-47	46-47	46-47	46-47	46-47	46-47	46-47	45-46	48-50
18-8 new clips		50-51	51-52	51-52	51-52		51-52	51-52	51-52	50-51	54-56
430 new clips	7.5-8.0		7.5-8.0	7.5-8.0	7.5-8.0			7.5-8.0	7.5-8.0		
BROKER/PROCESSOR BUYING PRICES ($/gross ton)											
18-8 bundles, solids, clips			1,375-1,400	1,375-1,400	1,375-1,400	1,375-1,400		1,375-1,400	1,375-1,400		
18-8 turnings			1,275-1,300	1,275-1,300	1,275-1,300	1,275-1,300		1,275-1,300	1,275-1,300		
430 bundles, solids			355-365		355-365	355-365			355-365		
430 turnings			305-315						305-315		
409 bundles, solids			330-340		330-340	330-340			330-340		
409 turnings									255-265		

† Canadian currency

EXPORT YARD BUYING PRICES

Estimated prices an export dealer, broker or processor will pay for items delivered to his yard, in US$/gross ton.

	Boston	L.A	N.Y	Philly	S.F
No. 1 heavy melt	170-172	90-92	180-182	195-197	90-92
No. 2 heavy melt	160-162	80-82	170-172	185-187	80-82
No. 2 bundles	100(a)	NA	110(a)	116(a)	60-62
No. 1 bushelling	300		310		
Shredded auto scrap	240				
Machine shop turnings	NA	70	110(a)		70
Mixed cast	170		180	200	
Unstripped motor blocks	170	130	170	180	130
Auto bodies	110	100	135	135	90
Cut structural/plate 5' max.	160-162		190-192	218-220	
STAINLESS STEEL SCRAP PRICES ($/ton)					
18-8 bundles, solids, clips		1,375-1,400	1,375-1,400	1,375-1,400	1,375-1,400
18-8 turnings		1,275-1,300	1,275-1,300	1,275-1,300	1,275-1,300
430 bundles, solids	260	245	245	245	

(a) Appraisal price

BROKER BUYING PRICES

Estimated prices in US$/gross ton, f.o.b. car*

	Atlanta	Boston	Buffalo	Cincinnati	Detroit
NO. 1 HEAVY MELT	180	180	185	190	230
No. 2 heavy melt	160	170	175	180	
No. 1 bundles	305	330	330	325	340
No. 2 bundles	150	170	180	160	200
No. 1 bushelling	300	330	330	323	355
Shredded auto scrap	240	240	220	220	250
MACHINE SHOP TURNINGS		NA	140	135	130
Shoveling turnings		NA	150	150	130
Cast iron borings		NA	140	135	140
Mixed borings, turnings			140		130
CUPOLA CAST			200	200	180
Cut structural/plate, 5' max.	205		200	200	240
Cut structural/plate, 2' max.			300	295	340
Clean auto cast				300	285
Unstripped motor blocks		180	200		175
Heavy breakable cast		NA	170		145
Drop broken machinery cast		NA	250		250
Rail crops, 2' max.			260	240	
Random rails			200	160	

*f.o.b. (free on board at the shipping point) from dealer to broker where freight rate is absorbed by broker; freight rate based on single car shipments.

STAINLESS CONSUMER BUYING PRICES

($/grosston)

Pittsburgh

18-8 bundles, solids, clips 1,500-1,525
18-8 turnings 1,400-1,425
430 bundles, solids 470-480
430 turnings 420-430
409 bundles, solids 430-440
409 turnings 350-360

ADDITIONAL GRADES

Birmingham

Electric furnace, 3' max. 205
Cut structural/plate, 4' max. 240
Stove plate 220

Chicago

No. 1 industrial heavy melt 275
Rail crops, 18" max. 395
Rerolling rails 325
Steel axles 310
Heavy forge bar crops 290
Stove plate 270
Punching & plate, 12" max. 380

Scrap Price Changes Today

Ferrous scrap price changes were made for these cities:
None

Disclaimer

Prices and other information contained in this publication have been obtained by *American Metal Market* ("AMM") from sources believed to be reliable. Pricing information is collated through regular contact with producers, traders and purchasers, and represents an approximate evaluation of current levels based upon dealings (if any) that may have been disclosed to *AMM* prior to publication. Actual transaction prices will reflect quantities, grades and qualities, credit terms and many other parameters. The prices are in no sense comparable to the quoted prices of commodities in which a formal futures market exists. Efforts are made to ensure that pricing information is representative, but because of the possibility of human or mechanical error by our sources, *AMM* or others, *AMM* does not guarantee the accuracy or completeness of any published information. *AMM* is not responsible for errors or omissions, or for the results obtained by the use of such information, and disclaims any liability to any person for any loss or damage caused by such errors or omissions, including those arising from the negligence of *AMM*, its employees or representatives.

AMM Nonferrous Scrap Prices

Wednesday, December 29, 2004

Estimated dealer buying prices, in ¢/lb, delivered to yard. Montreal and Toronto prices are in Canadian currency.

COPPER

	Atlanta	Boston	Buffalo	Chicago	Cincinnati	Cleveland	Detroit	Houston	L.A.	N.Y	Philly	P-burgh	S.F	St. Louis	Montreal	Toronto
No. 1 heavy copper & wire	116-118	102-104	86-88	97-99	97-99	116-117	95-97	103-105	100-102	98-100	100-102	101-103	100-102	106-108	157-159	132-134
No. 2 HEAVY COPPER & WIRE	96-98	92-94	76-78	89-91	86-88	103-105	85-87	92-94	90-92	88-90	90-92	91-93	90-92	96-98	128-130	116-118
Light copper	81-83	83-85	71-73	79-81	81-83	95-97	80-82	80-82	85-87	81-83	84-86	79-81	83-85	88-90	121-123	104-106
RED BRASS SOLIDS	73-75	58-60	43-45	59-61	56-58	74-76	54-56	60-62	62-64	51-53	56-58	53-55	63-65	66-68	95-97	87-89
Red brass turnings, borings	64-66	57-59	43-45	56-56	52-54	54-56	44-46	52-54	59-61	54-56	56-58	47-49	55-57	58-60	91-93	74-76
Cocks & faucets	60-62	54-56	38-40	56-58	51-53	54-56	44-46	51-53	60-63	54-56	56-58	47-49	55-57	66-68	80-82	66-68
Brass pipe	88-90	54-56	39-41	56-58	60-62	54-56	45-47	51-53	61-63	55-56	56-58	47-49	55-57	66-68	80-82	82-84
YELLOW BRASS SOLIDS	62-64	54-56	39-41	56-58	50-52	54-56	44-46	51-53	55-57	55-56	56-58	53-55	30-32	56-58	76-78	68-70
Mixed yellow brass turnings, borings	45-47	33-35	27-29	27-29	25-27	22-24	25-27	34-36	29-31	25-27	29-31	22-24	60-62	25-27	54-56	38-40
Yellow brass rod ends	78-80	52-54	44-46	54-56	51-52	82-84	47-49	58-60	55-57	51-53	51-53	50-52	59-61	80-82	104-106	88-90
Yellow brass rod turnings	76-78	50-52	43-44	53-55	48-49	80-82	45-47	57-59	53-55	49-51	48-50	49-51	58-60	78-80	100-102	86-88
70-30 brass clips	85-87	60-62	54-56	51-53	67-69	90-92	53-55	69-70	60-62	61-63	68-70	62-64	65-67	91-93	115-117	78-80
AUTO RADIATORS (UNSWEATED)	60-62	45-47	38-40	43-45	48-50	63-65	48-48	49-51	53-55	43-45	42-44	42-44	55-57	50-52	70-72	65-67
High-grade bronze gears	73-75	65-67	58-60	52-54	62-64	60-62	47-49	68-70	51-53	60-62	61-63	60-62	62-64	50-52	110-112	72-74
High-grade low lead bronze	73-75	35-37	53-55	48-50	NA	60-62	NA	45-47	45-47	55-57	57-59	48-50	58-60	45-47	85-87	....
Manganese bronze solids	40-42	35-37	38-40	31-33	39-41	30-32	18-20	47-49	37-39	41-43	42-44	36-38	37-39	33-35	65-67	46-48
Miscellaneous nickel-"silver" solids	62-64	39-41	38-40	35-37	38-40	54-56	20-22	51-53	35-37	43-45	43-45	42-44	37-39	37-39	75-77	....
Manganese bronze turnings	24-26	24-26	25-27	23-25	26-27	26-27	5-7	30-32	23-25	27-29	27-29	25-27	26-27	21-23	55-57	28-30

ALUMINUM

	Atlanta	Boston	Buffalo	Chicago	Cincinnati	Cleveland	Detroit	Houston	L.A	N.Y	Philly	P-burgh	S.F	St. Louis	Montreal	Toronto
Segregated low copper clips	44	43	49	46	45	46	44	43	44	49	49	44	44	41	63	53
Mixed low copper clips	42	39	45	38	41	43	41	42	39	44	44	40	39	37	44	44
Mixed clips	39	38	43	35	37	39	37	38	37	42	42	38	37	35	43	43
Aluminum borings, turnings, clean & dry	34	30	31	33	35	31	33	36	32	35	27	26	32	28	42	42
Old aluminum, sheet & cast	34	35	36	29	36	40	34	37	36	38	39	36	36	34	43	43
Used beverage cans, clean & dry	35	NA	34	30	34	36	NA	NA	NA	35	35	34	NA	33		
Industrial castings	48	42	45	....	....	....	42	....	....	....	NA	....	....	44	....	....
63S aluminum solids	48	44	62	43	....	....	48	....	....	....	50	....	....	47	56	56
75S aluminum clips	42	38	43	....	....	....	42	....	46	NA	46	....	NA	....	....	....
75S borings, turnings, as is	33	....	31	....	....	....	....	....	30	NA	29	....	NA	....	....	....
Aluminum utensils	NA	NA	43	NA	....	....	NA	....	....	....	NA	....	....	NA	41	41
Painted aluminum siding	39	38	41	37	....	....	38	....	....	....	41	....	....	35	....	53

(a) Appraisal price

LEAD

	Atlanta	Boston	Buffalo	Chicago	Cincinnati	Cleveland	Detroit	Houston	L.A	N.Y	Philly	P_burg	S.F	St. Louis	Montreal	Toronto
HEAVY SOFT LEAD	6-6	6-7	6-7	6-7	6-7	6-7	6-7	6-7	6.5-7.5	5	6	6-7	5-6	6-7	16-18	15-17
Mixed hard lead	6.5-7.5	....	....	....	8.5	....	8.6	....	....	....	....	9	8-10	....	17-19	16-17
Undrained, whole old batteries	....	....	....	....	....	....	3	3	2.5-3.5	3	2	3-4	4	3-4	4-6	4-6
WHEEL WEIGHTS	7-9	8-10	8-9	10-11	11	....	11	6-8	5-7	....	4	8	9-11	....	15-16	10-12

ZINC

	Atlanta	Boston	Buffalo	Chicago	Cincinnati	Cleveland	Detroit	Houston	L.A	N.Y	Philly	P-burgh	S.F	St. Louis	Montreal	Toronto
N... zinc die cast	....	28-29	28-29	29-31	27-28	....	30-32	31-32	27-28	29	....	30-32	27-28	28-31	40-42	40-42
OLD ZINC DIE CAST	....	26-27	26-27	27-28	23-24	....	24	30-31	26-27	26	25	28-29	25-26	....	38-40	38-40
... zinc scrap	....	21-23	21-23	25-26	21-23	....	24	....	20-21	24	25	23-25	....	....	38-40	38-40
...W ZINC CLIPPINGS, ENGRAVERS' ZINC & LITHO SHEETS	....	31-32	31-32	34-36	24-25	....	29	....	26-29	31-32	38	29-31	27-28	31-32	38-40	38-40
Zinc die cast automotive grilles	....	....	....	....	23-24	....	23	....	....	NA	NA	NA	23	....	40-42	40-42

NICKEL

	Atlanta	Boston	Buffalo	Chicago	Cincinnati	Cleveland	Detroit	Houston	L.A	N.Y	Philly	P-burgh	S.F	St. Louis	Montreal	Toronto
New nickel clips & solids	490-500	480-490	480-490	490-500	490-500	490-500	490-500	490-500	480-490	490-500	490-500	490-500	480-490	480-490	640-650	640-650
Nickel turnings	480-490	....	470-480	480-490	....	480-490	480-490	480-490	....	....	....	480-490	....	....	530-540	....
New nickel-copper alloy (e.g., Monel®) clips & solids	340-350	330-340	330-340	340-350	340-350	340-350	340-350	340-350	330-340	340-350	340-350	340-350	330-340	330-340	....	....
Nickel-copper alloy (e.g., Monel®) turnings & shavings	330-340	320-330	320-330	330-340	330-340	330-340	330-340	330-340	320-330	330-340	330-340	330-340	320-330	....	....	....
Nickel-copper alloy (e.g., Monel®) castings	335-340	325-335	325-335	335-340	335-340	335-340	335-345	335-345	325-335	....	335-345	335-345	....	325-335	....	....
Nickel-chrome-iron alloy (e.g., Inconel®) solids	400-410	400-410	400-410	400-410	390-400	400-410	400-410	400-410	390-400	390-400	400-410	400-410	390-400	390-400	440-450	440-450

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SCRAP METALS

Estimated buying prices
(carload lots, delivered buyers' works)

BRASS MILL SCRAP

No. 1 copper	144.00*

REFINERS' COPPER SCRAP

No. 1 copper	137.00*
No. 2 copper	124.00*
Light copper	115.00*
Refinery brass†	NA

† Shippers' price for dry copper content assaying a min. 61.3% copper and a max. 5% iron.

BRASS INGOT MAKERS' SCRAP

(rev. 12/28/2004)

Copper	East	Midwest
No. 1	133.00*	132.00*
No. 2	120.00*	119.00*
Light copper	111.00*	110.00*
No. 1 comp. solids (rev. 12/10/04)	95.00	95.00
..., borings, turnings (rev. 12/10/04)	94.00	94.00
...llators (rev. 12/10/04)	75.00	75.00
...w brass solids (rev. 12/10/04)	70.00	70.00
Turnings (rev. 12/10/04)	60.00	60.00

SMELTERS' LEAD SCRAP

Buying prices heavy soft lead (cwt), including delivery to smelter

(rev 09/14/04)

Scrap lead	$20.00-$21.00
Remelt lead	$21.00-$22.00
Whole batteries	$7.50-$8.00
Cable lead	$22.00

SMELTERS' ZINC SCRAP

(rev. 12/28/04)

New zinc clippings	36.00-37.00
Old zinc (clean)	34.00-35.00
Die cast slab	36.00-37.00
Galvanizers' dross	29.00-30.00

SECONDARY SMELTERS' ALUMINUM SCRAP

Buying prices delivered to the smelter in full truckloads containing several grades

(rev.12/28/2004)

Mixed low copper clips	61.00-62.00
Mixed high copper clips	59.00-60.00
Mixed high zinc clips	57.00-58.00
1-1-3 sows	62.00-63.00
Siding, painted	57.00-58.00
Mixed clips	57.00-58.00
Old sheet and cast	58.00-59.00
Turnings, clean & dry	54.00-55.00
Aluminum-copper radiators	79.00-80.00
Nonferrous auto shred (90% alum.)	*52.00-53.00

* Unmixed full truckload, "twitch" grade

DOMESTIC ALUMINUM PRODUCERS

Buying prices for processed used aluminum cans in carload lots, f.o.b. shipping point (rev. 12/07/04)

Used beverage can scrap	63.00-65.00

MILLS, SPECIALTY CONSUMERS' BUYING PRICES

(rev.12/28/2004)

Segregated low copper alloy clips	80.00-81.00
Mixed low copper alloy clips	72.00-73.00
Painted siding	66.00-67.00

* Nominal for spot sales.

Scrap Price Changes Today
Nonferrous scrap price changes were made to these cities:
None

Prices are subject to the Disclaimer appearing on the "AMM Scrap Iron & Steel Prices" page.

AEP Company
Re-sale of Equipment

May 31, 2005

Resalable valve of equipment

The equipment that has re-sale value are as follows:

The coal pulverizers used to pulverize the coal blown into the boiler as fuel.

The Unit 1 cooling tower water pumps and motors used to move the cooling water from the cooling tower to the turbine generator condensers.

The Unit 2 cooling tower pumps and motors used to move the cooling water from the cooling tower to the turbine generator condensers.

The three, Unit 1 step-up transformers, after the generator.

The five, Unit 2 step-up transformers, after the generator.

The four, plant step-down transformers, at the west substation yard.

The amount of money that the equipment is worth is a small amount. Because of the age of the equipment, the transformers will range in price from $2.00 to $4.00 per KVA. The pumps and AC motors will range around $5.00 per horsepower. And the coal pulverizers will range in resale value of $3,500.00 to $5,000.00 each depending on condition and date of rebuild. The total resalable value today for equipment that is resalable is $250,000.00.

Recommendations

Brandenburg recommends that a detailed asbestos survey be performed to determine the exact volume of asbestos present on the property.

Brandenburg recommends that instead of capping the slurry ash ponds, AEP request a variance from the State of Kentucky to maintain the area as a protected wetland/ wildlife habitat.

Kentucky Power Company

REQUEST

Direct Testimony of McManus page 22 lines 8-10 regarding "FGD (Hg) Waste Water Treatment system installation" at the Amos Plant and Exhibit JMM-1 with description of Applicable Environmental Program with CWA NPDES.

a. Please provide the current NPDES permit for Big Sandy 2.

b. If applicable, please provide any of the Company's recent applications for changes or modifications to the NPDES permit for Big Sandy 2.

c. Does the Company anticipate that the pending Effluent Limitation guidelines rule could impact Big Sandy 2?

d. If so, what would be the expected cost of this rulemaking. If not, why?

e. Has a cost for the pending Effluent Limitation guidelines been taken into account modeling the cost efficacy of Big Sandy 2? If not, how would such a cost impact this analysis?

RESPONSE

a. Please see Sierra Club Set 1-25 Attachment 1 for the current NPDES permit for Big Sandy Unit 2.

b. Please see Sierra Club Set 1-25 Attachment 2 for the Company's most recent application for modifications to the NPDES permit for Big Sandy Unit 2.

c. Yes, the pending Effluent Limitation guidelines rule will apply to Big Sandy Unit 2 as these guidelines apply to all steam electric generating plants in the U.S.

d. The cost efficacy modeling for Big Sandy Unit 2 does include a very high-level estimate to provide for installation of a waste water treatment plant as part of the overall compliance strategy being driven by EPA rulemakings, including the Effluent Guidelines. Please refer to the response for KPSC Staff 1-47. However, the Effluent Limitation Guidelines Rule is not expected to be issued in proposed form until July, 2012 and so we have had to make assumptions regarding the design of that system that may be significantly changed as the rulemaking progresses.

e. Please see the response to item d.

WITNESS: John M McManus

KPDES

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT

PERMIT NO.: KY0000221

AUTHORIZATION TO DISCHARGE UNDER THE KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

Pursuant to Authority in KRS 224,

Kentucky Power Company
1 Riverside Plaza
Columbus, Ohio 43215-2373

is authorized to discharge from a facility located at

Kentucky Power Company
Big Sandy Plant
U.S. Highway 23
Louisa, Lawrence County, Kentucky

to receiving waters named

Outfalls 001 and 018 are to Blaine Creek at milepoints 2.0 and 1.9, respectively.
Outfalls 002, 003, and 005 are to Outfall 001 via the bottom ash pond.
Outfalls 004, 007 through 017, and 019 are to the Big Sandy River between milepoints 19.6 and 20.45.
Outfall 006 is the plant intake.

in accordance with effluent limitations, monitoring requirements, and other conditions set forth in PARTS I, II, III, IV, and V hereof. The permit consists of this cover sheet and PART I 8 pages, PART II 1 page, PART III 1 page, PART IV 3 pages, and PART V 3 pages.

This permit shall become effective on APR 1 2003

This permit and the authorization to discharge shall expire at midnight, March 31, 2006.

FEB 4 2003
Date Signed

Jeffrey W. Pratt, Director
Division of Water

Robert W. Logan
Commissioner

DEPARTMENT FOR ENVIRONMENTAL PROTECTION
Division of Water, Frankfort Office Park, 14 Reilly Road, Frankfort, Kentucky 40601

Printed on Recycled Paper

A1. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 001 - Combined wastewaters of fly ash pond overflow (ash transport waters, coal pile runoff and bottom ash pond overflow consisting of low volume wastes, sump waters, storm water runoff, metal cleaning wastes (Outfall 005), and cooling tower blowdown (Outfalls 002 and 003)).

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	2/Month	Instantaneous
Total Suspended Solids (mg/l)	30	60	2/Month	Grab
Oil & Grease (mg/l)	6.0	6.0	2/Month	Grab
Hardness (as mg/l)($CaCO_3$)	Report	Report	2/Month	Grab
Total Recoverable Metals (mg/l)	Report	Report	1/Quarter	Grab
Chronic Toxicity (TU_c)	N/A	2.12	1/Quarter	3 Grabs

The pH of the effluent shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored 2/Month by grab sample.

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

The abbreviation N/A means Not Applicable.

The effluent characteristic "Total Recoverable Metals" means Antimony, Arsenic, Beryllium, Cadmium, Chromium, Copper, Lead, Mercury, Nickel, Selenium, Silver, Thallium, and Zinc. To report the results of the analyses for this parameter, the permittee shall total the results of the analyses for each individual parameter, and report that aggregate value on the DMR. The laboratory bench sheets showing the results for each parameter shall be attached to the DMR.

A2. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 002 - Unit 1 cooling tower blowdown. Outfall 002 is an internal outfall discharges to Outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Month	Calculated
Free Available Chlorine (mg/l)	0.2	0.5	Occurrence	Multiple Grab
Total Residual Chlorine (mg/l)	0.2	0.2	Occurrence	Multiple Grab
Total Residual Oxidants (mg/l)	Report	0.2	Occurrence	Multiple Grab
Time of Oxidant Addition (Minutes/unit/day)	N/A	120	Occurrence	Log
Total Chromium (mg/l)	0.2	0.2	Annually	Grab
Total Zinc (mg/l)	1.0	1.0	Annually	Grab
Priority Pollutants (mg/l)	Report	NDA	Annually	Grab

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

Priority Pollutants shall be monitored annually by grab sample or by engineering calculations. The results of the analyses/engineering calculations shall be totaled and reported as a single concentration on the DMR. The laboratory bench sheets/engineering calculations showing the results for each pollutant shall be attached to the DMR. The term Priority Pollutants means the 126 priority pollutants listed in 40 CFR Part 423 Appendix A. See Attachment A - Fact Sheet Addendum for Steam Electric Power Generating Plants.

The term Total Residual Oxidants (TRO) means the value obtained using the amperometric titration or DPD methods for total residual chlorine described in 40 CFR Part 136. In the event of addition of an oxidant other than chlorine, the permittee shall receive prior approval from the Division of Water permitting staff before the initial use.

The measurement frequency "Occurrence" means during periods of chlorination or oxidant addition, but no more frequent than once per week.

The sample type "Multiple Grab" means grab samples collected at the approximate beginning of oxidant discharge and once every fifteen (15) minutes thereafter until the end of oxidant discharge.

The abbreviation N/A means Not Applicable.

The abbreviation NDA means No Detectable Amount.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 003 - Unit 2 cooling tower blowdown. Outfall 003 is an internal outfall that discharges to Outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Month	Calculated
Free Available Chlorine (mg/l)	0.2	0.5	Occurrence	Multiple Grab
Total Residual Chlorine (mg/l)	0.2	0.2	Occurrence	Multiple Grab
Total Residual Oxidants (mg/l)	Report	0.2	Occurrence	Multiple Grab
Time of Oxidant Addition (Minutes/unit/day)	N/A	120	Occurrence	Log
Total Chromium (mg/l)	0.2	0.2	Annually	Grab
Total Zinc (mg/l)	1.0	1.0	Annually	Grab
Priority Pollutants (mg/l)	Report	NDA	Annually	Grab

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

Priority Pollutants shall be monitored annually by grab sample or by engineering calculations. The results of the analyses/engineering calculations shall be totaled and reported as a single concentration on the DMR. The laboratory bench sheets/engineering calculations showing the results for each pollutant shall be attached to the DMR. The term Priority Pollutants means the 126 priority pollutants listed in 40 CFR Part 423 Appendix A. See Attachment A - Fact Sheet Addendum for Steam Electric Power Generating Plants.

The term Total Residual Oxidants (TRO) means the value obtained using the amperometric titration or DPD methods for total residual chlorine described in 40 CFR Part 136. In the event of addition of an oxidant other than chlorine, the permittee shall receive prior approval from the Division of Water permitting staff before the initial use.

The measurement frequency "Occurrence" means during periods of chlorination or oxidant addition, but no more frequent than once per week.

The sample type "Multiple Grab" means grab samples collected at the approximate beginning of oxidant discharge and once every fifteen (15) minutes thereafter until the end of oxidant discharge.

The abbreviation N/A means Not Applicable.

The abbreviation NDA means No Detectable Amount.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 004 ~ Sanitary wastewater.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Month	Instantaneous
Biochemical Oxygen Demand, 5-day (mg/l)	30	45	1/Month	Grab
Total Suspended Solids (mg/l)	30	45	1/Month	Grab
Ammonia (as N) (mg/l)	20	30	1/Month	Grab
Fecal Coliform Bacteria (#/100 ml)	200	400	1/Month	Grab
Dissolved Oxygen (minimum) (mg/l)	2.0	N/A	1/Month	Grab
Total Residual Chlorine (mg/l)	0.019	0.019	1/Month	Grab

The pH of the effluent shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored 1/Month by grab sample.

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

The abbreviation N/A means Not Applicable.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 005 - Metal cleaning wastes. Outfall 005 is an internal outfall that discharges to Outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Batch	Calculated
Total Copper	1.0 mg/l	1.0 mg/l	1/Batch	Grab
Total Iron	1.0 mg/l	1.0 mg/l	1/Batch	Grab

The pH of the effluent shall be monitored 1/Batch by grab sample.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest point prior to commingling with the waters of either ash pond.

Metal cleaning waste shall mean any wastewater resulting from cleaning (with or without chemical cleaning compounds) any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning. In accordance with the conditions of the previous permits, the permittee is allowed to discharge air preheater wash waters and boiler fireside cleaning directly to the ash pond without limitations or monitoring requirements, pursuant to the Jordan Memorandum. Monitoring is required only when chemical metal cleaning activities are being performed.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 006 - Plant intake.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS Monthly Avg.	DISCHARGE LIMITATIONS Daily Max.	MONITORING REQUIREMENTS Measurement Frequency	MONITORING REQUIREMENTS Sample Type
Flow (MGD)	Report	Report	1/Week	Instantaneous
Temperature (°F)	Report	Report	1/Week	Grab
Total Suspended Solids (mg/l)	Report	Report	1/Week	Grab
Hardness (as mg/l)($CaCO_3$)	Report	Report	1/Week	Grab
pH (Standard Units)	Report	Report	1/Week	Grab
Total Recoverable Metals	N/A	Report	1/Quarter	Grab

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: plant intake, except that temperature may be monitored at the river pumps.

The effluent characteristic "Total Recoverable Metals" means Antimony, Arsenic, Beryllium, Cadmium, Chromium, Copper, Lead, Mercury, Nickel, Selenium, Silver, Thallium, and Zinc. To report the results of the analyses for this parameter, the permittee shall total the results of the analyses for each individual parameter and report that aggregate value on the DMR. The laboratory bench sheets showing the results for each parameter shall be attached to the DMR.

A4. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: **Outfall 007** - Storm water runoff from 91.8 acres north of U.S. Highway 23, the area north of Unit 2, and the area around the performance building and behind the storage warehouses. Additional wastewaters include occasional fire header flushing, Unit 1 cooling tower emergency overflow and cooling waters and auxiliary blowdown during Unit 2 outage, **Outfall 008** - Storm water runoff from 5.7 acres west of Unit 2 coal storage area and Unit 2 turbine roof drains. Additional wastewaters include Unit 2 condensate storage tank overflow, Unit 2 wastewater sump overflow, south Unit 2 coal pile drainage pond sump overflow, occasional fire header flushing and Unit 2 cooling tower emergency overflow, **Outfall 009** - Storm water runoff from 104.3 acres north of U.S. Highway 23 and north of Unit 2 coal storage area, **Outfall 010** - Storm water runoff from 0.8 acres east of Unit 2 coal yard buildings, **Outfall 011** - Storm water runoff from coal yard building roof drains and 1.3 acres south of Unit 2 coal yard buildings, **Outfall 012** - Has been eliminated by rerouting to coal pile runoff ponds, **Outfall 013** - Storm water runoff from 0.4 acres south of Unit 2 cooling tower, **Outfall 014** - Storm water runoff from 2.0 acres west of Unit 2 cooling tower, **Outfall 015** - Storm water runoff from 1.7 acres around storeroom warehouses, parking lot and roof drains, **Outfall 016** - Storm water runoff from 0.7 acres around Unit 1 condensate storage tank and road. Additional wastewaters include Unit 1 condensate storage tank overflow, Unit 1 cooling tower basin drain, and tower flume overflow, **Outfall 017** - Storm water runoff from 38.8 acres north of U.S. Highway 23 around bottom ash ponds and parking lot, Unit 1 service building, coal storage area, tractor sheds, and roof drains, **Outfall 018** - Interior drains of the fly ash dam. May include overflow of mine seepage sump if sump pump fails, and **Outfall 019** - Storm water runoff from 1.5 acres east of Unit 1 cooling tower.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type

The Division of Water has determined that implementation of Best Management Practices (BMPs) would be the most effective approach for controlling pollutants from these areas.

B. Schedule of Compliance

The permittee shall achieve compliance with all requirements on the effective date of this permit.

C. Cooling Water Additives, FIFRA, and Mollusk Control

The discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) in cooling water which ultimately may be released to the waters of the Commonwealth is prohibited, except Herbicides, unless specifically identified and authorized by the KPDES permit. In the event the permittee needs to use a biocide or chemical not previously reported for mollusk control or other purpose the permittee shall submit sufficient information, a minimum of thirty (30) days prior to the commencement of use of said biocides or chemicals, to the Division of Water for review and establishment of appropriate control parameters. Such information requirements shall include:

1. Name and general composition of biocide or chemical,
2. Any and all aquatic organism toxicity data,
3. Quantities to be used,
4. Frequencies of use,
5. Proposed discharge concentrations, and
6. EPA registration number, if applicable.

D. Polychlorinated Biphenyls

Pursuant to the requirements of 401 KAR 5:065, Section 4(4) (40 CFR Parts 423.12(b)(2) and 423.13(a)), there shall be no discharge from any point source of polychlorinated biphenyl compounds such as those commonly used in transformer fluids. The permittee shall implement this requirement as a specific section of the BMP plan developed for this station.

E. Selective Catalytic Reduction Devices or Systems (SCRs) and Nonselective Catalytic Reduction Devices or Systems (NSCRs)

In response to recent Clean Air Act amendments, the installation of these devices for NOx reduction may become necessary. Associated with the installation and operation of these units, an "ammonia slip" may occur resulting in the discharge of ammonia to the ash pond. The impact of such an occurrence on the performance of the ash pond and any eventual impact on the environment is not known. Therefore, should it become necessary to install these devices, the permittee shall develop and implement an Ammonia Monitoring Plan. The plan shall be submitted to the Division of Water within ninety (90) days of the determination that these devices will be installed, and shall include at a minimum influent and effluent monitoring of each unit on a monthly basis with submission of the data as a quarterly report.

F. Section 311, Clean Water Act Exclusion

The permittee is relieved of the reporting and liability requirements under Section 311 of the Clean Water Act for the following substances, consistent with Exclusion 2, authorized by Section 311(a)(a)(B) and 40 CFR Part 117.12 for: Ammonium Hydroxide, Sodium Hypochlorite, Ethylene Diaminetetracetic Acid (EDTA), Sodium Hydroxide, Sodium Nitrite, Sodium Phosphate (Dibasic), and Sulfuric Acid.

STANDARD CONDITIONS FOR KPDES PERMIT

The permittee is also advised that all KPDES permit conditions in KPDES Regulation 401 KAR 5:065, Section 1 will apply to all discharges authorized by this permit.

This permit has been issued under the provisions of KRS Chapter 224 and regulations promulgated pursuant thereto. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits or licenses required by this Cabinet and other state, federal, and local agencies.

It is the responsibility of the permittee to demonstrate compliance with permit parameter limitations by utilization of sufficiently sensitive analytical methods.

PART III

OTHER REQUIREMENTS

A. Reporting of Monitoring Results

Monitoring results obtained during each month must be reported on a preprinted Discharge Monitoring Report (DMR) Form, which will be mailed to you. Each month's completed DMR must be sent to the Division of Water at the address listed below (with a copy to the appropriate Regional Office) postmarked no later than the 28th day of the month following the month for which monitoring results were obtained.

Division of Water
Morehead Regional Office
200 Christy Creek Road, Suite 2
Morehead, Kentucky 40351
ATTN: Supervisor

Kentucky Natural Resources and
Environmental Protection Cabinet
Dept. for Environmental Protection
Division of Water/KPDES Branch
14 Reilly Road, Frankfort Office Park
Frankfort, Kentucky 40601

B. Reopener Clause

This permit shall be modified, or alternatively revoked and reissued, to comply with any applicable effluent standard or limitation issued or approved under 401 KAR 5:050 through 5:080, if the effluent standard or limitation so issued or approved:

1. Contains different conditions or is otherwise more stringent than any effluent limitation in the permit; or

2. Controls any pollutant not limited in the permit.

The permit as modified or reissued under this paragraph shall also contain any other requirements of KRS Chapter 224 when applicable.

PART IV
CHRONIC CONCERNS
Biomonitoring

In accordance with PART I of this permit, the permittee shall initiate the series of tests described below within 30 days of the effective date of this permit to evaluate wastewater toxicity of the discharge from Outfall 001. If the permittee is using a more sensitive species, the initial four (4) tests shall be conducted using both test species as indicated below to provide confirmation of previously identified most sensitive test organism.

1. Test Requirements

A. The permittee shall perform one (1) short-term fathead minnow (*Pimephales promelas*) growth test and one (1) short-term daphnid (*Ceriodaphnia* sp.) life-cycle test. Tests shall be conducted with appropriate replicates of 47% effluent, a control, and a minimum of four (4) evenly spaced effluent concentrations. If the permit limit is less than 100% effluent and greater than or equal to 75% effluent, then one (1) concentration should be 100%. If the permit limit is less than 75% effluent, the permit limit concentration shall be bracketed with two (2) concentrations above and two (2) concentrations below. The selection of the effluent concentrations is subject to revision by the Division. Controls shall be tested concurrently with effluent testing using a synthetic water. The analysis will be deemed reasonable and good only if the minimum control requirements are met (i.e. $\geq$80% survival; 60% adults with 3 broods and 15 young/female for the *Ceriodaphnia* test; an average 0.25 mg weight for the minnow growth test). Any test that does not meet the control acceptability criteria shall be repeated as soon as practicable within the monitoring period (i.e. monthly or quarterly). Noncompliance with the toxicity limit will be demonstrated if the IC_{25} (inhibition concentration) for reproduction or growth is less than 47% effluent. The average reproduction for *Ceriodaphnia* shall be calculated by dividing the total number of live *Ceriodaphnia* young in each concentration by the total number of organisms used to initiate that concentration; the average growth for the fathead minnows shall be calculated by dividing the total weight of surviving minnow larvae in each replicate by the total number of organisms used to initiate that replicate.

B. Tests shall be conducted quarterly or at a frequency to be determined by the permitting authority.

A minimum of three (3) Grab samples will be collected at a frequency of one (1) sample every other day, or at a frequency to be determined by the permitting authority. For example, the first sample would be used for test initiation, day 1, and for test solution renewal on day 2. The second sample would be used for test solution renewal on days 3 and 4. The third sample would be used for test solution renewal on days 5, 6, and 7. The lapsed time from collection of the last aliquot of the composite and its first use for test initiation, or for test solution renewal shall not exceed 36 hours. Grab samples shall be iced during collection and maintained at 4° C until used.

After the first four (4) tests with both species, upon written request to the Division of Water's Bioassay Section, subsequent testing may be performed using only the most sensitive species.

2. Reporting Requirements

Results of all tests conducted with any organism shall be reported according to the most recent format provided by the Division of Water. Test results shall be submitted to the Division of Water with the next regularly scheduled discharge monitoring report.

Due to administrative and regulatory constraints regarding the requirements of Section 3 of this Part, monthly DMRs shall be submitted. Those required to conduct tests on a frequency other than monthly shall submit DMRs with "Not required this monitoring period" typed or written in the parameter row in addition to the DMR reporting the results of the test. All DMRs for Biomonitoring shall be submitted monthly regardless of required monitoring frequency.

3. Chronic Toxicity

A. If noncompliance with the toxicity limit occurs (IC_{25} for reproduction or growth is less than 47% effluent), the permittee must conduct a second test within 15 days of the first failure. This test will be used in evaluating the persistence of the toxic event and the possible need for a Toxicity Reduction Evaluation (TRE).

If the second test demonstrates noncompliance with the toxicity limit, the permittee will be required to perform either of the options listed below. The Division must be notified of the option selected within five (5) days of the failure of this second test.

1) Accelerated Testing

Complete four (4) tests within 90 days of selection of this option to evaluate the frequency and degree of toxicity. The results of the two (2) tests specified in Section 3.A and of the four (4) additional tests will be used for purposes of this evaluation.

If results from two (2) of any six (6) tests show a significant non-compliance with the chronic limit ($\geq$1.2 times the TU_c), or results from four (4) of any six (6) tests show chronic toxicity (as defined in 1.A), a Toxicity Reduction Evaluation (TRE) will be required. The Division reserves the right to require a TRE in situations of recurring toxicity.

2) Toxicity Reduction Evaluation (TRE)

If it is determined that a TRE is required, a plan and implementation schedule must be submitted to the Division within 30 days of notification. The TRE shall include appropriate measures such as in-plant controls, additional wastewater treatment, or changes in the operation of the wastewater discharge to meet permit conditions. The TRE protocol shall follow that outlined in the most recent edition of EPA's guidance for conducting TREs.

B. If a violation of the toxicity limit occurs, different or more stringent monitoring requirements may be imposed in lieu of the normal requirements of this permit for whatever period of time is specified by the Division of Water. The Division reserves the right to require additional testing or a TRE in situations of recurring toxicity.

4. Test Methods

All test organisms, procedures and quality assurance criteria used shall be in accordance with Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms (Third Edition), EPA-600-4-91-002, or the most recent edition of this publication.

PART V

BEST MANAGEMENT PRACTICES

SECTION A. GENERAL CONDITIONS

1. Applicability

These conditions apply to all permittees who use, manufacture, store, handle, or discharge any pollutant listed as: (1) toxic under Section 307(a)(1) of the Clean Water Act; (2) oil, as defined in Section 311(a)(1) of the Act; (3) any pollutant listed as hazardous under Section 311 of the Act; or (4) is defined as a pollutant pursuant to KRS 224.01-010(35) and who have ancillary manufacturing operations which could result in (1) the release of a hazardous substance, pollutant, or contaminant, or (2) an environmental emergency, as defined in KRS 224.01-400, as amended, or any regulation promulgated pursuant thereto (hereinafter, the "BMP pollutants"). These operations include material storage areas; plant site runoff; in-plant transfer, process and material handling areas; loading and unloading operations, and sludge and waste disposal areas.

2. BMP Plan

The permittee shall develop and implement a Best Management Practices (BMP) plan consistent with 401 KAR 5:065, Section 2(10) pursuant to KRS 224.70-110, which prevents or minimizes the potential for the release of "BMP pollutants" from ancillary activities through plant site runoff; spillage or leaks, sludge or waste disposal; or drainage from raw material storage. A Best Management Practices (BMP) plan will be prepared by the permittee unless the permittee can demonstrate through the submission of a BMP outline that the elements and intent of the BMP have been fulfilled through the use of existing plans such as the Spill Prevention Control and Countermeasure (SPCC) plans, contingency plans, and other applicable documents.

3. Implementation

If this is the first time for the BMP requirement, then the plan shall be developed and submitted to the Division of Water within 90 days of the effective date of the permit. Implementation shall be within 180 days of that submission. For permit renewals the plan in effect at the time of permit reissuance shall remain in effect. Modifications to the plan as a result of ineffectiveness or plan changes to the facility shall be submitted to the Division of Water and implemented as soon as possible.

4. General Requirements

The BMP plan shall:

a. Be documented in narrative form, and shall include any necessary plot plans, drawings, or maps.

b. Establish specific objectives for the control of toxic and hazardous pollutants.

   (1) Each facility component or system shall be examined for its potential for causing a release of "BMP pollutants" due to equipment failure, improper operation, natural phenomena such as rain or snowfall, etc.

(2) Where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural condition (e.g., precipitation), or other circumstances which could result in a release of "BMP pollutants," the plan should include a prediction of the direction, rate of flow, and total quantity of the pollutants which could be released from the facility as result of each condition or circumstance.

c. Establish specific Best Management Practices to meet the objectives identified under paragraph b of this section, addressing each component or system capable of causing a release of "BMP pollutants."

d. Include any special conditions established in part b of this section.

e. Be reviewed by plant engineering staff and the plant manager.

5. Specific Requirements

The plan shall be consistent with the general guidance contained in the publication entitled "NPDES Best Management Practices Guidance Document," and shall include the following baseline BMPs as a minimum.

a. BMP Committee
b. Reporting of BMP Incidents
c. Risk Identification and Assessment
d. Employee Training
e. Inspections and Records
f. Preventive Maintenance
g. Good Housekeeping
h. Materials Compatibility
i. Security
j. Materials Inventory

6. SPCC Plans

The BMP plan may reflect requirements for Spill Prevention Control and Countermeasure (SPCC) plans under Section 311 of the Act and 40 CFR Part 151, and may incorporate any part of such plans into the BMP plan by reference.

7. Hazardous Waste Management

The permittee shall assure the proper management of solid and hazardous waste in accordance with the regulations promulgated under the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1978 (RCRA) (40 U.S.C. 6901 et seq.) Management practices required under RCRA regulations shall be referenced in the BMP plan.

8. Documentation

The permittee shall maintain a description of the BMP plan at the facility and shall make the plan available upon request to NREPC personnel. Initial copies and modifications thereof shall be sent to the following addresses when required by Section 3:

Division of Water
Morehead Regional Office
200 Christy Creek Road, Suite 2
Morehead, Kentucky 40351
ATTN: Supervisor

Kentucky Natural Resources and
Environmental Protection Cabinet
Dept. for Environmental Protection
Division of Water/KPDES Branch
14 Reilly Road, Frankfort Office Park
Frankfort, Kentucky 40601

9. BMP Plan Modification

The permittee shall amend the BMP plan whenever there is a change in the facility or change in the operation of the facility which materially increases the potential for the ancillary activities to result in the release of "BMP pollutants."

10. Modification for Ineffectiveness

If the BMP plan proves to be ineffective in achieving the general objective of preventing the release of "BMP pollutants," then the specific objectives and requirements under paragraphs b and c of Section 4, the permit, and/or the BMP plan shall be subject to modification to incorporate revised BMP requirements. If at any time following the issuance of this permit the BMP plan is found to be inadequate pursuant to a state or federal site inspection or plan review, the plan shall be modified to incorporate such changes necessary to resolve the concerns.

SECTION B. SPECIFIC CONDITIONS

Periodically Discharged Wastewaters Not Specifically Covered by Effluent Conditions
The permittee shall include in this BMP plan procedures and controls necessary for the handling of periodically discharged wastewaters such as intake screen backwash, meter calibration, fire protection, hydrostatic testing water, water associated with demolition projects, etc.

KENTUCKY POWER COMPANY
BIG SANDY PLANT
LAWRENCE COUNTY, KENTUCKY

NPDES PERMIT REISSUANCE APPLICATION

PERMIT NO. KY0000221

SEPTEMBER 2005

Prepared by:

American Electric Power
Environmental Services
1 Riverside Plaza
Columbus, Ohio 43215

Big Sandy Plant NPDES Permit Renewal Application Table of Contents

KPDES FORM 1

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT APPLICATION

This is an application to: (check one)

- ☐ Apply for a new permit.
- ☒ Apply for reissuance of expiring permit.
- ☐ Apply for a construction permit.
- ☐ Modify an existing permit.
  Give reason for modification under Item II.A.

A complete application consists of this form and one of the following:
Form A, Form B, Form C, Form F, or Short Form C

For additional information contact:
KPDES Branch (502) 564-3410

I. FACILITY LOCATION AND CONTACT INFORMATION	AGENCY USE
A. Name of business, municipality, company, etc. requesting permit Kentucky Power Company	

B. Facility Name and Location	C. Facility Owner/Mailing Address
Facility Location Name: Big Sandy Plant	Owner Name: Kentucky Power Company d/b/a/ AEP, c/o Alan R. Wood
Facility Location Address (i.e. street, road, etc.): 23000 Highway 23	Mailing Street: 1 Riverside Plaza
Facility Location City, State, Zip Code: ouisa, KY 41230-8703	Mailing City, State, Zip Code: Columbus, OH 43215-2373
	Telephone Number: (614) 223-1233

II. FACILITY DESCRIPTION

A. Provide a brief description of activities, products, etc: Big Sandy Plant is a coal-fired steam electric generating facility which produces electricity. The plant consists of a 250-MW unit and an 800-MW unit.

B. Standard Industrial Classification (SIC) Code and Description			
Principal SIC Code & Description:	4911 Facility engaged in generation, transmission and/or distribution of electrical energy for sale.		
Other SIC Codes:	N/A	N/A	N/A

III. FACILITY LOCATION	
A. Attach a U.S. Geological Survey 7 ½ minute quadrangle map for the site. (See instructions)	
B. County where facility is located: Lawrence	City where facility is located (if applicable): U.S. 23, 6 miles north of Louisa, Kentucky
C. Body of water receiving discharge: Big Sandy River and Blaine Creek	
D. Facility Site Latitude (degrees, minutes, seconds): 38 degrees 10 minutes 07 seconds	Facility Site Longitude (degrees, minutes, seconds): 82 degrees 37 minutes 15 seconds
). Method used to obtain latitude & longitude (see instructions):	Survey
F. Facility Dun and Bradstreet Number (DUNS #) (if applicable):	00-486-2439

IV. OWNER/OPERATOR INFORMATION

A. Type of Ownership:
☐ Publicly Owned ☒ Privately Owned ☐ State Owned ☐ Both Public and Private Owned ☐ Federally owned

B. Operator Contact Information (See instructions)

Name of Treatment Plant Operator: Jennifer Phelps, John Skaggs, Dean Bradley, E. Doug Jones, George Waugh, Charles Stapleton, Jeffrey Hughes	Telephone Number: 606/686-2415
Operator Mailing Address (Street): 23000 Hwy 23	
Operator Mailing Address (City, State, Zip Code): Louisa, Kentucky 41230-8703	
Is the operator also the owner? Yes ☒ No ☐	Is the operator certified? If yes, list certification class and number below. Yes ☒ No ☐
Certification Class: Class I	Certification Number: 8609, 8424, 6607, 4772, 6128, 13007, 13006

V. EXISTING ENVIRONMENTAL PERMITS

Current NPDES Number: KY0000221	Issue Date of Current Permit: 04/01/2003	Expiration Date of Current Permit: 03/31/2006
Number of Times Permit Reissued: 4	Date of Original Permit Issuance: December 23, 1976	Sludge Disposal Permit Number:
Kentucky DOW Operational Permit #:	Kentucky DSMRE Permit Number(s):	

C. Which of the following additional environmental permit/registration categories will also apply to this facility?

CATEGORY	EXISTING PERMIT WITH NO.	PERMIT NEEDED WITH PLANNED APPLICATION DATE
Air Emission Source	V-97-009	
Solid or Special Waste		
Hazardous Waste - Registration or Permit	Hazardous Waste Generator EPA I.D. No. -KYD-004-862-439	

VI. DISCHARGE MONITORING REPORTS (DMRs)

KPDES permit holders are required to submit DMRs to the Division of Water on a regular schedule (as defined by the KPDES permit). The information in this section serves to specifically identify the department, office or individual you designate as responsible for submitting DMR forms to the Division of Water.

A. Name of department, office or official submitting DMRs:	M. H. Thomas, General Plant Manager
B. Address where DMR forms are to be sent. (Complete only if address is different from mailing address in Section I.)	
DMR Mailing Name:	Jennifer B. Phelps; Plant Environmental Coordinator, Senior; Big Sandy Plant
DMR Mailing Street:	23000 Highway 23
DMR Mailing City, State, Zip Code:	Louisa, Kentucky 41230-8703
DMR Official Telephone Number:	(606) 686-2415 Ext. 1316

VII. APPLICATION FILING FEE

KPDES regulations require that a permit applicant pay an application filing fee equal to twenty percent of the permit base fee. Please examine the base and filing fees listed below and in the Form 1 instructions and enclose a check payable to "Kentucky State Treasurer" for the appropriate amount. Descriptions of the base fee amounts are given in the "General Instructions."

Facility Fee Category:	Filing Fee Enclosed:
Major Industry	$640.00

VIII. CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME AND OFFICIAL TITLE (type or print):	TELEPHONE NUMBER (area code and number):
John M. McManus - Vice President Environmental Services	(614) 223-1268
SIGNATURE	DATE:
Patrick A Dalbock for John M. McManus	Sept. 27, 2005

KPDES FORM C

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT APPLICATION

A complete application consists of this form and Form 1.
For additional information, contact KPDES Branch, (502) 564-3410.

Name of Facility: Big Sandy Plant	County: Lawrence							
I. OUTFALL LOCATION	AGENCY USE							

For each outfall list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

Outfall No. (list)	LATITUDE Degrees	Minutes	Seconds	LONGITUDE Degrees	Minutes	Seconds	RECEIVING WATER (name)
001	38	11	15	82	38	00	Blaine Creek

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfall. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) all operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) the average flow contributed by each operation; and (3) the treatment received by the wastewater. Continue on additional sheets if necessary.

OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW Operation (list)	Avg/Design Flow (include units)	TREATMENT Description	List Codes from Table C-1
001	Fly Ash Pond	6.602	Mixing	1-O
			Sedimentation	1-U
			Chemical Oxidation (Natural)	2-K
			Chemical Precipitation (Natural)	X-X
			Skimming	X-X
			Discharge to Surface Water	4-A
	Sources to Fly Ash Pond:			
	Unit 1 Fly Ash Transport	0.18 MGD	All these wastestreams	
	Unit 2 Fly Ash Transport	2.392 MGD	undergo, to some degree, the	

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Outfall No. (list)	LATITUDE			LONGITUDE			RECEIVING WATER (name)
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds	
001	38	11	15	82	38	00	Blaine Creek

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfall. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) all operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) the average flow contributed by each operation; and (3) the treatment received by the wastewater. Continue on additional sheets if necessary.

OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW		TREATMENT	
	Operation (list)	Avg/Design Flow (include units)	Description	List Codes from Table C-1
001 (continued)	Unit 2 Economizer Ash Transport	0.34 MGD	treatment processes listed above	
	Reclaim Water (See Below)	3.472 MGD	for the fly ash pond.	
	Coal Pile Runoff	0.112 MGD		
	Rainfall (Avg.)	0.397 MGD		
	Sources to Reclaim Pond:			
	Unit 1 Turbine Room Sump	1.920 MGD	All these wastestreams undergo,	
	(include U-1 Cool. Twr. Blowdn)		to some degree, the treatment	
	Unit 1 Bottom Ash Transport	0.379 MGD	processes listed above for the	

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Outfall No. (list)	LATITUDE Degrees	LATITUDE Minutes	LATITUDE Seconds	LONGITUDE Degrees	LONGITUDE Minutes	LONGITUDE Seconds	RECEIVING WATER (name)
001	38	11	15	82	38	00	Blaine Creek

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

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B. For each outfall, provide a description of: (1) all operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) the average flow contributed by each operation; and (3) the treatment received by the wastewater. Continue on additional sheets if necessary.

OUTFALL NO (list)	OPERATION(S) CONTRIBUTING FLOW: Operation (list)	Avg/Design Flow (include units)	TREATMENT: Description	List Codes from Table C-1
001 (continued)	(include Unit 1 Pyrites Transport		fly ash pond and also recycle/	
	Unit 2 Bottom Ash Transport	1.05 MGD	reuse.	4-C
	(incl. Unit 2 Cool. Twr. Blowdn)			
	and Pyrites Transport			
	Unit 2 cooling Tower Blowdown	0.586 MGD		
	Unit 2 Wastewater Sump	1.920 MGD		
	Rainfall (Avg.)	0.024 MGD		

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Outfall No. (list)	LATITUDE Degrees	LATITUDE Minutes	LATITUDE Seconds	LONGITUDE Degrees	LONGITUDE Minutes	LONGITUDE Seconds	RECEIVING WATER (name)
001	38	11	15	82	38	00	Blaine Creek

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

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OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW: Operation (list)	Avg/Design Flow (include units)	TREATMENT: Description	List Codes from Table C-1
001 (continued)	Maximum Flow	16.57 MGD		
	(Includes Maximum Rainfall)			
	Fly Ash Pond Area	28.216 MGD		
	Bottom Ash Pond Area	0.794 MGD		
	Coal Pile Runoff	1.224 MGD		
	Transformer Deck Drains	0.013 MGD		

KPDES FORM C

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For each outfall list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

Outfall No. (list)	LATITUDE			LONGITUDE			RECEIVING WATER (name)
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds	
002	38	10	18	82	37	13	Bottom Ash Pond
003	38	10	18	82	37	13	Bottom Ash Pond

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

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OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW		TREATMENT	
	Operation (list)	Avg/Design Flow (include units)	Description	List Codes from Table C-1
002	Unit 1 Cooling Tower Blowdown	0.36 MGD	Mixing	1-O
			Sedimentation	1-U
			Discharge to Surface Water	4-A
003	Unit 2 Cooling Tower Blowdown	1.3 MGD	Mixing	1-O
			Sedimentation	1-U
			Discharge to Surface Water	4-A

KPDES FORM C

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Name of Facility: Big Sandy Plant	County: Lawrence							
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For each outfall list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

Outfall No. (list)	LATITUDE			LONGITUDE			RECEIVING WATER (name)
	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds	
004	38	10	08	82	37	12	Big Sandy River

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfall. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

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OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW		TREATMENT	
	Operation (list)	Avg/Design Flow (include units)	Description	List Codes from Table C-1
004	Sewage Treatment Plant	0.11 MGD	Screening	1 - T
			Activated Sludge	3 - A
			Sedimentation	1 - U
			Disinfection (chlorine)	2 - F
			Dechlorination	2 - E
			Skimming	X - X
			Discharge to surface wate	4 - A

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For each outfall list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

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	Degrees	Minutes	Seconds	Degrees	Minutes	Seconds	
005	38	10	16	82	37	19	Bottom Ash Pond

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfall. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) all operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) the average flow contributed by each operation; and (3) the treatment received by the wastewater. Continue on additional sheets if necessary.

OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW		TREATMENT	
	Operation (list)	Avg/Design Flow (include units)	Description	List Codes from Table C-1
005	Chemical Metal Cleaning Waste		Chemical Precipitation	2-C
	Supernatant (Intermittent)		Flocculation	1-G
			Sedimentation	1-U
NOTE 1:	Effluent is only discharged through	NOTE 2:	Per current KPDES permit, effl.	
	Outfall 005 after the Unit 2 chemical		analyzed for pH (12), Cu (0.006)	
	metal cleaning waste is treated. This		and Fe (0.36 mg/l) but not for	
	event occurs approx. every 5-7 years.		any other Form C parameters.	
		NOTE 3:	Part V Form C not incl. for 005.	

KPDES FORM C

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT APPLICATION

A complete application consists of this form and Form 1.
For additional information, contact KPDES Branch, (502) 564-3410.

Name of Facility: Big Sandy Plant	County: Lawrence
I. OUTFALL LOCATION	AGENCY USE

For each outfall list the latitude and longitude of its location to the nearest 15 seconds and the name of the receiving water.

Outfall No. (list)	LATITUDE Degrees	LATITUDE Minutes	LATITUDE Seconds	LONGITUDE Degrees	LONGITUDE Minutes	LONGITUDE Seconds	RECEIVING WATER (name)
018	38	11	14	82	37	55	Blaine Creek

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES

A. Attach a line drawing showing the water flow through the facility. Indicate sources of intake water, operations contributing wastewater to the effluent, and treatment units labeled to correspond to the more detailed descriptions in Item B. Construct a water balance on the line drawing by showing average flows between intakes, operations, treatment units, and outfall. If a water balance cannot be determined (e.g., for certain mining activities), provide a pictorial description of the nature and amount of any sources of water and any collection or treatment measures.

B. For each outfall, provide a description of: (1) all operations contributing wastewater to the effluent, including process wastewater, sanitary wastewater, cooling water, and storm water runoff; (2) the average flow contributed by each operation; and (3) the treatment received by the wastewater. Continue on additional sheets if necessary.

OUTFALL NO. (list)	OPERATION(S) CONTRIBUTING FLOW: Operation (list)	OPERATION(S) CONTRIBUTING FLOW: Avg/Design Flow (include units)	TREATMENT: Description	TREATMENT: List Codes from Table C-1
018	Drains Interior of Fly Ash Dam	0.13 MGD	Discharge to Surface Water	4-A
	(Coal seam seepage sump overflows			
	to Outfall 018 if sump pumps are out			
	of service.)			

II. FLOWS, SOURCES OF POLLUTION, AND TREATMENT TECHNOLOGIES (Continued)

C. Except for storm water runoff, leaks, or spills, are any of the discharges described in Items II-A or B intermittent or seasonal?

☒ Yes (Complete the following table.) ☐ No (Go to Section III.)

OUTFALL NUMBER (list)	OPERATIONS CONTRIBUTING FLOW (list)	FREQUENCY		FLOW				
		Days Per Week (specify average)	Months Per Year (specify average)	Flow Rate (in mgd)		Total volume (specify with units)		Duration (in days)
				Long-Term Average	Maximum Daily	Long-Term Average	Maximum Daily	
005	Unit 2 Chemical Metal Cleaning Waste Supernatant.	7	once per 60 - 84 months	0.560	0.080	560,000 Gallons	112,000 Gallons	7

III. MAXIMUM PRODUCTION

A. Does an effluent guideline limitation promulgated by EPA under Section 304 of the Clean Water Act apply to your facility?

☒ Yes (Complete Item III-B) List effluent guideline category:

☐ No (Go to Section IV)

B. Are the limitations in the applicable effluent guideline expressed in terms of production (or other measures of operation)?

☐ Yes (Complete Item III-C) ☒ No (Go to Section IV)

C. If you answered "Yes" to Item III-B, list the quantity which represents the actual measurement of your maximum level of production, expressed in the terms and units used in the applicable effluent guideline, and indicate the affected outfalls.

MAXIMUM QUANTITY			Affected Outfalls
Quantity Per Day	Units of Measure	Operation, Product, Material, Etc. (specify)	(list outfall numbers)

IV. IMPROVEMENTS

A. Are you now required by any federal, state or local authority to meet any implementation schedule for the construction, upgrading, or operation of wastewater equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders and grant or loan conditions.

☐ Yes (Complete the following table) ☒ No (Go to Item IV-B)

IDENTIFICATION OF CONDITION AGREEMENT, ETC.	AFFECTED OUTFALLS		BRIEF DESCRIPTION OF PROJECT	FINAL COMPLIANCE DATE	
	No.	Source of Discharge		Required	Projected

B. OPTIONAL: You may attach additional sheets describing any additional water pollution control programs (or other environmental projects which may affect your discharges) you now have under way or which you plan. Indicate whether each program is now under way or planned, and indicate your actual or planned schedules for construction.

V. INTAKE AND EFFLUENT CHARACTERISTICS

A, B, & C: See instructions before proceeding – Complete one set of tables for each outfall – Annotate the outfall number in the space provided.
NOTE: Tables V-A, V-B, and V-C are included on separate sheets numbered 5-18.

D. Use the space below to list any of the pollutants (refer to SARA Title III, Section 313) listed in Table C-3 of the instructions, which you know or have reason to believe is discharged or may be discharged from any outfall. For every pollutant you list, briefly describe the reasons you believe it to be present and report any analytical data in your possession.

POLLUTANT	SOURCE	POLLUTANT	SOURCE
Ammonia	Use in Water Treatment and pH control, and SCR and flue gas conditioning	Sodium Hydroxide	Use to regenerate demineralizer resins and for pH control and in the reverse osmosis system.
Sodium Hypochlorite	Use to control organisms that contribute to fouling problems in cooling towers and condensors.	Sodium Nitrite	Cooling water conditioner to prevent corrosion.
Ethylene Diamine-Tetracetic Acid (EDTA)	Units 1 & 2 chemical cleaning solution consists in part of this substance in diluted amounts.	Sulfuric Acid	pH control of cooling towers and regeneration of demineralizer resins

VI. POTENTIAL DISCHARGES NOT COVERED BY ANALYSIS

A. Is any pollutant listed in Item V-C a substance or a component of a substance which you use or produce, or expect to use or produce over the next 5 years as an immediate or final product or byproduct?

☐ Yes (List all such pollutants below) ☒ No (Go to Item VI-B)

B. Are your operations such that your raw materials, processes, or products can reasonably be expected to vary so that your discharge of pollutants may during the next 5 years exceed two times the maximum values reported in Item V?

☐ Yes (Complete Item VI-C) ☒ No (Go to Item VII)

C. If you answered "Yes" to Item VI-B, explain below and describe in detail to the best of your ability at this time the sources and expected levels of such pollutants which you anticipate will be discharged from each outfall over the next 5 years. Continue on additional sheets if you need more space.

VII. BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge of or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

☒ Yes (Identify the test(s) and describe their purposes below) ☐ No (Go to Section VIII)

Whole effluent toxicity testing of the Big Sandy Plant Outfall 001 effluent has been performed quarterly under the current KPDES permit. The results of quarterly testing of ceriodaphnia have all been below the permit limit.

VIII. CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in Item V performed by a contract laboratory or consulting firm?

☒ Yes (list the name, address, and telephone number of, and pollutants analyzed by each such laboratory or firm below) ☐ No (Go to Section IX)

NAME	ADDRESS	TELEPHONE (Area code & number)	POLLUTANTS ANALYZED (list)
) SGS Environmental Services, Inc.	1258 Greenbrier Street Charleston, WV 25311	(304) 346-0725	KPDES Form C Sec. V: color, bromide, surfactants, BOD, fecal coliform Part C 1V - 30V, 1A - 11A
2) AEP Dolan Environmental Laboratory	400 Bixby Road Groveport, OH 43125	(614) 836-4188	KPDES Form C Sec. V: Part A all except BOD Part B c,g,i,j,k,l, n, o and (r. - aa.) Part C, 1M - 15M
3) Big Sandy Plant Lab	23000 Hwy 23 Louis, KY 41230	(606) 686-2415 ext. 1316	temp., pH, FAC, TRO, TRC, Tot. Br., sulfite, hardness, flow

)

IX. CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME AND OFFICIAL TITLE (type or print):	TELEPHONE NUMBER (area code and number):
John M. McManus - Vice President Environmental Services	(614) 223-1268
SIGNATURE Patrick A. Oathout for John M. McManus	DATE Sept 27, 2005

KPDES FORM C
IV. B.

AEP is installing a flue gas desulfurization (FGD) system on Big Sandy Unit 2 which is 800 megawatts. FGD systems, commonly called "scrubbers," use chemical and mechanical processes to remove sulfur dioxide (SO2) from gas produced by burning coal. Exhaust gas from a coal-fired unit's steam generator is routed through absorber vessels where chemical reactions take place, and SO2 is removed.

The resulting NPDES affects from the previous mentioned environmental control addition will be addressed in a NPDES Permit Modification around 2008.

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (use the same format) instead of completing these pages. (See instructions)

V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3 of Form 2-C) — OUTFALL NO. 001

PART A – You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT: a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30 Day Value (if available) (1) Concentration	b. (2) Mass	c. Long Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	3. UNITS (specify if blank) a. Concentration	b. Mass	4. INTAKE (optional) 006 a. Long Term Avg. Value (1) Concentration	a. (2) Mass	b. No. of Analyses
a. Biochemical Oxygen Demand (BOD)	3.7						1	mg/l		<2.0		1
b. Chemical Oxygen Demand (COD)	3.0						1	mg/l		12.0		1
c. Total Organic Carbon (TOC)	2						1	mg/l		2.0		1
d. Total Suspended Solids (TSS)	33		23		10.3		28	mg/l		73.2		53
e. Ammonia (as N)	6.53				1.25		36	mg/l		<0.05		1
f. Flow (in units of MGD)	VALUE	12.13	VALUE	9.275	VALUE	6.421	59		MGD	VALUE	9.913	369
g. Temperature (winter)	VALUE		VALUE		VALUE				°C	VALUE		
h. Temperature (summer)	VALUE	25.2	VALUE		VALUE		1		°C	VALUE	27.7	1
i. pH	MINIMUM 7.28	MAXIMUM 7.92	MINIMUM	MAXIMUM			28	STANDARD UNITS				

Revised June 1999

Part B - In the MARK "X" column, place an "X" in the Believed Present column for each pollutant you know or have reason to believe is present. Place an "X" in the Believed Absent column for each pollutant you believe to be absent. If you mark the Believed Present column for any pollutant, you must provide the results of at least one analysis for that pollutant. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (if available)	2. MARK "X"		3. EFFLUENT							4. UNITS		6. INTAKE (optional)		
	a. Believed Present	b. Believed Absent	a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. Maximum 30-Day Value (if available) (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. Long-Term Avg. Value (if available) (2) Mass	d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg. Value (1) Concentration	a. Long-Term Avg. Value (2) Mass	b. No. of Analyses
a. Bromide (24959-67-9)	x		<5.0						1	mg/l		<5.0		1
b. Bromine Total Residual	x		.09						1	mg/l		0.08		1
c. Chloride	x		98						1	mg/l		11.0		1
d. Chlorine, Total Residual	x		.04						1	mg/l		0.04		1
e. Color	x		5.0						1	PCU		15		1
f. Fecal Coliform	x		160						1	c/100 ml		1400		1
g. Fluoride (16984-48-8)	x		0.7						1	mg/l		0.2		1
h. Hardness (as $CaCO_3$)	x		678						1	mg/l		185		1
i. Nitrate – Nitrite (as N)	x		4.41						1	mg/l		1.0		1
j. Nitrogen, Total Organic (as N)	x		<0.05						1	mg/l		<0.05		1
k. Oil and Grease	x		2.0		1.25		0.385		27	mg/l		<1.0		1
l. Phosphorous (as P), Total 7723-14-0	x		<0.01						1	mg/l		<0.01		1
m. Radioactivity														
(1) Alpha, Total		x												
(2) Beta, Total		x												
(3) Radium Total		x												
(4) Radium, 226, Total		x												

Part B - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
n. Sulfate (as SO_4) (14808-79-8)	x		784						1	mg/l		132		1
o. Sulfide (as S)	x		<1.0						1	mg/l		<1.0		1
p. Sulfite (as SO_4) (14286-46-3)	x		0.5						1	mg/l		1.5		1
q. Surfactants	x		<0.03						1	mg/l		<0.03		1
r. Aluminum, Total (7429-90)	x		0.12						1	mg/l		4.60		1
s. Barium, Total (7440-39-3)	x		116						1	ug/l		73		1
t. Boron, Total (7440-42-8)	x		1.96						1	mg/l		0.51		1
u. Cobalt, Total (7440-48-4)	x		4.0						1	ug/l		3.0		1
v. Iron, Total (7439-89-6)	x		0.06						1	mg/l		6.13		1
w. Magnesium Total (7439-96-4)	x		66.8						1	mg/l		21.9		1
x. Molybdenum Total (7439-98-7)	x		362						1	ug/l		<3.0		1
y. Manganese, Total (7439-96-6)	x		0.17						1	mg/l		0.24		1
z. Tin, Total (7440-31-5)	x		<5.0						1	ug/l		<5.0		1
aa. Titanium, Total (7440-32-6)	x		4.0						1	ug/l		61		1

Part C – If you are a primary industry and this outfall contains process wastewater, refer to Table C-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in the Testing Required column for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark this column (secondary industries, nonprocess wastewater outfalls, and non-required GC/MS fractions), mark "X" in the Believed Present column for each pollutant you know or have reason to believe is present. Mark "X" in the Believed Absent column for each pollutant you believe to be absent. If you mark either the Testing Required or Believed Present columns for any pollutant, you must provide the result of at least one analysis for that pollutant. Note that there are seven pages to this part; please review each carefully. Complete one table (all seven pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS															
1M. Antimony Total (7440-36-0)	x			29.0						1	ug/l		0.004		1
2M. Arsenic, Total (7440-38-2)	16x			0.094				.0.064		6	mg/l		0.018		6
3M. Beryllium Total (7440-41-7)	x			0.005				0.002		6	mg/l		0.0		6
4M. Cadmium Total (7440-43-9)	x			<0.0005				<0.0005		6	mg/l		0.0		6
5M. Chromium Total (7440-43-9)	x			0.018				0.009		6	mg/l		0.005		6
6M. Copper Total (7550-50-8)	x			0.019				0.008		6	mg/l		0.006		6
7M. Lead Total (7439-92-1)	x			0.004				0.002		6	mg/l		0.002		6
8M. Mercury Total (7439-97-6)	x			0.0035				0.001		6	ug/l		0.001		6
9M. Nickel, Total (7440-02-0)	x			0.032				0.022		6	mg/l		0.005		6
10M. Selenium, Total (7782-49-2)	x			0.035				0.027		6	mg/l		0.008		6
11M. Silver, Total (7440-28-0)	x			0.0005				0		6	mg/l		0		6

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. MARK "X" b. Believed Present	2. MARK "X" c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. EFFLUENT a. Maximum Daily Value (2) Mass	3. EFFLUENT b. Maximum 30-Day Value (if available) (1) Concentration	3. EFFLUENT b. Maximum 30-Day Value (if available) (2) Mass	3. EFFLUENT c. Long-Term Avg. Value (if available) (1) Concentration	3. EFFLUENT c. Long-Term Avg. Value (if available) (2) Mass	3. EFFLUENT d. No. of Analyses	4. UNITS a. Concentration	4. UNITS b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	5. INTAKE (optional) a. Long-Term Avg. Value (2) Mass	5. INTAKE (optional) b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS (Continued)															
12M. Thallium, Total (7440-28-0)	x			0.006				0.004		6	mg/l		0.001		6
13M. Zinc, Total (7440-66-6)	x			0.015				0.009		6	mg/l		0.008		6
14M. Cyanide, Total (57-12-5)	x			0.01						1	mg/l		<0.01		1
15M. Phenols, Total	x			<0.001						1	mg/l		<0.001		1
DIOXIN															
2,3,7,8 Tetra-chlorodibenzo, P, Dioxin (1784-01-6)			x	DESCRIBE RESULTS:											
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	x			<5.0				ug/l		1	ug/l		<5.0		1
2V. Acrylonitrile (107-13-1)	x			<5.0				ug/l		1	ug/l		<5.0		1
3V. Benzene (71-43-2)	x			<5.0				ug/l		1	ug/l		<5.0		1
5V. Bromoform (75-25-2)	x			<5.0				ug/l		1	ug/l		<5.0		1
6V. Carbon Tetrachloride (56-23-5)	x			<5.0				ug/l		1	ug/l		<5.0		1
7V. Chloro-benzene (108-90-7)	x			<5.0				ug/l		1	ug/l		<5.0		1
8V. Chlorodibro-momethane (124-48-1)	x			<5.0				ug/l		1	ug/l		<5.0		1

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. MARK "X" a. Believed Present	2. MARK "X" b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. a. Maximum Daily Value (2) Mass	3. b. Maximum 30-Day Value (if available) (1) Concentration	3. b. (2) Mass	3. c. Long-Term Avg. Value (if available) (1) Concentration	3. c. (2) Mass	3. d. No. of Analyses	4. UNITS a. Concentration	4. UNITS b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	5. a. (2) Mass	5. b. No. of Analyses
9V. Chloroethane (74-00-3)	x			<5.0						1	ug/l		<5.0		1
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	x			<5.0						1	ug/l		<5.0		1
11V. Chloroform (67-66-3)	x			<5.0						1	ug/l		<5.0		1
12V. Dichloro-bromomethane (75-71-8)	x			<5.0						1	ug/l		<5.0		1
14V. 1,1-Dichloroethane (75-34-3)	x			<5.0						1	ug/l		<5.0		1
15V. 1,2-Dichloroethane (107-06-2)	x			<5.0						1	ug/l		<5.0		1
16V. 1,1-Dichlorethylene (75-35-4)	x			<5.0						1	ug/l		<5.0		1
17V. 1,2-Di-chloropropane (78-87-5)	x			<5.0						1	ug/l		<5.0		1
18V. 1,3-Dichloropro-pylene (452-75-6)	x			<5.0						1	ug/l		<5.0		1
19V. Ethyl-benzene (100-41-4)	x			<5.0						1	ug/l		<5.0		1
20V. Methyl Bromide (74-83-9)	x			<5.0						1	ug/l		<5.0		1

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
21V. Methyl Chloride (74-87-3)	x			<5.0						1	ug/l		<5.0		1
22V. Methylene Chloride (75-00-2)	x			<5.0						1	ug/l		<5.0		1
23V. 1,1,2,2-Tetrachloro-ethane (79-34-5)	x			<5.0						1	ug/l		<5.0		1
24V. Tetrachloro-ethylene (127-18-4)	x			<5.0						1	ug/l		<5.0		1
25V. Toluene (108-88-3)	x			<5.0						1	ug/l		<5.0		1
26V. 1,2-Trans-Dichloro-ethylene (156-60-5)	x			<5.0						1	ug/l		<5.0		1
27V. 1,1,1-Tri-chloroethane (71-55-6)	x			<5.0						1	ug/l		<5.0		1
28V. 1,1,2-Tri-chloroethane (79-00-5)	x			<5.0						1	ug/l		<5.0		1
29V. Trichloro-ethylene (79-01-6)	x			<5.0						1	ug/l		<5.0		1
30V. Vinyl Chloride (75-01-4)	x			<5.0						1	ug/l		<5.0		1

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chlorophenol (95-57-8)	x			<10						1	ug/l		<10		1
2A. 2,4-Dichlor-Orophenol (120-83-2)	x			<20						1	ug/l		<20		1
3A. 2,4-Dimethylphenol (105-67-9)	x			<10						1	ug/l		<10		1
4A. 4,6-Dinitro-o-cresol (534-52-1)	x			<50						1	ug/l		<50		1
5A. 2,4-Dinitrophenol (51-28-5)	x			<50						1	ug/l		<50		1
6A. 2-Nitrophenol (88-75-5)	x			<20						1	ug/l		<20		1
7A. 4-Nitrophenol (100-02-7)	x			<50						1	ug/l		<50		1
8A. P-chloro-m-cresol (59-50-7)	x			<20						1	ug/l		<20		1
9A. Pentachlorophenol (87-88-5)	x			<50						1	ug/l		<50		1
10A. Phenol (108-05-2)	x			<10						1	ug/l		<10		1
11A. 2,4,6-Trichlorophenol (88-06-2)	x			<10						1	ug/l		<10		1
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acenaphthene (83-32-9)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
2B. Acena-phtylene (208-96-8)			x												
3B. Anthra-cene (120-12-7)			x												
4B. Benzidine (92-87-5)			x												
5B. Benzo(a)-anthracene (56-55-3)			x												
6B. Benzo(a)-pyrene (50-32-8)			x												
7B. 3,4-Benzo-fluoranthene (205-99-2)			x												
8B. Benzo(ghl) perylene (191-24-2)			x												
9B. Benzo(k)-fluoranthene (207-08-9)			x												
10B. Bis(2-chlor-octhoxy)-methane (111-91-1)			x												
11B. Bis (2-chlor-oisopropyl)-Ether			x												
12B. Bis (2-ethyl-hexyl)-phthalate (117-81-7)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
13B. 4-Bromo-phenyl Phenyl ether (101-55-3)			x												
14B. Butyl-benzyl phthalate (85-68-7)			x												
15B. 2-Chloro-naphthalene (7005-72-3)			x												
16B. 4-Chloro-phenyl phenyl ether (7005-72-3)			x												
17B. Chrysene (218-01-9)			x												
18B. Dibenzo-(a,h) Anthracene (53-70-3)			x												
19B. 1,2-Dichloro-benzene (95-50-1)			x												
20B. 1,3-Dichloro-Benzene (541-73-1)			x												
21B. 1,4-Dichloro-benzene (106-46-7)			x												
22B. 3,3-Dichloro-benzidene (91-94-1)			x												
23B. Diethyl Phthalate (84-66-2)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
24B. Dimethyl Phthalate (131-11-3)			x												
25B. Di-N-butyl Phthalate (84-74-2)			x												
26B. 2,4-Dinitro-toluene (121-14-2)			x												
27B. 2,6-Dinitro-toluene (606-20-2)			x												
28B. Di-n-octyl Phthalate (117-84-0)			x												
29B. 1,2-diphenyl-hydrazine (as azonbenzene) (122-66-7)			x												
30B. Fluoranthene (208-44-0)			x												
31B. Fluorene (86-73-7)			x												
32B. Hexachloro-benzene (118-71-1)			x												
33B. Hexachloro-butadiene (87-68-3)			x												
34B. Hexachloro-cyclopenta-diene (77-47-4)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
35B. Hexachlo-roethane (67-72-1)			x												
36B. Indneo-(1,2,3-oc)-Pyrene (193-39-5)			x												
37B. Isophorone (78-59-1)			x												
38B. Napthalene (91-20-3)			x												
39B. Nitro-benzene (98-95-3)			x												
40B. N-Nitroso-dimethyl-amine (62-75-9)			x												
41B. N-nitrosodi-n-propylamine (621-64-7)			x												
42B. N-nitro-sodiphenyl-amine (86-30-6)			x												
43B. Phenan-threne (85-01-8)			x												
44B. Pyrene (129-00-0)			x												
45B. 1,2,4 Tri-chloro-benzene (120-82-1)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. MARK "X" a. Believed Present	2. MARK "X" b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. EFFLUENT a. Maximum Daily Value (2) Mass	3. EFFLUENT b. Maximum 30-Day Value (if available) (1) Concentration	3. EFFLUENT b. Maximum 30-Day Value (if available) (2) Mass	3. EFFLUENT c. Long-Term Avg. Value (if available) (1) Concentration	3. EFFLUENT c. Long-Term Avg. Value (if available) (2) Mass	3. EFFLUENT d. No. of Analyses	4. UNITS a. Concentration	4. UNITS b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	5. INTAKE (optional) a. Long-Term Avg. Value (2) Mass	5. INTAKE (optional) b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			x												
2P. α-BHC (319-84-6)			x												
3P. β-BHC (58-89-9)			x												
4P. gamma-BHC (58-89-9)			x												
5P. δ-BHC (319-86-8)			x												
6P. Chlordane (57-74-9)			x												
7P. 4,4'-DDT (50-29-3)			x												
8P. 4,4'-DDE (72-55-9)			x												
9P. 4,4'-DDD (72-54-8)			x												
10P. Dieldrin (60-57-1)			x												
11P. α-Endosulfan (115-29-7)			x												
12P. β-Endosulfan (115-29-7)			x												
13P. Endosulfan Sulfate (1031-07-8)			x												
14P. Endrin (72-20-8)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. b. Believed Present	2. b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. a. (2) Mass	3. b. Maximum 30-Day Value (if available) (1) Concentration	3. b. (2) Mass	3. c. Long-Term Avg. Value (if available) (1) Concentration	3. c. (2) Mass	3. d. No. of Analyses	4. UNITS a. Concentration	4. b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	5. a. (2) Mass	5. b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
15P. Endrin Aldehyde (7421-93-4)			x												
16P Heptachlor (76-44-8)			x												
17P. Heptaclor Epoxide (1024-57-3)			x												
18P. PCB-1242 (53469-21-9)			x												
19P. PCB-1254 (11097-69-1)			x												
20P. PCB-1221 (11104-28-2)			x												
21P. PCB-1232 (11141-16-5)			x												
22P. PCB-1248 (12672-29-6)			x												
23P. PCB-1260 (11096-82-5)			x												
24P. PCB-1016 (12674-11-2)			x												
25P. Toxaphene (8001-35-2)			x												

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (use the same format) instead of completing these pages. (See instructions)

V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3 of Form C) — OUTFALL NO. 002

Part A – You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT: a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30 Day Value (if available) (1) Concentration	b. (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	3. UNITS (specify if blank): a. Concentration	b. Mass	4. INTAKE (optional): a. Long-Term Avg. Value (1) Concentration	a. (2) Mass	b. No. of Analyses
a. Biochemical Oxygen Demand (BOD)	<2.0						1	mg/l				
b. Chemical Oxygen Demand (COD)	41.0						1	mg/l				
c. Total Organic Carbon (TOC)	9.0						1	mg/l				
d. Total Suspended Solids (TSS)	309						1	mg/l				
e. Ammonia (as N)	<0.05						1	mg/l				
f. Flow (in units of MGD)	VALUE 0		VALUE 0		VALUE 0		14	MGD		VALUE		
g. Temperature (winter)	VALUE		VALUE		VALUE			°C		VALUE		
h. Temperature (summer)	VALUE 23.6		VALUE		VALUE		1	°C		VALUE		
i. pH	MINIMUM	MAXIMUM 8.40	MINIMUM	MAXIMUM			1	STANDARD UNITS				

Part B – In the MARK "X" column, place an "X" in the Believed Present column for each pollutant you know or have reason to believe is present. Place an "X" in the Believed Absent column for each pollutant you believe to be absent. If you mark the Believed Present column for any pollutant, you must provide the results of at least one analysis for that pollutant. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (If available)	2. MARK "X" a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
a. Bromide (24959-67-9)	x		6.0						1	mg/l				
b. Bromine Total Residual	x		0.13						1	mg/l				
c. Chloride	x		70.0						1	mg/l				
d. Chlorine, Total Residual	x		0.05						1	mg/l				
e. Color	x		30.0						1	PCU				
f. Fecal Coliform	x		800						1	c/100				
g. Fluoride (16984-48-8)	x		0.6						1	mg/l				
h. Hardness (as $CaCO_3$)	x		716.0						1	mg/l				
i. Nitrate – Nitrite (as N)	x		3.01						1	mg/l				
j. Nitrogen, Total Organic (as N)	x		0.13						1	mg/l				
k. Oil and Grease	x		1.0						1	mg/l				
l. Phosphorous (as P), Total 7723-14-0	x		0.66						1	mg/l				
m. Radioactivity														
(1) Alpha, Total		x												
(2) Beta, Total		x												
(3) Radium Total		x												
(4) Radium, 226, Total		x												

Part B - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Believed Present	b. Believed Absent	a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. Maximum 30-Day Value (if available) (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. Long-Term Avg. Value (if available) (2) Mass	d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg. Value (1) Concentration	a. Long-Term Avg. Value (2) Mass	b. No. of Analyses
n. Sulfate (as SO_4) (14808-79-8)	x		744						1	mg/l				
o. Sulfide (as S)	x		<1.0						1	mg/l				
p. Sulfite (as SO_4) (14286-46-3)	x		0.5						1	mg/l				
q. Surfactants	x		0.039						1	mg/l				
r. Aluminum, Total (7429-90)	x		8.21						1	mg/l				
s. Barium, Total (7440-39-3)	x		217						1	ug/l				
t. Boron, Total (7440-42-8)	x		<0.04						1	mg/l				
u. Cobalt, Total (7440-48-4)	x		6						1	ug/l				
v. Iron, Total (7439-89-6)	x		10.6						1	mg/l				
w. Magnesium Total (7439-96-4)	x		80.4						1	mg/l				
x. Molybdenum Total (7439-98-7)	x		<3.0						1	ug/l				
y. Manganese, Total (7439-96-6)	x		0.41						1	mg/l				
z. Tin, Total (7440-31-5)	x		6.0						1	ug/l				
aa. Titanium, Total (7440-32-6)	x		77						1	ug/l				

[illegible]

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS															
1M. Antimony Total (7440-36-0)	x			6.0						1	ug/l				
2M. Arsenic, Total (7440-38-2)	x			7.0						1	ug/l				
3M. Beryllium Total (7440-41-7)	x			0.4						1	ug/l				
4M. Cadmium Total (7440-43-9)	x			<0.5						1	ug/l				
5M. Chromium Total (7440-43-9)	x			14.0				13.5		2	ug/l				
6M. Copper Total (7550-50-8)	x			241						1	ug/l				
7M. Lead Total (7439-92-1)	x			12						1	ug/l				
8M. Mercury Total (7439-97-6)	x			<0.2						1	ug/l				
9M. Nickel, Total (7440-02-0)	x			32						1	ug/l				
10M. Selenium, Total (7782-49-2)	x			19						1	ug/l				
11M. Silver, Total (7440-28-0)	x			0.4						1	ug/l				

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30 Day Value (if available) (1) Concentration	(2) Mass	c. Long Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS (Continued)															
12M. Thallium, Total (7440-28-0)	x			<1.0						1	ug/l				
13M. Zinc, Total (7440-66-6)	x			99.0				79.0		2	ug/l				
14M. Cyanide, Total (57-12-5)	x			<0.01						1	mg/l				
15M. Phenols, Total	x			<10.0						1	ug/l				
DIOXIN															
2,3,7,8 Tetra-chlorodibenzo, P, Dioxin (1784-01-6)		x		DESCRIBE RESULTS:											
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	x			<50						1		ug/l			
2V. Acrylonitrile (107-13-1)	x			<5.0						1		ug/l			
3V. Benzene (71-43-2)	x			<5.0						1		ug/l			
5V. Bromoform (75-25-2)	x			<5.0						1		ug/l			
6V. Carbon Tetrachloride (56-23-5)	x			<5.0						1		ug/l			
7V. Chloro-benzene (108-90-7)	x			<5.0						1		ug/l			
8V. Chlorodibro-momethane (124-48-1)	x			<5.0						1		ug/l			

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. a. Believed Present	2. b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	a. (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	4. UNITS a. Concentration	4. b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	a. (2) Mass	b. No. of Analyses
9V. Chloroethane (74-00-3)	x			<5.0						1	ug/l				
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	x			<5.0						1	ug/l				
11V. Chloroform (67-66-3)	x			<5.0						1	ug/l				
12V. Dichloro-bromomethane (75-71-8)	x			<5.0						1	ug/l				
14V. 1,1-Dichloroethane (75-34-3)	x			<5.0						1	ug/l				
15V. 1,2-Dichloroethane (107-06-2)	x			<5.0						1	ug/l				
16V. 1,1-Dichlorethylene (75-35-4)	x			<5.0						1	ug/l				
17V. 1,2-Di-chloropropane (78-87-5)	x			<5.0						1	ug/l				
18V. 1,3-Dichloropro-pylene (452-75-6)	x			<5.0						1	ug/l				
19V. Ethyl-benzene (100-41-4)	x			<5.0						1	ug/l				
20V. Methyl Bromide (74-83-9)	x			<5.0						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
21V. Methyl Chloride (74-87-3)	x			<5.0						1	ug/l				
22V. Methylene Chloride (75-00-2)	x			<5.0						1	ug/l				
23V. 1,1,2,2-Tetrachloro-ethane (79-34-5)	x			<5.0						1	ug/l				
24V. Tetrachloro-ethylene (127-18-4)	x			<5.0						1	ug/l				
25V. Toluene (108-88-3)	x			<5.0						1	ug/l				
26V. 1,2-Trans-Dichloro-ethylene (156-60-5)	x			<5.0						1	ug/l				
27V. 1,1,1-Tri-chloroethane (71-55-6)	x			<5.0						1	ug/l				
28V. 1,1,2-Tri-chloroethane (79-00-5)	x			<5.0						1	ug/l				
29V. Trichloro-ethylene (79-01-6)	x			<5.0						1	ug/l				
30V. Vinyl Chloride (75-01-4)	x			<5.0						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chloro-phenol (95-57-8)	x			<10.0						1	ug/l				
2A. 2,4-Dichlor-Orophenol (120-83-2)	x			<20.0						1	ug/l				
3A. 2,4-Dimeth-ylphenol (105-67-9)	x			<10.0						1	ug/l				
4A. 4,6-Dinitro-o-cresol (534-52-1)	x			<50.0						1	ug/l				
5A. 2,4-Dinitro-phenol (51-28-5)	x			<50.0						1	ug/l				
6A. 2-Nitro-phenol (88-75-5)	x			<20.0						1	ug/l				
7A. 4-Nitro-phenol (100-02-7)	x			<50.0						1	ug/l				
8A. P-chloro-m-cresol (59-50-7)	x			<20.0						1	ug/l				
9A. Pentachloro-phenol (87-88-5)	x			<50.0						1	ug/l				
10A. Phenol (108-05-2)	x			<10.0						1	ug/l				
11A. 2,4,6-Tri-chlorophenol (88-06-2)	x			<10.0						1	ug/l				
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acena-phthene (83-32-9)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. a. Believed Present	2. b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	a. (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	4. UNITS a. Concentration	4. b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	a. (2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
2B. Acena-phtylene (208-96-8)			x												
3B. Anthra-cene (120-12-7)			x												
4B. Benzidine (92-87-5)			x												
5B. Benzo(a)-anthracene (56-55-3)			x												
6B. Benzo(a)-pyrene (50-32-8)			x												
7B. 3,4-Benzo-fluoranthene (205-99-2)			x												
8B. Benzo(ghl) perylene (191-24-2)			x												
9B. Benzo(k)-fluoranthene (207-08-9)			x												
10B. Bis(2-chlor-oethoxy)-methane (111-91-1)			x												
11B. Bis (2-chlor-oisopropyl)-Ether			x												
12B. Bis (2-ethyl-hexyl)-phthalate (117-81-7)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Testing Required	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
13B. 4-Bromo-phenyl Phenyl ether (101-55-3)			x												
14B. Butyl-benzyl phthalate (85-68-7)			x												
15B. 2-Chloro-naphthalene (7005-72-3)			x												
16B. 4-Chloro-phenyl phenyl ether (7005-72-3)			x												
17B. Chrysene (218-01-9)			x												
18B. Dibenzo-(a,h) Anthracene (53-70-3)			x												
19B. 1,2-Dichloro-benzene (95-50-1)			x												
20B. 1,3-Dichloro-Benzene (541-73-1)			x												
21B. 1,4-Dichloro-benzene (106-46-7)			x												
22B. 3,3-Dichloro-benzidene (91-94-1)			x												
23B. Diethyl Phthalate (84-66-2)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Testing Required	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
24B. Dimethyl Phthalate (131-11-3)			x												
25B. Di-N-butyl Phthalate (84-74-2)			x												
26B. 2,4-Dinitro-toluene (121-14-2)			x												
27B. 2,6-Dinitro-toluene (606-20-2)			x												
28B. Di-n-octyl Phthalate (117-84-0)			x												
29B. 1,2-diphenyl-hydrazine (as azonbenzene) (122-66-7)			x												
30B. Fluoranthene (208-44-0)			x												
31B. Fluorene (86-73-7)			x												
32B. Hexachloro-benzene (118-71-1)			x												
33B. Hexachloro-butadiene (87-68-3)			x												
34B. Hexachloro-cyclopenta-diene (77-47-4)			x												

Part C - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30 Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
35B. Hexachlo-roethane (67-72-1)			x												
36B. Indneo-(1,2,3-oc)-Pyrene (193-39-5)			x												
37B. Isophorone (78-59-1)			x												
38B. Napthalene (91-20-3)			x												
39B. Nitro-benzene (98-95-3)			x												
40B. N-Nitroso-dimethyl-amine (62-75-9)			x												
41B. N-nitrosodi-n-propylamine (621-64-7)			x												
42B. N-nitro-sodiphenyl-amine (86-30-6)			x												
43B. Phenan-threne (85-01-8)			x												
44B. Pyrene (129-00-0)			x												
45B. 1,2,4 Tri-chloro-benzene (120-82-1)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (If available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			x												
2P. α-BHC (319-84-6)			x												
3P. β-BHC (58-89-9)			x												
4P. gamma-BHC (58-89-9)			x												
5P. δ-BHC (319-86-8)			x												
6P. Chlordane (57-74-9)			x												
7P. 4,4'-DDT (50-29-3)			x												
8P. 4,4'-DDE (72-55-9)			x												
9P. 4,4'-DDD (72-54-8)			x												
10P. Dieldrin (60-57-1)			x												
11P. α-Endosulfan (115-29-7)			x												
12P. β-Endosulfan (115-29-7)			x												
13P. Endosulfan Sulfate (1031-07-8)			x												
14P. Endrin (72-20-8)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
15P. Endrin Aldehyde (7421-93-4)			x												
16P Heptachlor (76-44-8)			x												
17P. Heptaclor Epoxide (1024-57-3)			x												
18P. PCB-1242 (53469-21-9)			x												
19P. PCB-1254 (11097-69-1)			x												
20P. PCB-1221 (11104-28-2)			x												
21P. PCB-1232 (11141-16-5)			x												
22P. PCB-1248 (12672-29-6)			x												
23P. PCB-1260 (11096-82-5)			x												
24P. PCB-1016 (12674-11-2)			x												
25P. Toxaphene (8001-35-2)			x												

PLEASE PR OR TYPE IN THE UNSHADED AREAS ONLY. You may report so or all of this information on separate sheets (use the same format) instead of completing these pages. (See instructions)

V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3 of Form C) — OUTFALL NO. 003

Part A – You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT: a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	3. UNITS (specify if blank) a. Concentration	3. b. Mass	4. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	4. a. (2) Mass	4. b. No of Analyses
a. Biochemical Oxygen Demand (BOD)	2.4						1	mg/l				
b. Chemical Oxygen Demand (COD)	56.0						1	mg/l				
c. Total Organic Carbon (TOC)	15.0						1	mg/l				
d. Total Suspended Solids (TSS)	401						1	mg/l				
e. Ammonia (as N)	<0.05						1	mg/l				
f. Flow (in units of MGD)	VALUE 0		VALUE 0		VALUE 0		14	MGD		VALUE		
g. Temperature (winter)	VALUE		VALUE		VALUE			°C		VALUE		
h. Temperature (summer)	VALUE 22.7		VALUE		VALUE		1	°C		VALUE		
i. pH	MINIMUM	MAXIMUM 8.38	MINIMUM	MAXIMUM			1	STANDARD UNITS				

Revised June 1999

Part B - In the MARK "X" column, place an "X" in the Believed Present column for each pollutant you know or have reason to believe is present. Place an "X" in the Believed Absent column for each pollutant you believe to be absent. If you mark the Believed Present column for any pollutant, you must provide the results of at least one analysis for that pollutant. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (if available)	2. MARK "X"		3. EFFLUENT							4. UNITS		6. INTAKE (optional)		
	a. Believed Present	b. Believed Absent	a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. Maximum 30-Day Value (if available) (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. Long-Term Avg. Value (if available) (2) Mass	d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg Value (1) Concentration	a. Long-Term Avg Value (2) Mass	b. No. of Analyses
a. Bromide (24959-67-9)	x		9.0						1	mg/l				
b. Bromine Total Residual	x		0.13						1	mg/l				
c. Chloride	x		163.0						1	mg/l				
d. Chlorine, Total Residual	x		0.06						1	mg/l				
e. Color	x		50.0						1	PCU				
f. Fecal Coliform	x		600						1	c/100				
g. Fluoride (16984-48-8)	x		1.0						1	mg/l				
h. Hardness (as $CaCO_3$)	x		1576						1	mg/l				
i. Nitrate – Nitrite (as N)	x		6.18						1	mg/l				
j. Nitrogen, Total Organic (as N)	x		0.25						1	mg/l				
k. Oil and Grease	x		1.0						1	mg/l				
l. Phosphorous (as P), Total 7723-14-0	x		1.26						1	mg/l				
m. Radioactivity														
(1) Alpha, Total		x												
(2) Beta, Total		x												
(3) Radium Total		x												
(4) Radium, 226, Total		x												

Revised June 1999

Part B - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg. Value		b. No. of Analyses
			(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
n. Sulfate (as SO_4) (14808-79-8)	x		1860						1	mg/l				
o. Sulfide (as S)	x		<1.0						1	mg/l				
p. Sulfite (as SO_3) (14286-46-3)	x		0.25						1	mg/l				
q. Surfactants	x		0.059						1	mg/l				
r. Aluminum, Total (7429-90)	x		9.18						1	mg/l				
s. Barium, Total (7440-39-3)	x		384						1	ug/l				
t. Boron, Total (7440-42-8)	x		<0.04						1	mg/l				
u. Cobalt, Total (7440-48-4)	x		8						1	ug/l				
v. Iron, Total (7439-89-6)	x		11.2						1	mg/l				
w. Magnesium Total (7439-96-4)	x		164						1	mg/l				
x. Molybdenum Total (7439-98-7)	x		<3.0						1	ug/l				
y. Manganese, Total (7439-96-6)	x		0.43						1	mg/l				
z. Tin, Total (7440-31-5)	x		<5.0						1	ug/l				
aa. Titanium, Total (7440-32-6)	x		74						1	ug/l				

PART C - If you are a primary industry and this outfall contains process wastewater, refer to Table 2C-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in column 2-a for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark column 2-a (secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions), mark "X" in column 2-b for each pollutant you know or have reason to believe is present. Mark "X" in column 2-c for each pollutant you believe is absent. If you mark column 2a for any pollutant, you must provide the results of at least one analysis for that pollutant. If you mark column 2b for any pollutant, you must provide the results of at least one analysis for that pollutant if you know or have reason to believe it will be discharged in concentrations of 10 ppb or greater. Note that there are seven pages to this part; please review each carefully. Complete one table (all seven pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (if available)	2. MARK "X": a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT: a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS: a. Concentration	b. Mass	5. INTAKE (optional): a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS															
1M. Antimony Total (7440-36-0)	x			9.0						1	ug/l				
2M. Arsenic, Total (7440-38-2)	x			14						1	ug/l				
3M. Beryllium Total (7440-41-7)	x			0.4						1	ug/l				
4M. Cadmium Total (7440-43-9)	x			<0.5						1	ug/l				
5M. Chromium Total (7440-43-9)	x			15.0				14.0		2	ug/l				
6M. Copper Total (7550-50-8)	x			45						1	ug/l				
7M. Lead Total (7439-92-1)	x			14						1	ug/l				
8M. Mercury Total (7439-97-6)	x			<0.2						1	ug/l				
9M. Nickel, Total (7440-02-0)	x			22						1	ug/l				
10M. Selenium, Total (7782-49-2)	x			15						1	ug/l				
11M. Silver, Total (7440-28-0)	x			0.5						1	ug/l				

PART C - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS (Continued)															
12M. Thallium, Total (7440-28-0)	x			<1.0						1	ug/l				
13M. Zinc, Total (7440-66-6)	x			61				57.5		2	ug/l				
14M. Cyanide, Total (57-12-5)	x			0.01						1	mg/l				
15M. Phenols, Total	x			<10.0						1	ug/l				
DIOXIN															
2,3,7,8 Tetra-chlorodibenzo, P, Dioxin (1784-01-6)		x		DESCRIBE RESULTS:											
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	x			<50						1		ug/l			
2V. Acrylonitrile (107-13-1)	x			<5.0						1		ug/l			
3V. Benzene (71-43-2)	x			<5.0						1		ug/l			
5V. Bromoform (75-25-2)	x			<5.0						1		ug/l			
6V. Carbon Tetrachloride (56-23-5)	x			<5.0						1		ug/l			
7V. Chloro-benzene (108-90-7)	x			<5.0						1		ug/l			
8V. Chlorodibro-momethane (124-48-1)	x			<5.0						1		ug/l			

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
9V. Chloroethane (74-00-3)	x			<5.0						1	ug/l				
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	x			<5.0						1	ug/l				
11V. Chloroform (67-66-3)	x			<5.0						1	ug/l				
12V. Dichloro-bromomethane (75-71-8)	x			<5.0						1	ug/l				
14V. 1,1-Dichloroethane (75-34-3)	x			<5.0						1	ug/l				
15V. 1,2-Dichloroethane (107-06-2)	x			<5.0						1	ug/l				
16V. 1,1-Dichlorethylene (75-35-4)	x			<5.0						1	ug/l				
17V. 1,2-Di-chloropropane (78-87-5)	x			<5.0						1	ug/l				
18V. 1,3-Dichloropro-pylene (452-75-6)	x			<5.0						1	ug/l				
19V. Ethyl-benzene (100-41-4)	x			<5.0						1	ug/l				
20V. Methyl Bromide (74-83-9)	x			<5.0						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
21V. Methyl Chloride (74-87-3)	x			<5.0						1	ug/l				
22V. Methylene Chloride (75-00-2)	x			<5.0						1	ug/l				
23V. 1,1,2,2-Tetrachloro-ethane (79-34-5)	x			<5.0						1	ug/l				
24V. Tetrachloro-ethylene (127-18-4)	x			<5.0						1	ug/l				
25V. Toluene (108-88-3)	x			<5.0						1	ug/l				
26V. 1,2-Trans-Dichloro-ethylene (156-60-5)	x			<5.0						1	ug/l				
27V. 1,1,1-Tri-chloroethane (71-55-6)	x			<5.0						1	ug/l				
28V. 1,1,2-Tri-chloroethane (79-00-5)	x			<5.0						1	ug/l				
29V. Trichloro-ethylene (79-01-6)	x			<5.0						1	ug/l				
30V. Vinyl Chloride (75-01-4)	x			<5.0						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. MARK "X" a. Believed Present	2. MARK "X" b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. EFFLUENT a. Maximum Daily Value (2) Mass	3. EFFLUENT b. Maximum 30-Day Value (if available) (1) Concentration	3. EFFLUENT b. Maximum 30-Day Value (if available) (2) Mass	3. EFFLUENT c. Long-Term Avg. Value (if available) (1) Concentration	3. EFFLUENT c. Long-Term Avg. Value (if available) (2) Mass	3. EFFLUENT d. No. of Analyses	4. UNITS a. Concentration	4. UNITS b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	5. INTAKE (optional) a. Long-Term Avg Value (2) Mass	5. INTAKE (optional) b. No. of Analyses
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chloro-phenol (95-57-8)	x			<10.0						1	ug/l				
2A. 2,4-Dichlor-Orophenol (120-83-2)	x			<20.0						1	ug/l				
3A. 2,4-Dimeth-ylphenol (105-67-9)	x			<10.0						1	ug/l				
4A. 4,6-Dinitro-o-cresol (534-52-1)	x			<50.0						1	ug/l				
5A. 2,4-Dinitro-phenol (51-28-5)	x			<50.0						1	ug/l				
6A. 2-Nitro-phenol (88-75-5)	x			<20.0						1	ug/l				
7A. 4-Nitro-phenol (100-02-7)	x			<50.0						1	ug/l				
8A. P-chloro-m-cresol (59-50-7)	x			<20.0						1	ug/l				
9A. Pentachloro-phenol (87-88-5)	x			<50.0						1	ug/l				
10A. Phenol (108-05-2)	x			<10.0						1	ug/l				
11A. 2,4,6-Tri-chlorophenol (88-06-2)	x			<10.0						1	ug/l				
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acena-phthene (83-32-9)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. b. Believed Present	2. b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. a. (2) Mass	3. b. Maximum 30-Day Value (if available) (1) Concentration	3. b. (2) Mass	3. c. Long-Term Avg. Value (if available) (1) Concentration	3. c. (2) Mass	3. d. No. of Analyses	4. UNITS a. Concentration	4. b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	5. a. (2) Mass	5. b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
2B. Acena-phtylene (208-96-8)			x												
3B. Anthra-cene (120-12-7)			x												
4B. Benzidine (92-87-5)			x												
5B. Benzo(a)-anthracene (56-55-3)			x												
6B. Benzo(a)-pyrene (50-32-8)			x												
7B. 3,4-Benzo-fluoranthene (205-99-2)			x												
8B. Benzo(ghl) perylene (191-24-2)			x												
9B. Benzo(k)-fluoranthene (207-08-9)			x												
10B. Bis(2-chlor-oethoxy)-methane (111-91-1)			x												
11B. Bis (2-chlor-oisopropyl)-Ether			x												
12B. Bis (2-ethyl-hexyl)-phthalate (117-81-7)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Testing Required	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
13B. 4-Bromo-phenyl Phenyl ether (101-55-3)			x												
14B. Butyl-benzyl phthalate (85-68-7)			x												
15B. 2-Chloro-naphthalene (7005-72-3)			x												
16B. 4-Chloro-phenyl phenyl ether (7005-72-3)			x												
17B. Chrysene (218-01-9)			x												
18B. Dibenzo-(a,h) Anthracene (53-70-3)			x												
19B. 1,2-Dichloro-benzene (95-50-1)			x												
20B. 1,3-Dichloro-Benzene (541-73-1)			x												
21B. 1,4-Dichloro-benzene (106-46-7)			x												
22B. 3,3-Dichloro-benzidene (91-94-1)			x												
23B. Diethyl Phthalate (84-66-2)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Testing Required	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg. Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
24B. Dimethyl Phthalate (131-11-3)			x												
25B. Di-N-butyl Phthalate (84-74-2)			x												
26B. 2,4-Dinitro-toluene (121-14-2)			x												
27B. 2,6-Dinitro-toluene (606-20-2)			x												
28B. Di-n-octyl Phthalate (117-84-0)			x												
29B. 1,2-diphenyl-hydrazine (as azonbenzene) (122-66-7)			x												
30B. Fluoranthene (208-44-0)			x												
31B. Fluorene (86-73-7)			x												
32B. Hexachloro-benzene (118-71-1)			x												
33B. Hexachloro-butadiene (87-68-3)			x												
34B. Hexachloro-cyclopenta-diene (77-47-4)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
35B. Hexachlo-roethane (67-72-1)			x												
36B. Indneo-(1,2,3-oc)-Pyrene (193-39-5)			x												
37B. Isophorone (78-59-1)			x												
38B. Napthalene (91-20-3)			x												
39B. Nitro-benzene (98-95-3)			x												
40B. N-Nitroso-dimethyl-amine (62-75-9)			x												
41B. N-nitrosodi-n-propylamine (621-64-7)			x												
42B. N-nitro-sodiphenyl-amine (86-30-6)			x												
43B. Phenan-threne (85-01-8)			x												
44B. Pyrene (129-00-0)			x												
45B. 1,2,4 Tri-chloro-benzene (120-82-1)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. MARK "X" a. Believed Present	2. MARK "X" b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. EFFLUENT a. Maximum Daily Value (2) Mass	3. EFFLUENT b. Maximum 30-Day Value (if available) (1) Concentration	3. EFFLUENT b. Maximum 30-Day Value (if available) (2) Mass	3. EFFLUENT c. Long-Term Avg. Value (if available) (1) Concentration	3. EFFLUENT c. Long-Term Avg. Value (if available) (2) Mass	3. EFFLUENT d. No. of Analyses	4. UNITS a. Concentration	4. UNITS b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	5. INTAKE (optional) a. Long-Term Avg. Value (2) Mass	5. INTAKE (optional) b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			x												
2P. α-BHC (319-84-6)			x												
3P. β-BHC (58-89-9)			x												
4P. gamma-BHC (58-89-9)			x												
5P. δ-BHC (319-86-8)			x												
6P. Chlordane (57-74-9)			x												
7P. 4,4'-DDT (50-29-3)			x												
8P. 4,4'-DDE (72-55-9)			x												
9P. 4,4'-DDD (72-54-8)			x												
10P. Dieldrin (60-57-1)			x												
11P. α-Endosulfan (115-29-7)			x												
12P. β-Endosulfan (115-29-7)			x												
13P. Endosulfan Sulfate (1031-07-8)			x												
14P. Endrin (72-20-8)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	b. Believed Present	c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
15P. Endrin Aldehyde (7421-93-4)			x												
16P Heptachlor (76-44-8)			x												
17P. Heptaclor Epoxide (1024-57-3)			x												
18P. PCB-1242 (53469-21-9)			x												
19P. PCB-1254 (11097-69-1)			x												
20P. PCB-1221 (11104-28-2)			x												
21P. PCB-1232 (11141-16-5)			x												
22P. PCB-1248 (12672-29-6)			x												
23P. PCB-1260 (11096-82-5)			x												
24P. PCB-1016 (12674-11-2)			x												
25P. Toxaphene (8001-35-2)			x												

PLEASE PRINT OR TYPE IN THE UNSHADED AREAS ONLY. You may report some or all of this information on separate sheets (use the same format) instead of completing these pages. (See instructions)

V. INTAKE AND EFFLUENT CHARACTERISTICS (Continued from page 3 of Form C) — OUTFALL NO. 002

Part A – You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

1. POLLUTANT	2. EFFLUENT: a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	3. UNITS (specify if blank): a. Concentration	3. b. Mass	4. INTAKE (optional): a. Long-Term Avg. Value (1) Concentration	4. a. (2) Mass	4. b. No of Analyses
a. Biochemical Oxygen Demand (BOD)	47		31		12.15		15	mg/l				
b. Chemical Oxygen Demand (COD)	49						1	mg/l				
c. Total Organic Carbon (TOC)	11						1	mg/l				
d. Total Suspended Solids (TSS)	25		25		9.23		14	mg/l				
e. Ammonia (as N)	2		2		0.23		14	mg/l				
f. Flow (in units of MGD)	VALUE 0.10		VALUE 0.1		VALUE 0.015		15	MGD		VALUE		
g. Temperature (winter)	VALUE		VALUE		VALUE			°C		VALUE		
h. Temperature (summer)	VALUE 22.9		VALUE		VALUE		1	°C		VALUE		
i. pH	MINIMUM	MAXIMUM 7.47	MINIMUM	MAXIMUM			1	STANDARD UNITS				

PART B – In the MARK "X" column, place an "X" in the Believed Present column for each pollutant you know or have reason to believe is present. Place an "X" in the Believed Absent column for each pollutant you believe to be absent. If you mark the Believed Present column for any pollutant, you must provide the results of at least one analysis for that pollutant. Complete one table for each outfall. See the instructions for additional details and requirements.

1. POLLUTANT AND CAS NO. (if available)	2. MARK "X" a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
a. Bromide (24959-67-9)	x		<5.0						1	mg/l				
b. Bromine Total Residual	x		0.09						1	mg/l				
c. Chloride	x		131						1	mg/l				
d. Chlorine, Total Residual	x		0.05				0.004		15	mg/l				
e. Color	x		10						1	PCU				
f. Fecal Coliform	x		430		150		25.8		15	c/100				
g. Fluoride (16984-48-8)	x		0.9						1	mg/l				
h. Hardness (as $CaCO_3$)	x		258						1	mg/l				
i. Nitrate – Nitrite (as N)	x		25.8						1	mg/l				
j. Nitrogen, Total Organic (as N)	x		<0.05						1	mg/l				
k. Oil and Grease	x		8						1	mg/l				
l. Phosphorous (as P), Total 7723-14-0	x		3.36						1	mg/l				
m. Radioactivity														
(1) Alpha, Total		x												
(2) Beta, Total		x												
(3) Radium Total		x												
(4) Radium, 226, Total		x												

Part B - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"		3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Believed Present	b. Believed Absent	a. Maximum Daily Value (1) Concentration	a. Maximum Daily Value (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. Maximum 30-Day Value (if available) (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. Long-Term Avg. Value (if available) (2) Mass	d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg. Value (1) Concentration	a. Long-Term Avg. Value (2) Mass	b. No. of Analyses
n. Sulfate (as SO_4) (14808-79-8)	x		216						1	mg/l				
o. Sulfide (as S)	x		<1.0						1	mg/l				
p. Sulfite (as SO_4) (14286-46-3)	x		1.0						1	mg/l				
q. Surfactants	x		<0.03						1	mg/l				
r. Aluminum, Total (7429-90)	x		0.36						1	mg/l				
s. Barium, Total (7440-39-3)	x		20						1	ug/l				
t. Boron, Total (7440-42-8)	x		<0.04						1	mg/l				
u. Cobalt, Total (7440-48-4)	x		<2						1	ug/l				
v. Iron, Total (7439-89-6)	x		0.07						1	mg/l				
w. Magnesium Total (7439-96-4)	x		25.3						1	mg/l				
x. Molybdenum Total (7439-98-7)	x		17						1	ug/l				
y. Manganese, Total (7439-96-6)	x		<0.01						1	mg/l				
z. Tin, Total (7440-31-5)	x		<5						1	ug/l				
aa. Titanium, Total (7440-32-6)	x		<2.0						1	ug/l				

Part C – If you are a primary industry and this outfall contains process wastewater, refer to Table C-2 in the instructions to determine which of the GC/MS fractions you must test for. Mark "X" in the Testing Required column for all such GC/MS fractions that apply to your industry and for ALL toxic metals, cyanides, and total phenols. If you are not required to mark this column (secondary industries, nonprocess wastewater outfalls, and nonrequired GC/MS fractions), mark "X" in the Believed Present column for each pollutant you know or have reason to believe is present. Mark "X" in the Believed Absent column for each pollutant you believe to be absent. If you mark either the Testing Required or Believed Present columns for any pollutant, you must provide the result of at least one analysis for that pollutant. Note that there are seven pages to this part; please review each carefully. Complete one table (all seven pages) for each outfall. See instructions for additional details and requirements.

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Testing Required	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
METALS, CYANIDE AND TOTAL PHENOLS															
1M. Antimony Total (7440-36-0)	x			<5.0						1	ug/l				
2M. Arsenic, Total (7440-38-2)	x			<4.0						1	ug/l				
3M. Beryllium Total (7440-41-7)	x			<0.2						1	ug/l				
4M. Cadmium Total (7440-43-9)	x			<0.5						1	ug/l				
5M. Chromium Total (7440-43-9)	x			3.0						1	ug/l				
6M. Copper Total (7550-50-8)	x			18						1	ug/l				
7M. Lead Total (7439-92-1)	x			4.0						1	ug/l				
8M. Mercury Total (7439-97-6)	x			<0.2						1	ug/l				
9M. Nickel, Total (7440-02-0)	x			<3.0						1	ug/l				
10M. Selenium, Total (7782-49-2)	x			13						1	ug/l				
11M. Silver, Total (7440-28-0)	x			0.2						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
METALS, CYANIDE AND TOTAL PHENOLS (Continued)															
12M. Thallium, Total (7440-28-0)	x			<1.0						1	ug/l				
13M. Zinc, Total (7440-66-6)	x			25						1	ug/l				
14M. Cyanide, Total (57-12-5)	x			<0.01						1	mg/l				
15M. Phenols, Total	x			<10.0						1	ug/l				
DIOXIN															
2,3,7,8 Tetra-chlorodibenzo, P, Dioxin (1784-01-6)			x	DESCRIBE RESULTS:											
GC/MS FRACTION – VOLATILE COMPOUNDS															
1V. Acrolein (107-02-8)	x			<50						1		ug/l			
2V. Acrylonitrile (107-13-1)	x			<5.0						1		ug/l			
3V. Benzene (71-43-2)	x			<5.0						1		ug/l			
5V. Bromoform (75-25-2)	x			<5.0						1		ug/l			
6V. Carbon Tetrachloride (56-23-5)	x			<5.0						.1		ug/l			
7V. Chloro-benzene (108-90-7)	x			<5.0						1		ug/l			
8V. Chlorodibro-momethane (124-48-1)	x			<5.0						1		ug/l			

Part C - Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. a. Believed Present	2. b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	a. (2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	b. (2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	c. (2) Mass	d. No. of Analyses	4. UNITS a. Concentration	4. b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	a. (2) Mass	b. No. of Analyses
9V. Chloroethane (74-00-3)	x			<5.0						1	ug/l				
10V. 2-Chloro-ethylvinyl Ether (110-75-8)	x			<5.0						1	ug/l				
11V. Chloroform (67-66-3)	x			47						1	ug/l				
12V. Dichloro-bromomethane (75-71-8)	x			11.0						1	ug/l				
14V. 1,1-Dichloroethane (75-34-3)	x			<5.0						1	ug/l				
15V. 1,2-Dichloroethane (107-06-2)	x			<5.0						1	ug/l				
16V. 1,1-Dichlorethylene (75-35-4)	x			<5.0						1	ug/l				
17V. 1,2-Di-chloropropane (78-87-5)	x			<5.0						1	ug/l				
18V. 1,3-Dichloropro-pylene (452-75-6)	x			<5.0						1	ug/l				
19V. Ethyl-benzene (100-41-4)	x			<5.0						1	ug/l				
20V. Methyl Bromide (74-83-9)	x			<5.0						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
21V. Methyl Chloride (74-87-3)	x			<5.0						1	ug/l				
22V. Methylene Chloride (75-00-2)	x			<5.0						1	ug/l				
23V. 1,1,2,2-Tetrachloro-ethane (79-34-5)	x			<5.0						1	ug/l				
24V. Tetrachloro-ethylene (127-18-4)	x			<5.0						1	ug/l				
25V. Toluene (108-88-3)	x			<5.0						1	ug/l				
26V. 1,2-Trans-Dichloro-ethylene (156-60-5)	x			<5.0						1	ug/l				
27V. 1,1,1-Tri-chloroethane (71-55-6)	x			<5.0						1	ug/l				
28V. 1,1,2-Tri-chloroethane (79-00-5)	x			<5.0						1	ug/l				
29V. Trichloro-ethylene (79-01-6)	x			<5.0						1	ug/l				
30V. Vinyl Chloride (75-01-4)	x			<5.0						1	ug/l				

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – ACID COMPOUNDS															
1A. 2-Chloro-phenol (95-57-8)	x			<10.0						1	ug/l				
2A. 2,4-Dichlor-Orophenol (120-83-2)	x			<20.0						1	ug/l				
3A. 2,4-Dimeth-ylphenol (105-67-9)	x			<10.0						1	ug/l				
4A. 4,6-Dinitro-o-cresol (534-52-1)	x			<50.0						1	ug/l				
5A. 2,4-Dinitro-phenol (51-28-5)	x			<50.0						1	ug/l				
6A. 2-Nitro-phenol (88-75-5)	x			<20.0						1	ug/l				
7A. 4-Nitro-phenol (100-02-7)	x			<50.0						1	ug/l				
8A. P-chloro-m-cresol (59-50-7)	x			<20.0						1	ug/l				
9A. Pentachloro-phenol (87-88-5)	x			<50.0						1	ug/l				
10A. Phenol (108-05-2)	x			<10.0						1	ug/l				
11A. 2,4,6-Tri-chlorophenol (88-06-2)	x			<10.0						1	ug/l				
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS															
1B. Acena-phthene (83-32-9)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X"			3. EFFLUENT							4. UNITS		5. INTAKE (optional)		
	a. Testing Required	a. Believed Present	b. Believed Absent	a. Maximum Daily Value		b. Maximum 30-Day Value (if available)		c. Long-Term Avg. Value (if available)		d. No. of Analyses	a. Concentration	b. Mass	a. Long-Term Avg Value		b. No. of Analyses
				(1) Concentration	(2) Mass	(1) Concentration	(2) Mass	(1) Concentration	(2) Mass				(1) Concentration	(2) Mass	
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
2B. Acenaphtylene (208-96-8)			x												
3B. Anthracene (120-12-7)			x												
4B. Benzidine (92-87-5)			x												
5B. Benzo(a)-anthracene (56-55-3)			x												
6B. Benzo(a)-pyrene (50-32-8)			x												
7B. 3,4-Benzo-fluoranthene (205-99-2)			x												
8B. Benzo(ghl) perylene (191-24-2)			x												
9B. Benzo(k)-fluoranthene (207-08-9)			x												
10B. Bis(2-chlor-oethoxy)-methane (111-91-1)			x												
11B. Bis (2-chlor-oisopropyl)-Ether			x												
12B. Bis (2-ethyl-hexyl)-phthalate (117-81-7)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK 'X' a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
13B. 4-Bromo-phenyl Phenyl ether (101-55-3)			x												
14B. Butyl-benzyl phthalate (85-68-7)			x												
15B. 2-Chloro-naphthalene (7005-72-3)			x												
16B. 4-Chloro-phenyl phenyl ether (7005-72-3)			x												
17B. Chrysene (218-01-9)			x												
18B. Dibenzo-(a,h) Anthracene (53-70-3)			x												
19B. 1,2-Dichloro-benzene (95-50-1)			x												
20B. 1,3-Dichloro-Benzene (541-73-1)			x												
21B. 1,4-Dichloro-benzene (106-46-7)			x												
22B. 3,3-Dichloro-benzidene (91-94-1)			x												
23B. Diethyl Phthalate (84-66-2)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
24B. Dimethyl Phthalate (131-11-3)			x												
25B. Di-N-butyl Phthalate (84-74-2)			x												
26B. 2,4-Dinitro-toluene (121-14-2)			x												
27B. 2,6-Dinitro-toluene (606-20-2)			x												
28B. Di-n-octyl Phthalate (117-84-0)			x												
29B. 1,2-diphenyl-hydrazine (as azonbenzene) (122-66-7)			x												
30B. Fluoranthene (208-44-0)			x												
31B. Fluorene (86-73-7)			x												
32B. Hexachloro-benzene (118-71-1)			x												
33B. Hexachloro-butadiene (87-68-3)			x												
34B. Hexachloro-cyclopenta-diene (77-47-4)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – BASE/NEUTRAL COMPOUNDS (Continued)															
35B. Hexachlo-roethane (67-72-1)			x												
36B. Indneo-(1,2,3-oc)-Pyrene (193-39-5)			x												
37B. Isophorone (78-59-1)			x												
38B. Napthalene (91-20-3)			x												
39B. Nitro-benzene (98-95-3)			x												
40B. N-Nitroso-dimethyl-amine (62-75-9)			x												
41B. N-nitrosodi-n-propylamine (621-64-7)			x												
42B. N-nitro-sodiphenyl-amine (86-30-6)			x												
43B. Phenan-threne (85-01-8)			x												
44B. Pyrene (129-00-0)			x												
45B. 1,2,4 Tri-chloro-benzene (120-82-1)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK 'X' a. Testing Required	a. Believed Present	b. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	(2) Mass	b. Maximum 30-Day Value (if available) (1) Concentration	(2) Mass	c. Long-Term Avg. Value (if available) (1) Concentration	(2) Mass	d. No. of Analyses	4. UNITS a. Concentration	b. Mass	5. INTAKE (optional) a. Long-Term Avg. Value (1) Concentration	(2) Mass	b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
1P. Aldrin (309-00-2)			x												
2P. α-BHC (319-84-6)			x												
3P. β-BHC (58-89-9)			x												
4P. gamma-BHC (58-89-9)			x												
5P. δ-BHC (319-86-8)			x												
6P. Chlordane (57-74-9)			x												
7P. 4,4'-DDT (50-29-3)			x												
8P. 4,4'-DDE (72-55-9)			x												
9P. 4,4'-DDD (72-54-8)			x												
10P. Dieldrin (60-57-1)			x												
11P. α-Endosulfan (115-29-7)			x												
12P. β-Endosulfan (115-29-7)			x												
13P. Endosulfan Sulfate (1031-07-8)			x												
14P. Endrin (72-20-8)			x												

Part C – Continued

1. POLLUTANT And CAS NO. (if available)	2. MARK "X" a. Testing Required	2. b. Believed Present	2. c. Believed Absent	3. EFFLUENT a. Maximum Daily Value (1) Concentration	3. a. (2) Mass	3. b. Maximum 30-Day Value (if available) (1) Concentration	3. b. (2) Mass	3. c. Long-Term Avg. Value (if available) (1) Concentration	3. c. (2) Mass	3. d. No. of Analyses	4. UNITS a. Concentration	4. b. Mass	5. INTAKE (optional) a. Long-Term Avg Value (1) Concentration	5. a. (2) Mass	5. b. No. of Analyses
GC/MS FRACTION – PESTICIDES															
15P. Endrin Aldehyde (7421-93-4)			x												
16P Heptachlor (76-44-8)			x												
17P. Heptaclor Epoxide (1024-57-3)			x												
18P. PCB-1242 (53469-21-9)			x												
19P. PCB-1254 (11097-69-1)			x												
20P. PCB-1221 (11104-28-2)			x												
21P. PCB-1232 (11141-16-5)			x												
22P. PCB-1248 (12672-29-6)			x												
23P. PCB-1260 (11096-82-5)			x												
24P. PCB-1016 (12674-11-2)			x												
25P. Toxaphene (8001-35-2)			x												

KPDES FORM F

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT APPLICATION

A complete application consists of this form and Form 1.
For additional information, Contact KPDES Branch, (502) 564-3410.

I. OUTFALL LOCATION

AGENCY USE

For each outfall list the latitude and longitude of its location to the nearest 15 seconds and name the receiving water.

A. Outfall Number	B. Latitude			C. Longitude			D. Receiving Water (name)
007	38	10	09	82	37	03	Big Sandy River
008	38	10	12	82	36	50	Big Sandy River
009	38	10	31	82	36	40	Big Sandy River
010	38	10	24	82	36	39	Big Sandy River
011	38	10	18	82	36	41	Big Sandy River

II. IMPROVEMENTS

A. Are you now required by any federal, state, or local authority to meet any implementaiton schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

1. Identification of Conditions, Agreements, Etc.	2. Affected Outfalls No.	Source of Discharge	3. Brief Description of Project	4. Final Compliance Date a. req.	b. proj.
N/A	N/A	N/A	N/A	N/A	N/A

B. You may attach additional sheets describing any additional water pollution (or other environmental projects which may affect your discharges) you now have under way or which you plan. Indicate whether each program is now under way or planned, and indicate your actual or planned schedules for construction.

III. SITE DRAINAGE MAP

Attach a site map showing topography (or indicating the outline of drainage areas served by the outfall(s) covered in the application if a topographic map is unavailable) depicting the facility including: each of its intake and discharge structures; the drainage area of each storm water outfall; paved areas and buildings within the drainage area of each storm water outfall, each know past or present areas used for outdoor storage or disposal of significant materials, each existing structural control measure to reduce pollutants in storm water runoff, materials loading and access areas, areas where pesticides, herbicides, soil conditioners and fertilizers are applied; each of its hazardous waste treatment, storage of disposal units (including each area not required to have a RCRA permit which is used for accumulating hazardous waste under 40 CFR 262.34); each well where fluids from the facility are injected underground; springs, and other surface water bodies which receive storm water discharges from the facility.

KPDES FORM F

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT APPLICATION

A complete application consists of this form and Form 1.
For additional information, Contact KPDES Branch, (502) 564-3410.

I. OUTFALL LOCATION

AGENCY USE

For each outfall list the latitude and longitude of its location to the nearest 15 seconds and name the receiving water.

A. Outfall Number	B. Latitude			C. Longitude			D. Receiving Water (name)
012	38	10	14	82	36	46	Big Sandy River
013	38	10	11	82	36	54	Big Sandy River
014	38	10	10	82	36	58	Big Sandy River
015	38	10	09	82	37	00	Big Sandy River
016	38	10	08	82	37	09	Big Sandy River

II. IMPROVEMENTS

A. Are you now required by any federal, state, or local authority to meet any implementaiton schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

1. Identification of Conditions, Agreements, Etc.	2. Affected Outfalls No.	Source of Discharge	3. Brief Description of Project	4. Final Compliance Date a. req.	b. proj.
N/A	N/A	N/A	N/A	N/A	N/A

B. You may attach additional sheets describing any additional water pollution (or other environmental projects which may affect your discharges) you now have under way or which you plan. Indicate whether each program is now under way or planned, and indicate your actual or planned schedules for construction.

III. SITE DRAINAGE MAP

Attach a site map showing topography (or indicating the outline of drainage areas served by the outfall(s) covered in the application if a topographic map is unavailable) depicting the facility including: each of its intake and discharge structures; the drainage area of each storm water outfall; paved areas and buildings within the drainage area of each storm water outfall, each know past or present areas used for outdoor storage or disposal of significant materials, each existing structural control measure to reduce pollutants in storm water runoff, materials loading and access areas, areas where pesticides, herbicides, soil conditioners and fertilizers are applied; each of its hazardous waste treatment, storage of disposal units (including each area not required to have a RCRA permit which is used for accumulating hazardous waste under 40 CFR 262.34); each well where fluids from the facility are injected underground; springs, and other surface water bodies which receive storm water discharges from the facility.

KPDES FORM F

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT APPLICATION

A complete application consists of this form and Form 1.
For additional information, Contact KPDES Branch, (502) 564-3410.

I. OUTFALL LOCATION	AGENCY USE							

For each outfall list the latitude and longitude of its location to the nearest 15 seconds and name the receiving water.

A. Outfall Number	B. Latitude			C. Longitude			D. Receiving Water (name)
017	38	10	08	82	37	15	Big Sandy River
019	38	10	09	82	37	04	Big Sandy River

II. IMPROVEMENTS

A. Are you now required by any federal, state, or local authority to meet any implementaiton schedule for the construction, upgrading or operation of wastewater treatment equipment or practices or any other environmental programs which may affect the discharges described in this application? This includes, but is not limited to, permit conditions, administrative or enforcement orders, enforcement compliance schedule letters, stipulations, court orders, and grant or loan conditions.

1. Identification of Conditions, Agreements, Etc.	2. Affected Outfalls No.	Source of Discharge	3. Brief Description of Project	4. Final Compliance Date a. req.	b. proj.
N/A	N/A	N/A	N/A	N/A	N/A

B. You may attach additional sheets describing any additional water pollution (or other environmental projects which may affect your discharges) you now have under way or which you plan. Indicate whether each program is now under way or planned, and indicate your actual or planned schedules for construction.

III. SITE DRAINAGE MAP

Attach a site map showing topography (or indicating the outline of drainage areas served by the outfall(s) covered in the application if a topographic map is unavailable) depicting the facility including: each of its intake and discharge structures; the drainage area of each storm water outfall; paved areas and buildings within the drainage area of each storm water outfall, each know past or present areas used for outdoor storage or disposal of significant materials, each existing structural control measure to reduce pollutants in storm water runoff, materials loading and access areas, areas where pesticides, herbicides, soil conditioners and fertilizers are applied; each of its hazardous waste treatment, storage of disposal units (including each area not required to have a RCRA permit which is used for accumulating hazardous waste under 40 CFR 262.34); each well where fluids from the facility are injected underground; springs, and other surface water bodies which receive storm water discharges from the facility.

IV. NARRATIVE DESCRIPTION OF POLLUTANT SOURCES

A. For each outfall, provide an estimate of the area (include units) of impervious surfaces (including paved areas and building roofs) drained to the outfall, and an estimate of the total surface area drained by the outfall.

Outfall Number	Area of Impervious Surface (provide units)	Total Area Drained (provide units)	Outfall Number	Area of Impervious Surface (provide units)	Total Area Drained (provide units)
007	7.7 acres	91.8 acres	013	0.0 acres	0.4 acres
008	0.0 acres	5.7 acres	014	0.0 acres	2.0 acres
009	0.0 acres	104.3 acres	015	0.35 acres	1.7 acres
010	0.0 acres	0.8 acres	016	0.1 acres	0.7 acres
011	0.0 acres	1.3 acres	017	5.2 acres	38.8 acres
012	0.0 acres	1.2 acres	019	0.4 acres	1.5 acres

B. Provide a narrative description of significant materials that are currently or in the past three years have been treated, stored or disposed in a manner to allow exposure to storm water; method of treatment, storage, or disposal; past and present materials management practices employed to minimize contact by these materials with storm water runoff; materials loading and access areas; and the location, manner, and frequency in which pesticides, herbicides, soil conditioners, and fertilizers are applied.

A 500,000 gallon diked fuel oil tank and associated piping, trenched fly ash lines, electrical transformers are within the drainage area of Outfall 007. Tote tanks and diked tanks holding sulfuric acid and HEDP are within the drainage areas of Outfalls 008. Tote tanks and diked tanks holding sulfuric acidd and HEDP and G.E. Betz Spectrus CT 1300 and AZ8104 are within the drainage area of 016. Sodium hypochlorite and sodium bromide tanks (inside bldgs. on both units) are also within the drainage area of Outfalls 008 and 016. Also within the drainage area of 008 are storage tanks of ammonia hydroxide and used oil tote tanks. Tote tanks containing G.E. Betz PY5200, Spectrus BD 1501, Spectrus CT 1300, AZ 8104, sodium hydroxide and Nalco 1232 cleaner are stored within Outfall 015. Outfall 017 contains a diked electrical transformer, underground concrete vaults containing brine, a coal conveyor, a vehicle washing facility and herbicides are used on the railroad tracks to control weeds.

C. For each outfall, provide the location and a description of existing structural and nonstructural control measures to reduce pollutants in storm water runoff; and a description of the treatment the storm water receives, including the schedule and type of maintenance for control and treatment measures and the ultimate disposal of any solid or fluid wastes other than by discharge.

Outfall Number	Treatment	List Codes from Table F-1
All	Catch basin gratings prevent large debris and particles from entering the storm drains. Many of the catch basins are surrounded by grassy areas which act as filters or buffer zones to prevent the release of solids. Others are surrounded by gravel which may act in a similar manner. Outfalls are inspected periodically and good housekeeping measures are also practiced.	1-T

V. NONSTORMWATER DISCHARGES

A. I certify under penalty of law that the outfall(s) covered by this application have been tested or evaluated for the presence of non-storm water discharges, and that all non-storm water discharges from these outfall(s) are identified in either an accompanying Form C or Form SC application for the outfall.

Name and Official Title (type or print)	Signature	Date Signed
John M. McManus - Vice President	Patrick N Walsh for John M. McManus	Sept 27, 2005

B. Provide a description of the method used, the date of any testing, and the onsite drainage points that were directly observed during a test.

From the analysis of the water usage flow diagram, all storm water discharges are normally free of non-storm water discharges.

I. SIGNIFICANT LEAKS OR SPILLS

Provide existing information regarding the history of significant leaks or spills of toxic or hazardous pollutants at the facility in the last three years, including the approximate date and location of the spill or leak, and the type and amount of material released.

12-23-02 Underground fuel oil return tank overlow into outfall 015, approx. 1000 gals. (did not reach the river).
6-25-03 No. 6 fuel oil undergound piping leak from a 3" return line. Unknown quantity.
12-17-03 spilled approx. 50 gals. of no. 2 diesel fuel when testing new pumps
1-26-04 spilled approx.2,000 gals. of no. 2 diesel fuel at coal yard that went into the coal pile runoff ponds.

VII. DISCHARGE INFORMATION

A,B,C, & D: See instructions before proceeding. Complete one set of tables for each outfall. Annotate the outfall number in the space provided. Tables F-1, F-2, and F-3 are included on separate pages.

E: Potential discharges not covered by analysis - is any toxic pollutant listed in Table F-2, F-3, or F-4, a substance which you currently use or manufacture as an intermediate or final product or by product.

☐ Yes (list all such pollutants below) ☒ No (go to Section IX)

VIII. BIOLOGICAL TOXICITY TESTING DATA

Do you have any knowledge or reason to believe that any biological test for acute or chronic toxicity has been made on any of your discharges or on a receiving water in relation to your discharge within the last 3 years?

☐ Yes (list all such results below) ☒ No (go to Section IX)

N/A

IX. CONTRACT ANALYSIS INFORMATION

Were any of the analyses reported in item VII performed by a contract laboratory or consulting firm?

☒ Yes (list the name, address and telephone number of, and pollutants analyzed by each such laboratory or firm below; use additional sheets if necessary).

☐ No (go to Section IX)

A. Name	B. Address	C. Area Code & Phone No.	D. Pollutants Analyzed
SGS Environmental Services, Inc.	1258 Greenbrier Steet Charleston, WV 25311	(304) 346-0725	KPDES Form F: color, bromide, surfactants, BOD, fecal coliform
AEP Dolan Environmental Laboratory, Inc.	400 Bixby Road Groveport, OH 43125	(614) 836-4188	aluminum,iron, Mg, Mn, As, Ba, Be, Cr, Co, Cu, Pb, Hg, Mo, Ni, Se, Ag, Tl, Ti, Zn, NH3, B, COD, Cl, F, NO3, NO2, P, TSS, SO4, TKN,TON
Big Sandy Plant Lab	23000 Hwy 23 Louisa, KY 41230	(606) 686-2415 ext. 1316	flow, temp., pH, FAC, TRC, TRO, Tot. Br.,Hardness, DO

X. CERTIFICATION

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information including the possibility of fine and imprisonment for knowing violations.

NAME & OFFICIAL TITLE (type or print)	AREA CODE AND PHONE NO.
John M. McManus - Vice President	(614) 716-1268
SIGNATURE	**DATE SIGNED**
Patrick A [illegible] for John M. McManus	Sept 27 2005

Revised June 1999

VII. DISCHARGE INFORMATION	OUTFALL NO: 007

Part A - You must provide the results of at least one analysis for every pollutant in this table. Complete one table for each outfall. See instructions for additional details.

Pollutant and CAS Number (if available)	Maximum Values (include units)		Average Values (include units)		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During 1st 20 Minutes	Flow-weighted Composite	Grab Sample Taken During 1st 20 Minutes	Flow-weighted Composite		
Oil and Grease	1.0 mg/l	N/A			1	vehicle traffic, coal and ash fines
Biological Oxygen Demand BOD_5	<2.0 mg/l	<2.0 mg/l			1	
Chemical Oxygen Demand (COD)	56 mg/l	38 mg/l			1	
Total Suspended Solids (TSS)	874 mg/l	401 mg/l			1	
Total Kjeldahl Nitrogen	5.16 mg/l	5.23 mg/l			1	
Nitrate plus Nitrite Nitrogen	1.53 mg/l	5.62 mg/l			1	
Total Phosphorus	<0.01 mg/l	1.96 mg/l			1	
pH	Minimum 7.92	Maximum	Minimum	Maximum		

Part B - List each pollutant that is limited in an effluent guideline which the facility is subject to or any pollutant listed in the facility's KPDES permit for its process wastewater (if the facility is operating under an existing KPDES permit). Complete one table for each outfall. See the instructions for additional details and requirements.

Pollutant and CAS Number (if available)	Maximum Values (include units)		Average Values (include units)		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During 1st 20 Minutes	Flow-weighted Composite	Grab Sample Taken During 1st 20 Minutes	Flow-weighted Composite		
color	10 PCU	10 PCU			1	metal structures, coal and ash fines
bromide	<5.0 mg/l	<5.0 mg/l			1	
surfactants	0.033 mg/l	0.044 mg/l			1	
aluminum	13.5 mg/l	9.16 mg/l			1	
iron	16.2 mg/l	9.96 mg/l			1	
magnesium	9.5 mg/l	15.0 mg/l			1	
manganese	0.53 mg/l	0.26 mg/l			1	
arsenic	13 ug/l	7 ug/l			1	
barium	180 ug/l	123 ug/l			1	
beryllium	1.7 ug/l	1.0 ug/l			1	
chromium	22 ug/l	15 ug/l			1	
cobalt	13 ug/l	7 ug/l			1	
copper	56 ug/l	43 ug/l			1	
lead	23 ug/l	13 ug/l			1	
mercury	<0.2 ug/l	<0.2 ug/l			1	
molybdenum	5 ug/l	4 ug/l			1	
nickel	28 ug/l	17 ug/l			1	

selenium	8 ug/l	7 ug/l				

Part C - List each pollutant shown in Tables F-2, F-3, and F-4 that you know or have reason to believe is present. See the instructions for additional details and requirements. Complete one table for each outfall.

Pollutant and CAS Number (if available)	Maximum Values (include units)		Average Values (include units)		Number of Storm Events Sampled	Sources of Pollutants
	Grab Sample Taken During 1st 20 Minutes	Flow-weighted Composite	Grab Sample Taken During 1st 20 Minutes	Flow-weighted Composite		
silver	<0.2 ug/l	<0.2 ug/l			1	metal structures, coal and ash fines
thallium	<1 ug/l	<1.0 ug/l			1	
titanium	284 ug/l	199 ug/l			1	
zinc	466 ug/l	242 ug/l			1	
ammonia, NH3	<0.05 mg/l	<0.05 mg/l			1	
boron	0.05 mg/l	0.06 mg/l			1	
chloride	10 mg/l	17 mg/l			1	
cyanide	<0.01 mg/l				1	
fluoride	0.2 mg/l	0.3 mg/l			1	
FAC	0.02 mg/l				1	
oil & grease	1 mg/l				1	
phenolics	0.001 mg/l				1	
sulfate	58 mg/l	131 mg/l			1	
TON	0.17 mg/l	2.04 mg/l			1	
TRC	0.02 mg/l				1	
TRO	0.04 mg/l				1	
Tot. Bromine	0.05 mg/l				1	
hardness	96 mg/l				1	
DO	6.48 mg/l				1	
fecal coliform	<4000 c/100ml				1	

Part D - Provide data for the storm event(s) which resulted in the maximum values for the flow-weighted composite sample.

1. Date of Storm Event	2. Duration of Storm Event (in minutes)	3. Total rainfall during storm event (in inches)	4. Number of hours between beginning of storm measured and end of previous measurable rain event	5. Maximum flow rate during rain event (gal/min or specify units)	6. Total flow from rain event (gallons or specify units)
8-16-05	110 minutes	1.425 inches	120 hours	5.05 MGD	224,000 gallons

7. Provide a description of the method of flow measurement or estimate.

Measured the inches of water in outfall 007 discharge pipe and used an EPA formula for estimating flow from an open channel pipe.

Fallsburg / Prichard, KY – W Va Quadrangles

USGS Topographic Map

N

Quadrangle Location

\## Outfall Number

Plant Latitude 38° 10' 16"
Plant Longitude 82° 37' 04"

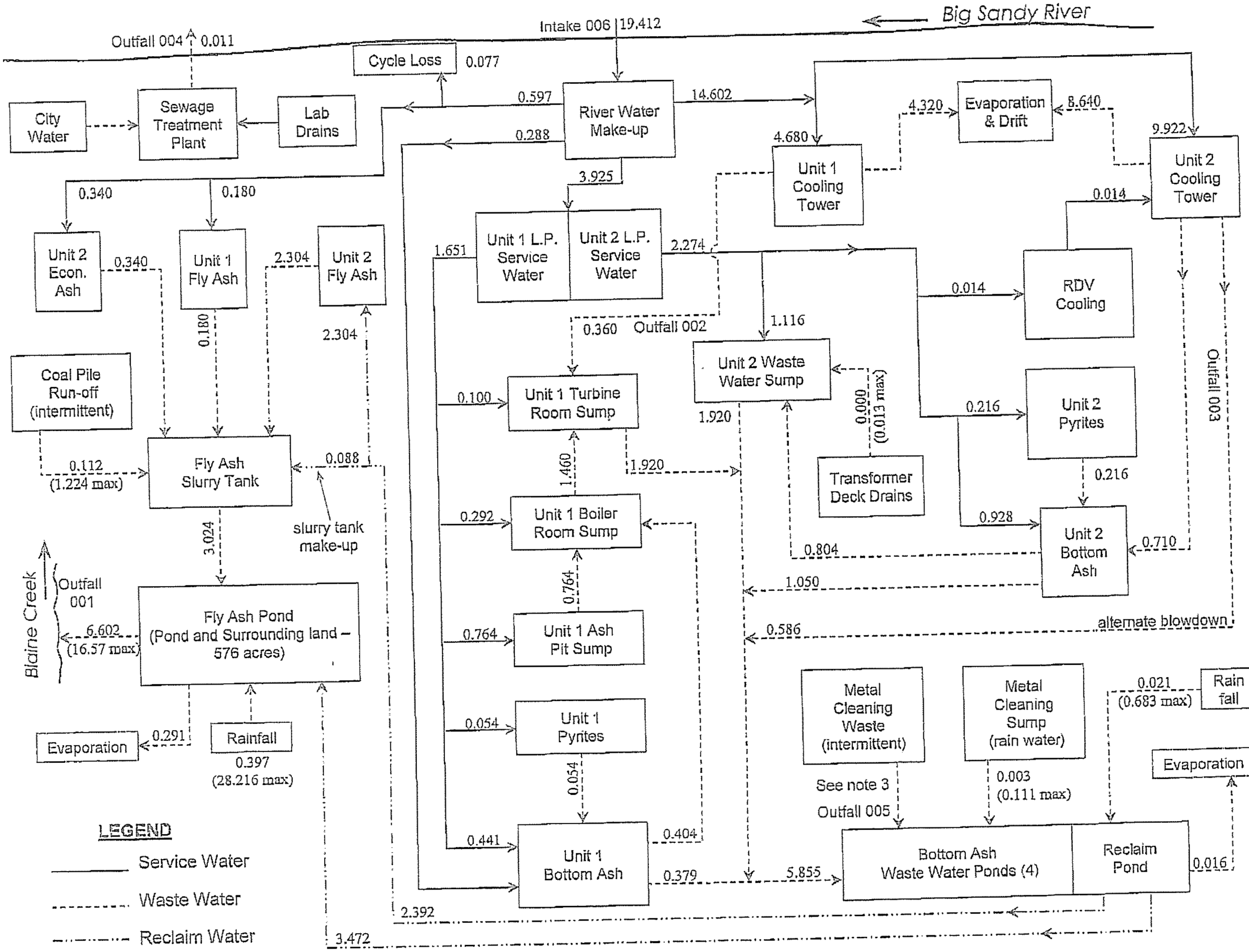
Kentucky Power Company

Big Sandy Plant

USGS Topographic Map

Water & Ecological Resource Services

08.25.05



NOTES:

1. Flows represent actual water usage with both units operating at full load.
2. Normal rainfall values based on avg. annual rainfall of 46.36 in/yr. Maximum rainfall includes rainfall for a 10yr – 24 hr event (4.1 in/day).
3. Approximately 500,000 gallons every 5 to 7 years.

ALL FLOWS MEASURED IN MILLION GALLONS PER DAY (MGD)

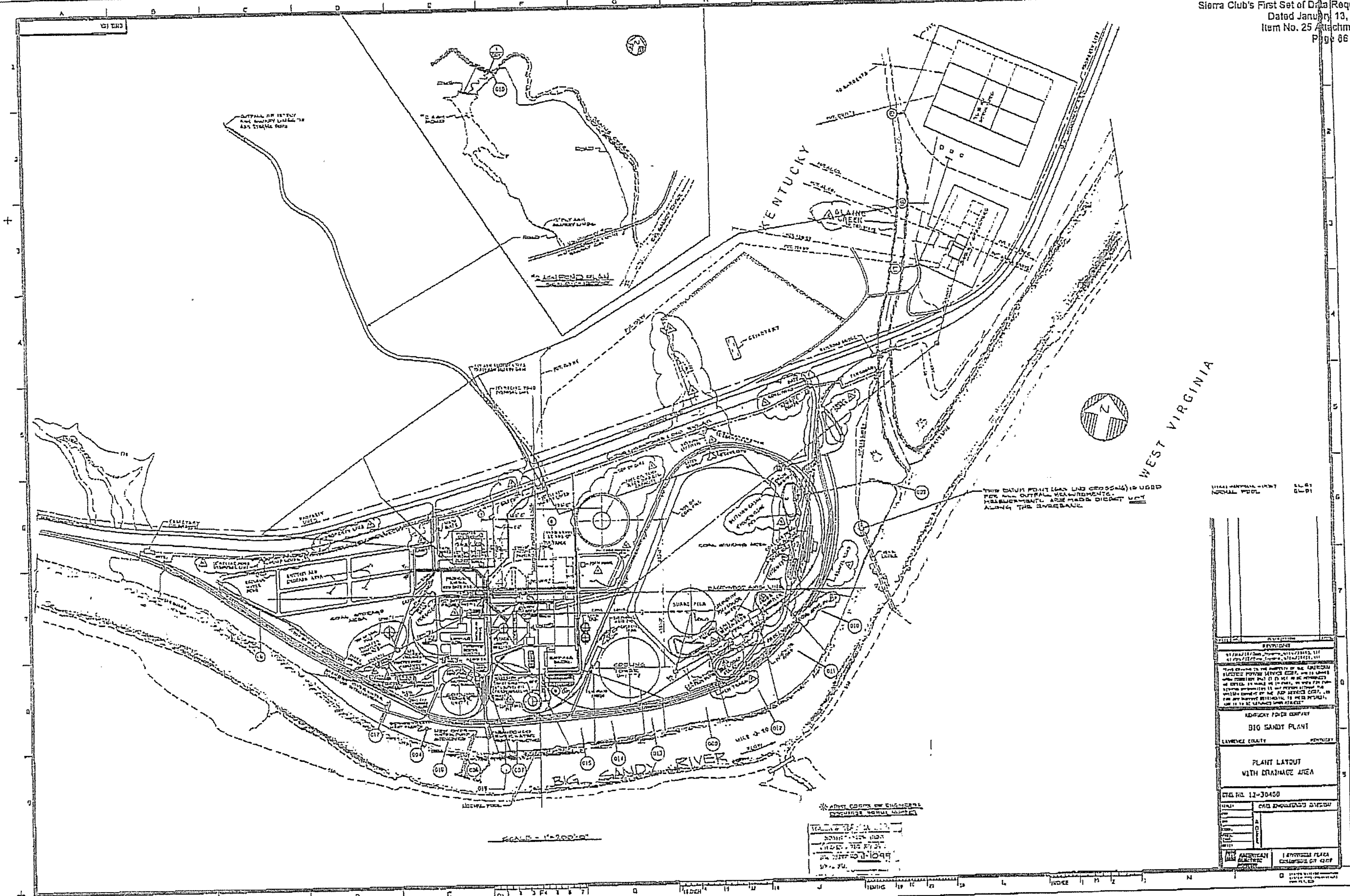
Kentucky Power Company

Big Sandy Plant

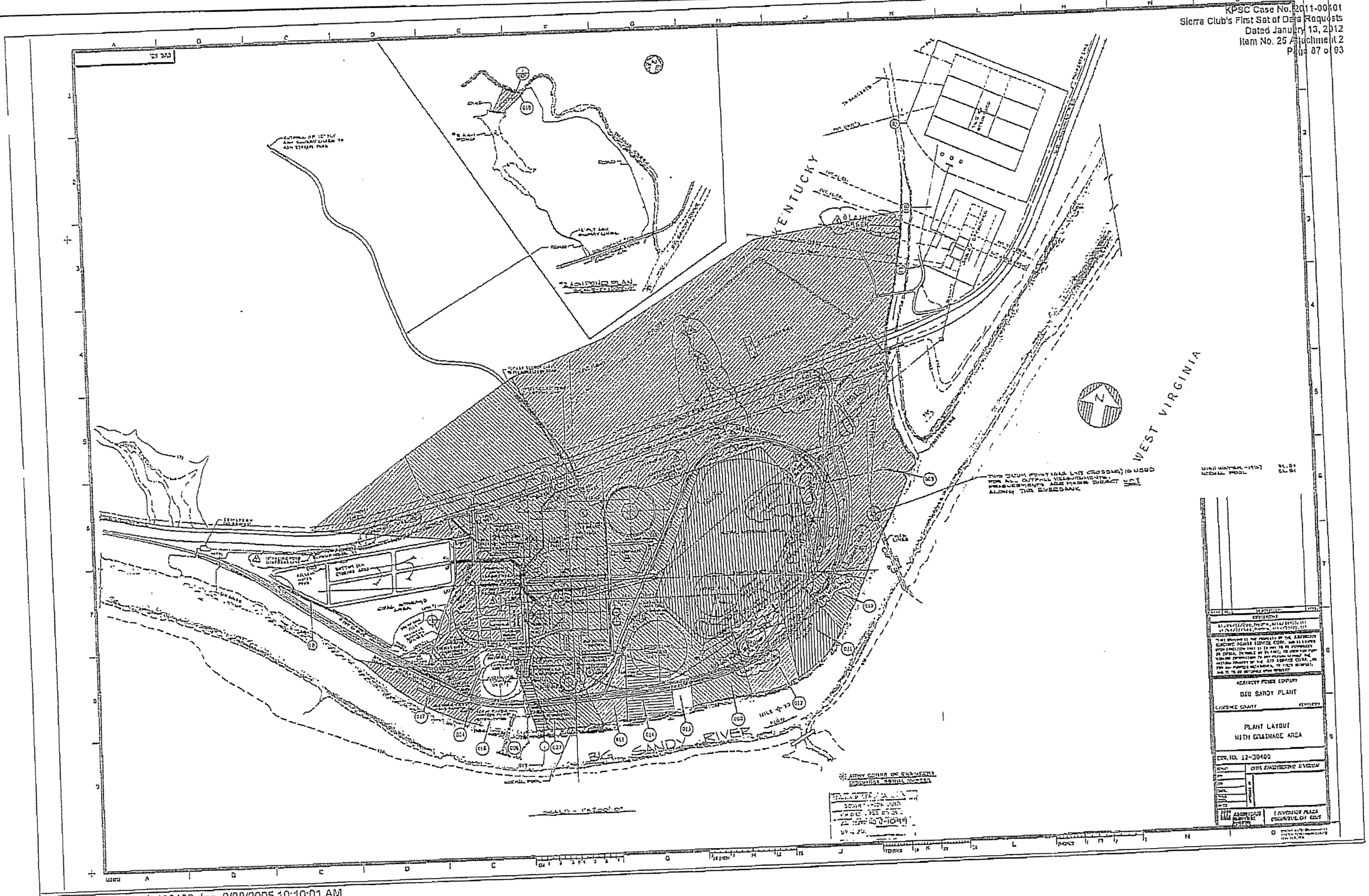
Water Usage Flow Diagram

Water & Ecological Resource Services

10.26.01 BS_waterusage


KENTUCKY
WEST VIRGINIA
BIG SANDY RIVER
COOLING TOWER
COAL HANDLING AREA
KENTUCKY POWER COMPANY
BIG SANDY PLANT
LAWRENCE COUNTY
KENTUCKY
PLANT LAYOUT
WITH DRAINAGE AREA
DWG. NO. 12-30400
AMERICAN ELECTRIC POWER

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 25 Attachment 2
Page 87 of 93



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KENTUCKY POWER COMPANY - BIG SANDY PLANT

DESCRIPTION OF TREATMENT SYSTEMS AND OUTFALLS

Outfall 001 - Fly Ash Pond Discharge

The Big Sandy Plant, like any coal-fired electric generating station its size, produces large quantities of coal ash, as well as other process wastes. In developing a method for treatment and disposal of plant wastes which, in terms of volume, consist almost entirely of ash, an efficient wastewater treatment scheme was designed enabling the plant to have only one process wastewater discharge, the fly ash pond discharge to Blaine Creek (Outfall 001).

At Big Sandy Plant, various waste streams have been combined for treatment and reuse. Specifically, the cooling tower blowdown from Unit 2 is used to sluice Unit 2 bottom ash and pyrites to the bottom ash wastewater treatment system through Outfall 001. Coal pile runoff is discharged to the bottom ash pond. Bottom ash and low-volume wastewaters from both units are also discharged to the bottom ash wastewater system for mixing, self-neutralization, and settling. From the bottom ash wastewater treatment ponds, the treated wastewater is decanted into a reclaim pond. A portion of this water is pumped back to the plant for reuse in sluicing fly ash to the fly ash pond. Excess treated water from the reclaim pond is also pumped directly to the fly ash pond for final clarification with the fly ash transport water, and the combined waste stream is discharged into Blaine Creek.

Periodically, the bottom ash wastewater treatment system receives other wastewater, resulting from the chemical cleaning of the waterside of the steam generating tubes of Unit 2 (Outfall 005) and deslagging operations from both units. The chemical cleaning wastes from Unit 2 are chemically treated in the metal cleaning waste tank to reduce the level of iron and copper below 1 mg/L before discharging into the bottom ash pond. Boiler deslagging wastes and air preheater wash wastes (which do not involve chemicals) are discharged to the bottom ash ponds for self-neutralization and settling via the bottom ash handling system.

The bottom ash wastewater treatment system consists of two series of treatment ponds (two ponds per series) and a reclaim pond. One series of ponds is used while the other is being excavated. Coal ash and other residues from the bottom ash wastewater ponds are temporarily stored for later beneficial reuse. Bottom ash is used by the State Highway Department for ice control on roadways, for plant construction projects, and some is sold as a light-weight aggregate for concrete block construction.

The fly ash pond at Big Sandy Plant was formed by building a dam and utilizing a portion of the hollow drained by Horseford Creek. Therefore, in addition to the wastewater input to the fly ash pond, the pond receives rainfall runoff from the Horseford Creek drainage basin of 576 acres, of which 135 acres are occupied by the fly ash pond. In 1993, a permit to raise the dam was received from the Kentucky Department of Environmental Protection utilizing a segmented construction methodology. This on-going construction project will increase the area of the fly ash pond to approximately 185 acres.

Outfalls 002 and 003 - Cooling Tower Blowdowns

Big Sandy Units 1 and 2 utilize natural draft hyperbolic cooling towers in conjunction with closed cycle cooling water (CCCW) systems to condense steam into condensate. The Unit 1 CCCW system circulates water at a rate of 120,000 GPM while the Unit 2 CCCW system circulates water at a rate of 250,000 GPM. Water is drawn from the cooling tower basins by pumps, circulated through the main steam turbine condensers, and returned to the cooling towers. The closed cycle is completed as the water returns to the circulating water pumps via open concrete flumes. The individual circulating water systems are treated with sodium hypochlorite and sodium bromide for one to two 30-minute periods per day. The circulating water systems are also treated with sulfuric acid for pH control, PY 5200,a deposit control agent (a dispersent) and 1-hydroxyethylidine-1,1-diphosphonic (HEDP) acid to prevent scale formation in the condensers. A copper corrosion inhibitor, AZ8104, and an algaecide, Spectrus CT'300, are also used.

In order to maintain the quality of cooling water required for efficient operation of the circulating water systems, it is necessary to blowdown (discharge) a portion of the circulating water. Blowdown is accomplished on Unit 1 by opening a manually-operated valve which discharges through Outfall 002 to the Unit 1 turbine room sump. The water from the turbine room sump is subsequently pumped to the bottom ash pond (see enclosed water usage flow diagram). The circulating water system on Unit 2 is blown down by using cooling tower water, discharging through Outfall 003, to transport bottom ash from Unit 2 to the bottom ash storage ponds (see enclosed water usage flow diagram). An alternate blowdown for the Unit 2 cooling tower also discharges into the bottom ash pond. Each cooling tower basin is equipped with an emergency overflow to the Big Sandy River. In the event of an emergency, the Unit 1 cooling tower overflow would discharge through Outfall 007, and the Unit 2 overflow would discharge through Outfall 008.

Outfall 004 - Sewage Treatment Plant

The sewage treatment plant is a prefabricated package sewage treatment plant, which utilizes a modified activated sludge treatment process known as "extended aeration." The treatment facility has a design capacity of 15,000 GPD and consists of the following:

- A 1" spaced inlet bar screen
- A 6,600 gallon equalization chamber
- A 15,000 gallon aeration chamber
- A 2,500 gallon clarifying chamber
- A 3,000 gallon sludge holding chamber
- A 2,100 gallon chlorination chamber
- A dechlorination unit

Wastewater passing through the sewage treatment plant is processed by the following treatment stages:

- Pretreatment (trash trap and inlet bar screen)
- Equalization
- Aeration
- Clarification
- Chlorination
- Dechlorination

Sanitary wastewater passes through a bar screen and enters the equalization chamber which is equipped with grinder pumps to facilitate transfer of solid waste to the aeration chamber. The flow rate to the aeration chamber is controlled by a flow-splitter channel equipped with manually-operated slide gates to allow water to be directed to the aeration chamber or returned to the equalization chamber. The aeration chamber is designed to give a 24-hour retention time. The incoming sewage is mixed with an activated sludge containing bacteria and other microorganisms to decompose the sewage. Wastewater flows from the aeration chamber into the clarifier where floating solids are skimmed and the activated sludge settles to the bottom. The floating solids and settled sludge are recirculated back to the aeration chamber.

Clarified wastewater passes through a chlorine contact chamber for a minimum of thirty (30) minutes. Chlorine for disinfection is provided by a tablet chlorination system which allows HTH tablets to dissolve releasing the chlorine at a rate to provide approximately 1 ppm residual. The chlorinated wastewater then passes through a dechlorination chamber prior to discharge to Big Sandy River. Sodium bicarbonate is used for pH control and table sugar is occasionally used for microbial metabolic substrate.

Outfall 005 - Metal Cleaning Waste Tank

Outfall 005 is only used to decant supernatant from the chemical metal cleaning waste (CMCW) tank. The waste is generated by chemically cleaning the water side of the boiler tubes in Unit 2 and is collected in the CMCW tank. Chemical cleaning wastewater from Unit 2 can be treated in the tank to precipitate iron and copper and allow the supernatant to be discharged to the bottom ash pond when levels of iron and copper in the supernatant are below 1 mg/l. Alternate cleaning solutions may be stored in the tank for future incineration in the boiler or for shipment to an off-site disposal facility. The bottom ash pond overflows into the reclaim pond. Discharge through this outfall is intermittent as the Unit 2 boiler is typically cleaned every 5 to 7 years. Wastes generated from a Unit 1 cleaning are collected in frac tanks and incinerated in Unit 1 when it returns to full operational load.

Reverse Osmosis System

The plant has a reverse osmosis system for the production of demineralized water for boiler make-up feed water. Sodium hydroxide and sodium bisulfite are used routinely for maintenance of the system. The following chemicals have been approved for use as cleaning agents for the reverse osmosis membranes: Nalco PC 191, Nalco PC-56, Nalco PC 11, Nalco PC-77, and Nalco PC-99.

In addition, brine is used for water softening and CDP 450 is used as a coagulant for the treatment of river water. These may be discharged to the Unit 2 wastewater sump.

Outfall 006 - Plant Intake

Outfall 006 is the designation given to the intake structure used to withdraw water from the Big Sandy River. The only water discharged at this designated outfall is from the pump house floor drains and the pump house sump, which collects pump seal water. The source of these waters is the Big Sandy River and no treatment is provided before discharging back into the river.

Outfall 007 - Storm Drain

Outfall 007 receives stormwater runoff from 91.8 acres north of U.S. 23 (including highway drainage), the area north of Unit 2, and the area around the performance building and behind the storage warehouses. Also, occasional fire header flushing and Unit 1 cooling tower emergency overflow may be discharged through this storm drain. Unit 1 condensate storage tank overflow and drain discharge through outfall 007. During a Unit 2 outage this drain will collect water from the cooling water coolers and auxiliary blowdown. This outfall discharges to the Big Sandy River at River Mile (RM) 20.4.

Outfall 008 - Storm Drain

Outfall 008 receives stormwater runoff from 5.7 acres located west of the Unit 2 coal storage area and Unit 2 turbine roof drains. Also, Unit 2 condensate storage tank overflow, Unit 2 wastewater sump overflow, south Unit 2 coal pile drainage pond sump overflow, occasional fire header flushing, and Unit 2 cooling tower emergency overflow may be discharged through this storm drain. This outfall discharges to the Big Sandy River at RM 20.1.

Outfall 009 - Storm Drain

Outfall 009 receives stormwater runoff from 104.3 acres located north of U.S. 23 and north of the Unit 2 coal storage area. This outfall discharges to the Big Sandy River at RM 19.6.

Outfall 010 - Storm Drain

Outfall 010 receives storm water runoff from 0.8 acres located east of the Unit 2 coal yard buildings. This outfall discharges to the Big Sandy River at RM 19.8.

Outfall 011 - Storm Drain

Outfall 011 receives storm water runoff from the coal yard building roof drains and 1.3 acres located south of the Unit 2 coal yard buildings. This outfall discharges to the Big Sandy River at RM 19.9.

Outfall 012 - Storm Drain

Outfall 012 previously collected drainage from the coal handling area. With the addition of coal truck unloading Station 10 this drainage was rerouted to the coal pile runoff ponds. A small amount of surface and/or groundwater infiltration may still discharge through this outfall to the Big Sandy River.

Outfall 013 - Storm Drain

Outfall 013 receives storm water runoff from 0.4 acres located south of the Unit 2 cooling tower. This outfall discharges to the Big Sandy River at RM 20.2.

Outfall 014 - Storm Drain

Outfall 014 receives storm water runoff from 2.0 acres located west of the Unit 2 cooling tower. This outfall discharges to the Big Sandy River at RM 20.25.

Outfall 015 - Storm Drain

Outfall 015 receives stormwater runoff from 1.7 acres located around the storeroom warehouses, storeroom parking lot, and roof drains. This outfall discharges to the Big Sandy River at RM 20.3.

Outfall 016 - Storm Drain

Outfall 016 receives stormwater runoff from 0.7 acres located around the Unit 1 condensate storage tank and adjoining road. Also, Unit 1 condensate storage tank overflow, Unit 1 cooling tower basin drain, and tower flume overflow may be discharged through this storm drain. This outfall discharges to the Big Sandy River at RM 20.45.

Outfall 017 - Storm Drain

Outfall 017 receives storm water runoff from 38.8 acres located north of U.S. 23, around the bottom ash ponds and parking lot, around the Unit 1 Service Building, coal storage area, tractor sheds, and roof drains. This outfall discharges to the Big Sandy River at RM 20.55. Salt brine used in regenerating the Unit 1 water softener is stored in concrete vaults within the drainage area of Outfall 017. Under normal operation water is added to salt brine and the solution is pumped to the Unit 1 water softener. If equipment failure occurs and water continues to be added beyond the required amount the concrete vault may overflow and pass through Outfall 017.

Outfall 018 - Fly Ash Dam Interior Drains

Outfall 018 is the discharge for interior drains of the fly ash dam. This outfall discharges into Blaine Creek immediately downstream of Outfall 001. Nearby mine seepage is collected in a sump and pumped to the fly ash pond under normal operation. If the sump pumps fail the sump will overflow to this outfall.

Outfall 019 - Storm Drain

This outfall receives stormwater runoff from 1.5 acres located east of the Unit 1 cooling tower. This outfall discharges to the Big Sandy River at RM 20.4.

KENTUCKY POWER COMPANY – BIG SANDY PLANT
APPLICATION NOTES

NOTE 1:

Values recorded in Part VII A, B and C for Outfall 007 are representative of discharges from all storm water outfalls. This is consistent with past NPDES permit renewal applications for this facility and the current NPDES permit.

NOTE 2:

Section 311 (a)(2) of the Clean Water Act provides three exclusions from hazardous substance discharge reporting. These three exclusions were adopted verbatim by Congress in defining federally permitted releases in section 101 (10) of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), 42 U.S.C. 9601(10), which are also exempt from CERCLA hazardous substance release reporting.

Clean Water Act Section 311 reporting Exclusion 2 covers "discharges resulting from circumstances identified and reviewed and made a part of the public record with respect to a permit and made a part of the public record with respect to a permit issued or modified under section 402 of this Act, and subject to a condition in such permit". As noted in the preamble to EPA's August 29, 1979 rule incorporating this provision, Exclusion 2 "applies where the source, nature and amount of a potential discharge was identified and made part of the public record, and a treatment system was made a permit requirement." (44 Fed. Reg. 50766)

Kentucky Power Company hereby requests reporting Exclusion 2 for the following hazardous substances present at the Big Sandy Plant in excess of EPA's reportable quantity:

Ammonium Hydroxide
Sodium Hypochlorite
Ethylene Diaminetetracetic Acid (EDTA)
Sodium Hydroxide
Sulfuric Acid
Sodium Nitrite

Big Sandy Plant has small supplies of Section 311 substances that are used in the laboratory and stored within cabinets of the laboratory. These substances are not expected to ever reach a discharge.

Clean Water Act Section 311 reporting Exclusion 3 covers "continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under Section 402 of the Act, which are caused by events occurring within the scope of relevant operating or treatment systems". 33 U.S.C. 1321(a)(2)(C). Ethylene glycol is a component of Big Sandy Plant's fire protection system. Periodic releases during inspections, training, and emergencies occur to ash ponds.

Kentucky Power Company requests reporting Exclusion 3 coverage for these discharges.

Kentucky Power Company

REQUEST

Direct Testimony of Walton page 22 at 4-12.

a. Please provide the "preliminary Phase I feasibility analysis" from Q3 2004

b. Please provide the reason that "Phase I activities ceased in second quarter 2006" and produce any Company memoranda or documents explaining the outcome of the feasibility analysis

c. Please provide the "refined assessment" indicated on p12, including any bids, estimates, or engineering estimates that substantiate the assertion in lines 11-12 that the "costs to retrofit Big Sandy Unit 2 had increased substantially."

RESPONSE

a. Please see enclosed CD.

b. Please see Walton testimony page 22, lines 2 to 23 through page 23 line 1 for a discussion on the reasons Phase I activities ceased in second quarter 2006. Generally, costs for a WFGD had increased substantially, primarily due to escalation in the cost of labor and materials.

c. Please see the enclosed CD.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Direct Testimony of Walton page 19, lines 9-12

a. For all environmental and non-environmental capital expenditures in the AEP system exceeding $50 million in the last seven years, please provide the initial engineering and design cost estimate, the Company's "Phase IIb" estimate, the final selected bid price, the cost presented for recovery to Commissions in CPCN, predeterminations or rate cases, and the actual incurred cost to AEP.

RESPONSE

Please see Attachment 1 to this response.

WITNESS Ranie K Wohnhas

2004-2011 Major Generation Projects
(total project cost >$50M)

Project	Phase I	Phase I [4]	Phase Iib	Actual	Recovery
	($MM's)	($MM's)	($MM's)	($MM's)	
AM U1 FGD / Assoc / Landfill	255	306	250	308	308
AM U2 FGD / Assoc / Landfill	255	306	250	308	308
AM U3 FGD / Assoc / Landfill	462	554	569	739	739
CD U1 FGD / Assoc / Landfill	309	371	329	308	308
CV U4 FGD / SCR / Assoc / Landfill [3]	531	637	536	506	506
ML U1 FGD / SCR / Assoc	401	481	444	534	534
ML U2 FGD / SCR / Assoc	401	481	438	515	515
MT FGD / Assoc / Landfill	394	473	539	576	576
CD U2 FGD / Assoc	307	307	307	257	n/a
CD U3 FGD / Assoc [2]	510	510	510	480	n/a
CV U5 FGD upgrade	57	68	n/a	64	64
CV U6 FGD upgrade	73	88	n/a	56	56
MT Gypsum Handling	30	36	n/a	55	55
TC U4 PRB Fuel Blend	n/a	n/a	91	84	84
Stall Plant	328	394	n/a	428	428
Mattison Plant	113	136	n/a	127	127
Riverside Plant	62	74	n/a	62	62
Southwestern Plant	62	74	n/a	59	59

Notes:
(1). Dollars amounts are total dollars including overheads and AFUDC.
(2). Actual cost is estimate, projects not yet in service
(3). CV U4-6 Landfill project is still in progress, Actuals represent only spent to date through Dec 2011.
(4). These Phase I estimates contain a 20% contingency allocation for comparative purposes to the Big Sandy Unit 2 Estin

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 11 and 12, Table 1

a. Please list the hours of peak demand in which Big Sandy Unit 1 has been dispatched in the most recent five calendar years for which statistics are available, the MW dispatched and the MWH generated in each of those hours.

b. Please list the hours of peak demand in which Big Sandy Unit 2 has been dispatched in the most recent five calendar years for which statistics are available, the MW dispatched and the MWH generated in each of those hours.

c. Please provide all analyses underlying the Company's decisions in option 2 and option 3 to assume a natural gas combined cycle (CC) plant with duct-firing for peaking purposes, rather than a CC to serve base and intermediate load and a combustion turbine unit to serve peak load.

d. Please provide the heat rate(s) the Company assumed for the natural gas CC plants with duct-firing in option 2 and option 3 respectively, and the rationale supporting those assumptions.

e. Please list each natural gas CC unit that AEP currently owns or operates, and indicate which of those units has duct-firing.

RESPONSE

a. & b. This question has been interpreted as being the Big Sandy unit hourly generation that is coincident with the highest AEP-East peak demand.

	Big Sandy 1 MWh Dispatch Basepoint	Big Sandy 1 MWh Generation	Big Sandy 2 MWh Dispatch Basepoint	Big Sandy 2 MWh Generation
8/8/2007 15:00	260	260	745	789
6/9/2008 15:00	203	215	0	0
8/10/2009 15:00	269	239	714	729
7/23/2010 15:00	263	274	721	800
7/21/2011 17:00	278	277	782	794

Therefore these peak hours offer the attendant coincident generation for Big Sandy Units 1 and 2 during such AEP East System summer peaks, for the most recent 5 calendar years.

c. No analyses were undertaken to compare duct firing for peaking purposes, rather than a CC to serve base and intermediate load and a combustion turbine unit to serve peak load. However, the duct firing capability of the CC provides a lower cost option for peaking capacity than the installation of a separate CT to serve that peaking need and a CC to serve the intermediate load requirement.

d. The modeled heat rate assumptions, by unit:

[redacted]

[redacted]

The heat rates provided were based on analyses completed by Sargent & Lundy (S&L). The stated heat rates represent the cycle performance for the ambient conditions per S&L Report and ASHRAE data as the 1% Summer Wet Bulb condition.

e. AEP currently owns and operates the following three CC plants in its Eastern service territory which all have duct-firing:

1. Dresden
2. Lawrenceburg
3. Waterford

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.

a. Please provide the Company's projection of peak demand and internal load from 2031 through 2040, and the basis for that projection.

b. Please describe the factors driving the Company's projection that the KPC compound rate of growth from 2021 to 2030 will be higher than from 2011 to 2020.

c. Please provide KPC's weather-normalized peak demand and internal load by year for 2001 through 2010, and the corresponding compound annual rate of growth for each.

d. Please provide KPC's actual, weather-normalized internal load by major retail rate class for 2001 through 2010,

e. Please provide KPC's projection of internal load by major retail rate class by year through 2030.

f. Does the AEP Economic Forecasting projection algorithm have a price elasticity component by major retail rate class? If not, why not.

g. Does the forecast in Table 1-1 reflect the price elasticity impact by rate class of the increase in rates that will result from alternative option 1? If so, please explain the feedback process used in the analysis to accomplish that.

h. Please provide a forecast of aggregate peak demand and annual energy that reflects the price elasticity impacts by rate class of the environmental surcharge by year under the Company's proposed 15 year depreciation. Please provide all supporting assumptions and workbooks, in electronic format with operational calculations.

RESPONSE

a. See attached file tab labeled 42(a).

b. Slightly slower growth in the first ten years of the Company's load forecast as compared with the second ten years can be attributed largely to efficiency gains caused by national appliance and lighting standards. These impacts are expected to impact most in the residential and commercial classes. This pattern is consistent with projections developed by the Energy Information Administration. Also see attached file tab labeled 42(b).

c. See attached file tab labeled 42(c).

d. See attached file tab labeled 42(d).

e. See attached file tab labeled 42(e)

f. Yes.

g. The load forecast input price assumptions are based on price trends and not tied to specific projects.

h. See response to 42(g).

WITNESS: Scott C Weaver

Case No. 2011-00401

Sierra Club 42

42. Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.

a. Please provide the Company's projection of peak demand and internal load from 2031 through 2040, and the basis for that projection.

	Summer Peak Demand (MW)*		Internal Load (GWh) **	
	KPCo	AEP-East	KPCo	AEP-East
2011	1,221	20,698	7,666	125,558
2012	1,238	21,101	7,729	127,337
2013	1,239	21,379	7,728	128,585
2014	1,243	21,542	7,755	129,353
2015	1,247	21,672	7,776	129,953
2016	1,252	21,740	7,812	130,522
2017	1,256	21,881	7,848	131,135
2018	1,271	22,033	7,890	131,898
2019	1,281	22,191	7,934	132,740
2020	1,287	22,301	7,976	133,523
2021	1,299	22,529	8,021	134,415
2022	1,309	22,701	8,071	135,300
2023	1,313	22,843	8,122	136,191
2024	1,320	22,972	8,177	137,166
2025	1,333	23,215	8,225	138,101
2026	1,344	23,404	8,276	139,067
2027	1,354	23,599	8,328	140,069
2028	1,362	23,751	8,382	141,118
2029	1,369	23,962	8,429	142,089
2030	1,379	24,165	8,479	143,121
2031	1,389	24,375	8,530	144,193
2032	1,396	24,532	8,584	145,324
2033	1,409	24,800	8,631	146,372
2034	1,414	24,974	8,681	147,421
2035	1,424	25,186	8,732	148,493
2036	1,429	25,337	8,784	149,644
2037	1,445	25,638	8,835	150,815
2038	1,455	25,861	8,886	151,977
2039	1,466	26,089	8,938	153,150
2040	1,467	26,214	8,989	154,294

Compound Growth Rates:				
2011-2020	0.59%	0.83%	0.44%	0.69%
2011-2030	0.64%	0.82%	0.53%	0.69%
2011-2040	0.63%	0.82%	0.55%	0.71%

*Summer Peak Demand in MW diversified to PJM annual peak.

Case No. 2011-00401

Sierra Club 42

42. Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.

b. Please describe the factors driving the Company's projection that the KPC compound rate of growth from 2021 to 2030 will be higher than from 2011 to 2020

Response: Slightly slower growth in the first ten years of the Company's load forecast as compared with the second ten years can be attributed largely to efficiency gains caused by national appliance and lighting standards. These impacts are expected to impact most in the residential and commercial classes. This pattern is consistent with projections developed by the Energy Information Administration.

	Peak Demand		Energy *	
	MW	Compound Growth Rates	GWh	Compound Growth Rates
2011	1,221		7,666	
2012	1,238		7,729	
2013	1,239		7,728	
2014	1,243		7,755	
2015	1,247		7,776	
2016	1,252		7,812	
2017	1,256		7,848	
2018	1,271		7,890	
2019	1,281		7,934	
2020	1,287	0.59%	7,976	0.44%
2021	1,299		8,021	
2022	1,309		8,071	
2023	1,313		8,122	
2024	1,320		8,177	
2025	1,333		8,225	
2026	1,344		8,276	
2027	1,354		8,328	
2028	1,362		8,382	
2029	1,369		8,429	
2030	1,379	0.66%	8,479	0.62%

* Annual GWh differences result from a revised Cumulative Energy Efficiency estimate

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42. Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.
c. Please provide KPC's weather-normalized peak demand and internal load by year for 2001 through 2010, and the corresponding compound annual rate of growth for each.

	Summer Non-Coincident Peak Demand (MW)*		Internal Load (GWh)*	
	KPCo	AEP-East	KPCo	AEP-East
2001	1,260	19,994	7,463	113,484
2002	1,300	20,253	7,742	115,135
2003	1,248	20,113	7,549	115,813
2004	1,280	20,216	7,844	117,890
2005	1,287	20,559	7,976	119,754
2006	1,267	21,046	7,854	123,807
2007	1,269	21,687	7,710	128,824
2008	1,265	21,606	7,877	131,414
2009	1,245	20,383	7,608	121,964
2010	1,273	20,961	7,740	123,320
2001-2010 Compound Growth Rate	0.11%	0.53%	0.41%	0.93%

*Weather adjusted

Case No. 2011-00401

Sierra Club 42

42. Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.

d. Please provide KPC's actual, weather-normalized internal load by major retail rate class for 2001 through 2010,

	Weather normalized GWh load*						
	Residential	Commercial	Industrial	Other Retail	Wholesale	Losses	Total
2001	2,346	1,282	3,126	11	79	618	7,463
2002	2,454	1,316	3,154	11	93	713	7,742
2003	2,391	1,324	2,930	11	90	804	7,549
2004	2,447	1,381	3,181	11	96	729	7,844
2005	2,494	1,404	3,343	10	96	628	7,976
2006	2,509	1,418	3,311	10	98	508	7,854
2007	2,434	1,424	3,174	10	99	569	7,710
2008	2,460	1,429	3,322	10	100	555	7,877
2009	2,453	1,438	3,206	10	94	406	7,608
2010	2,501	1,439	3,256	10	100	435	7,740

2001-2010 Compound Growth Rate

0.71%	1.29%	0.45%	-1.01%	2.56%	-3.84%	0.41%

*Retail and wholesale classes are summed premise metered loads (i.e., excludes losses).

Case No. 2011-00401

Sierra Club 42

42. Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.

e. Please provide KPC's projection of internal load by major retail rate class by year through 2030.

GWh Load* **

	Residential	Commercial	Industrial	Other Retail	Wholesale	Internal Load	DSM	Internal Load Before DSM
2011	2,643	1,543	3,356	11	101	7,654	12	7,666
2012	2,662	1,545	3,378	11	103	7,699	30	7,729
2013	2,620	1,544	3,400	11	103	7,679	49	7,728
2014	2,596	1,546	3,435	11	104	7,692	63	7,755
2015	2,577	1,547	3,463	11	104	7,702	74	7,776
2016	2,558	1,541	3,496	11	104	7,711	101	7,812
2017	2,542	1,541	3,529	11	105	7,729	119	7,848
2018	2,535	1,546	3,563	11	105	7,761	129	7,890
2019	2,532	1,552	3,595	11	106	7,796	137	7,934
2020	2,526	1,558	3,629	11	106	7,831	144	7,976
2021	2,526	1,568	3,664	11	106	7,876	146	8,021
2022	2,529	1,578	3,699	12	107	7,924	146	8,071
2023	2,534	1,589	3,733	12	107	7,975	146	8,122
2024	2,543	1,601	3,767	12	108	8,031	146	8,177
2025	2,549	1,613	3,799	12	108	8,081	145	8,225
2026	2,557	1,625	3,830	12	108	8,132	144	8,276
2027	2,567	1,636	3,862	12	108	8,184	144	8,328
2028	2,579	1,646	3,893	12	109	8,237	144	8,382
2029	2,587	1,655	3,922	12	109	8,284	144	8,429
2030	2,597	1,665	3,951	12	109	8,334	144	8,479
Compound Growth Rates:								
2011-2020	-0.50%	0.11%	0.88%	0.11%	0.56%	0.25%	31.67%	0.44%
2011-2030	-0.09%	0.40%	0.86%	0.14%	0.42%	0.45%	13.93%	0.53%

*Includes losses.

** Annual GWh differences result from a revised Cumulative Energy Efficiency estimate

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 21.

a. For Option 1, please provide the assumptions used as inputs to Strategist for the major non-environmental related capital costs KPC expects to incur in order to keep Big Sandy Unit 2 running through 2040, e.g. boiler rebuilds, superheaters, reheaters, or waterwall tubes, etc.

b. If KPC did not assume any future non-environmental capital costs for Option 1 please explain why not.

c. Please provide all major non-environmental related capital costs KPC incurred by year from 2002 through 2011.

RESPONSE

a. Please see Attachment 1, page 1 of 2, for costs through 2020. Capital costs beyond 2020 were escalated using a 5-year rolling average.

b. N/A

c. See Attachement 1, page 2 of 2 for data back to 2004. The current reporting system does not have data in this format prior to 2004.

WITNESS: Scott C Weaver

Big Sandy Unit 2 Major Non-Environmental Related Capital Costs

Sum of Fore $(000's)	Years #										
Project	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Grand Total
Economizer Casing Support Stru					8000						8000
BS2 Replace C W Piping								2192			2192
BS2 Repl rear wall ash hopper								5000			5000
Replace U2 BFPT with spare					234						234
Repl nose U2 main furnace								6600			6600
BS-Repl Sta 14 switchgear					1150						1150
Turbine Rotor LP A/B U2			1000								1000
BS2 HP R/H & 2nd R/H	1356										1356
Replace seal skirt U2					325						325
LPA & B Rotor LSB - Replace				3975							3975
Second RH Rotor Repairs		535									535
Lower L&R Sidewall Hdrs & Tubi								2000			2000
Aux Condenser Retube U2								1200			1200
BS1 Replace Manlifts Sta 11,12	2692										2692
Upgrade EHC Pumps & Piping U2	300										300
Rewedge Generator U2	340										340
Boiler & Auxiliaries PPB<100k		27	27	20		201	111				386
Boiler MU Water Supply PPB<100	29	191	26	26	26	226	162				686
Coal Pulv Mills PPB<100k						68	68	68			204
Condenser & Aux. PPB<100k								290			290
Other Costs PPB<$100k		117				88		103			308
Other Environ Repl <100k	9	9	9	9	8	9	9	9			71
PPB Env Repl Outage <100k	131	50	50	50	60	260	80	80			761
Capital PPB U2 Outage									110		110
U 2 PPB Outage <100k			90	92	165	214	184	467			1232
Sec Air Exp Jt PPB Out >100k			150			220					370
Repl 6 precip outlet hoppers								195			195
Rebuild #21pulv grinding zone	190	190	180	180	175	190		190			1295
Replace #23 pulv gearbox						125		125			250
Repl bull gear in #2 air compr	179	101	167	103	178	179		179			1086
Inst pulv motors with TEFC	60	60	93	60							273
Upgrade protective relaying	50					84					134
Heat Rate Instrumentation U2						78	78	80			236
MCC & VCC Replacement U2								90			90
Air Htr Exp. Joints-Outlet U2	120	116	120	120		120	120	120			836
Repl 2 U2 blr expansion joints						300					300
Repl U2 boiler refractory					75			200			275
Repl burner exp joints U2						100		100			200
Repl U2 PA fan rotor	175										175
Repl turb crossover exp jts			170								170
HP Turb (ADSP) Rep for stock		250									250
Boiler Room Roof U2						250					250
Turbine Heater Bay Roof U2							180				180
Cooling Water Coolers Upgrade						260					260
Ovation Control Sys Upgrades						119					119
Water Chemistry Sample Room U2						225					225
Replace Plant Batteries U2	165										165
Retube Hydrogen Coolers U2								0			0
Redundant Steam Packing Exhaus								115			115
Air htr baskets & sector plate			6600								6600
BS2 Repl penthse casing & seal										2500	2,500
GWSCB PPB INTERNAL LABOR	204	210	216	223	230	263	271	279	287	296	2,481
Repl SS liners in coal bunkers								444			444
Big Sandy Receiving Track			590								590
Big Sandy 0 Ash Haul Road	122	139	400	5.149	9,950						15,759
Ash Handling PPB <100k	74				37						111
Combustion Turbine PPB<100k						127	68	127			323
Fuel Delivery PPB<100k						144	67	136	185	185	718
Other Costs PPB<$100k	351	150	204	99	152	607	584	662	306	306	3,420
BSP PPB Env. New	37	37	30	22	59	59	59	59			363
Other Environ Repl <100k	52	74	89	83	254	259	259	274		374	1,719
U 2 PPB Outage <100k						67					67
Rail crossing at coal haul rd							111				111
Repl >500 ft RR track						111		111	148	148	519
Repl of small AC units	71				37	44	59	59	59	85	416
Repl Sta 12 coal sample system						185					185
Reline Feeder Hoppers 13A-D								222			222
Replace Sta 3 Coal Chutes								185	185	204	574
Replace Sta 2 Coal Chutes U0								167	167	204	537
Grand Total	6,708	2,256	10,210	10,211	21,135	5,183	2,471	22,130	1,448	4,302	86,054

Kentucky Power Construction Expenditures
2004 - 2011 Actuals -- Excluding AFUDC & Environmental

Dollars in thousands

Function	2004	2005	2006	2007	2008	2009	2010	2011
Generation	8,773	5,817	11,835	17,921	48,534	8,865	3,556	6,068
Transmission	4,176	7,144	12,589	15,647	25,446	9,655	13,440	20,850
Distribution	22,552	34,228	45,080	41,246	48,478	38,861	31,066	38,501
Sum:	**35,501**	**47,189**	**69,504**	**74,814**	**122,459**	**57,380**	**48,062**	**65,419**

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, Table 1 and pages 23 to 30. Has the Company considered any other alternatives aside from Options 1-4?

a. If so, please provide detailed descriptions of all other alternatives considered, the level to which they were considered (i.e. discussion only, analysis, modeling, etc…), and any analytical work, such that it exists, that examined the cost efficacy of these other alternatives.

b. If so, please provide any analytical work that supports the non-consideration of those alternatives in the final four options presented here.

c. If not, why not?

d. Has the Company considered the cost effectiveness of replacing Big Sandy with capacity-only replacement, such as combustion turbine without combined cycle capacity?

e. Has the Company considered the cost effectiveness of replacing Big Sandy with a mixture of capacity and energy resources, such as a mix of combustion turbines and combined cycle capacity?

f. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and renewable energy purchases in either the short or long-term (i.e. immediately, up to 5 years as in Option 4A, or up to 10 years as in Option 4B)?

g. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and energy efficiency, demand response, or other demand-side management acquisitions or programs?

h. If the answer to any of (d)-(e) is yes, and as not otherwise provided in answer to (a) or (b), please provide any workpapers showing the scenario considered, the expected costs of the scenario, and any model results from comparing the scenario against other alternatives.

RESPONSE

a. An additional evaluation was performed in January of 2012, after the filing of this case. This assessment focused on the possibility of either acquiring --or entering into a purchase power arrangement-- from affiliate Ohio Power Company for a portion of the Mitchell Unit 1 and/or Unit 2 facilities. These 770 MW and 790 MW, respective coal-fired units are located in Moundsville, West Virginia and have recently been environmentally-controlled with FGDs and SCRs. The timing of this alternative evaluation was based on the recent prospect that Ohio Power Company could become corporately separated and, with that, the generation assets of that company may no longer be regulated and, hence, may be available for sale/transfer.

One of these evaluations calls for the purchase of a 20% portion of the combined Mitchell Units 1 and 2 (or, a total of 312 MW) and is under consideration as a replacement for the proposed retirement of KPCo's Big Sandy Unit 1. This evaluation is intended to be introduced as a proposed component of the 'Section 205' filing with the FERC that AEP is intending to file in early 2012 that would seek to modify the AEP Interconnection (Pool) Agreement.

Additionally, KPCo management also requested that an additional analysis be performed under which Kentucky Power would seek to receive a greater portion from Mitchell Units 1 and 2 (ostensibly, one of the 'full' Mitchell units) that would serve to effectively be substituted for the like-sized Big Sandy 2. This evaluation also assumed that in lieu of retiring Big Sandy Unit 1, it would consider converting that unit to burn solely natural gas (i.e. it would become a "gas-steam" unit).

The attachment to this response is a summary of these indicative Strategist-based evaluations performed in January 2012.

b. As indicated in the response part a of this question, this assessment was performed after this KPCo filing, but does not change the results and recommendation of the filing.

c. N/A

d. The Company has not considered the replacement of Big Sandy 2 with a combustion turbine unit. If Big Sandy Unit 2 were to be retired, KPCo would be replacing a large "baseload" facility that has historically contributed significant amounts of generated energy. As such, if it were to replaced purely with peaking capability --in the form of natural gas combustion turbine (CT) units, or as a unit simply converted to burn natural gas (i.e., a gas-steam unit)--, the Company believes it could be exposed to unacceptable levels of market (energy) purchases and, with that, potential for price volatility for the long-term life of the CTs/gas conversion due to such facilities' would very likely have very low utilization/capacity factors.

e. No. However, this option is essentially captured by, particularly, Options #4A and #4B. See the response Sierra Club 1-51, part a, for an elaboration.

f. No. The Company believes that renewable energy purchases are not substitutable for, particularly, capacity planning purposes. For instance, the PJM RTO recognizes only 13% of the nameplate MW-capacity of wind generating sources for capacity planning purposes. Further, KPCo 2009 request to recover its costs under a proposed wind renewable energy purchase agreement (REPA) was denied by the Commission following opposition by KIUC and the Attorney General.

g. No. While as indicated on Table 1-2 of Exhibit SCW-1, KPCo is projected to achieve 41 MW of demand response (DR) resource by 2016, and at least 60 MW by 2020, such amounts would likely serve to merely adjunct KPCo's resource portfolio, rather than offer a major contribution. As with peaking resources, DR would not contribute much in the way of *energy* contribution. Likewise, that same Table 1-2 of Exhibit SCW-1 also indicates as much as nearly 100 GWh of (annual) energy efficiency contribution being projected for the Company by 2016. However, that level also represents a small (< 2%) percentage of KPCo's overall internal load estimate for that year.

h. N/A

WITNESS: Scott C Weaver

DRAFT

CONFIDENTIAL AND BUSINESS SENSITIVE

KPCo ('Stand-Alone') Expansion Plan Summary
Big Sandy Unit Disposition Analysis
Capacity Resource Optimization Under FT-CSAPR (Base) Pricing

	(1) *"Proposed POOL Case"* 312 MW Mitchell + BS2 Retrofit	(2) *"BS2 (FGD) & BS1 (Retire) Substitute"* BS1 GC + Mitchell Unit + BS2 Retire	(3) *"BS1 Retirement Substitute"* Big Sandy 1 Gas Conv + BS2 Retrofil
2011			
2012			
2013			
2014	Mitchell 1 156 MW Transfer Mitchell 2 156-MW Transfer	Mitchell 1 770 MW Transfer	
2015	Big Sandy 1 Retirement	Big Sandy 1 Gas Conversion Big Sandy 2 Retirement	Big Sandy 1 Gas Conversion
2016	**Big Sandy 2 Retrofit**		**Big Sandy 2 Retrofit**
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026		**1- 407 MW CC,**	
2027			**1- 407 MW CC,**
2028			
2029	**1- 407 MW CC,**		
2030-2040			

FTCA_CSAPR (Base) Pricing *CPW Revenue Requirements (2011-2040) ($000):*			
CPW (<u>Before</u> ICAP)	6,877,651	6,671,123	6,806,258
***Less*: ICAP Revenue**	<u>93,142</u>	<u>169,786</u>	<u>90,993</u>
= Total CPW	$6,784,509	$6,501,338	$6,715,266

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retirement; Big Sandy 1 Gas Conversion + 800 MW Mitchell 1

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	198,123	(12,786)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0
2012	250,465	(21,183)	95,924	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0
2013	227,817	(30,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0
2014	370,819	(33,189)	235,220	168,787	607	207,554	208,161	376,948	80,984	457,932	23,973	433,959	988,317	607
2015	232,383	(40,192)	1,796	270,779	7,495	(55,745)	(49,250)	221,529	6,840	228,369	1,541	226,828	1,151,148	7,495
2016	239,635	(41,534)	9,094	272,075	43,471	143,782	187,253	459,328	3,010	462,338	6,103	456,235	1,452,616	43,471
2017	256,716	(41,132)	23,276	274,573	43,471	148,321	191,792	466,365	1,926	468,291	6,413	461,878	1,733,539	43,471
2018	266,234	(40,562)	33,969	272,826	43,471	151,259	194,730	467,556	822	468,379	4,924	463,455	1,993,004	43,471
2019	258,273	(40,954)	2,675	296,552	43,471	181,052	224,523	521,075	767	521,842	5,154	516,688	2,259,267	43,471
2020	276,540	(41,352)	40,194	277,697	50,802	170,834	221,636	499,333	0	499,333	5,415	493,918	2,493,554	50,802
2021	271,096	(55,313)	21,176	305,233	50,802	177,313	228,115	533,348	0	533,348	5,940	527,409	2,723,830	50,802
2022	262,567	(56,327)	17,461	301,433	50,802	183,247	234,049	535,482	100,511	635,993	5,136	630,857	2,977,368	50,802
2023	256,112	(57,232)	(21,136)	334,480	50,802	188,217	239,019	573,498	94,311	667,809	4,732	663,078	3,222,663	50,802
2024	270,651	(58,007)	(379)	329,037	50,802	196,426	247,228	576,264	100,481	676,745	3,786	672,959	3,451,814	50,802
2025	283,695	(58,378)	8,636	333,437	50,802	202,024	252,826	586,263	104,377	690,641	1,551	689,089	3,667,796	50,802
2026	354,358	(55,533)	112,032	297,860	155,248	225,950	381,198	679,057	110,179	789,237	55,194	734,043	3,879,571	155,248
2027	383,658	(56,074)	155,862	283,871	155,248	237,069	392,317	676,187	121,192	797,380	54,861	742,518	4,076,755	155,248
2028	385,292	(56,770)	142,999	299,063	155,248	244,721	399,969	699,033	120,354	819,387	54,267	765,120	4,263,782	155,248
2029	382,751	(57,450)	110,902	329,299	155,248	250,476	405,724	735,024	114,858	849,881	53,273	796,608	4,443,020	155,248
2030	411,585	(57,924)	158,745	310,764	155,248	261,356	416,604	727,368	126,314	853,682	51,461	802,222	4,609,165	155,248
2031	408,663	(58,778)	118,090	349,352	155,248	266,315	421,563	770,915	118,051	888,966	49,816	839,150	4,769,137	155,248
2032	431,023	(59,350)	165,244	325,129	155,248	275,844	431,092	756,222	131,840	888,062	48,769	839,293	4,916,412	155,248
2033	428,310	(60,025)	140,856	347,478	155,248	280,317	435,565	783,043	128,420	911,463	45,588	865,875	5,056,268	155,248
2034	446,367	(60,747)	164,535	342,579	155,248	287,711	442,959	785,539	135,533	921,071	44,961	876,110	5,186,523	155,248
2035	440,665	(61,749)	126,688	375,726	155,248	291,090	446,338	822,064	129,356	951,420	44,113	907,307	5,310,688	155,248
2036	439,500	(62,806)	104,986	397,320	155,248	290,794	446,042	843,362	127,484	970,845	42,829	928,017	5,427,588	155,248
2037	469,231	(63,314)	157,778	374,766	155,248	296,221	451,469	826,235	140,402	966,637	40,547	926,090	5,534,967	155,248
2038	466,767	(64,282)	137,255	393,794	155,248	304,809	460,057	853,851	138,893	992,744	38,869	953,876	5,636,771	155,248
2039	469,416	(65,091)	118,176	416,331	155,248	303,616	458,864	875,195	136,448	1,011,643	37,340	974,303	5,732,487	155,248
2040	481,348	(66,264)	133,129	414,484	155,248	1,064,459	1,219,707	1,634,191	142,572	1,776,763	37,939	1,738,824	5,889,723	155,248
2011 Net Present Value														
Period of 2011-2040	3,373,503	(487,479)	768,629	3,092,352	627,175	1,671,369	2,298,544	5,390,897	668,612	6,059,508	169,786	5,889,723		
Base Case O&M 2011-2040							611,615			611,615	0	611,615		
Utility Cost Present Value 2011-2040							2,910,159			6,671,123	169,786	6,501,338		

Year	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	775	595
2015	20	1,507
2016	59	1,973
2017	75	1,652
2018	67	1,403
2019	63	1,572
2020	59	1,774
2021	58	1,960
2022	46	2,129
2023	40	2,280
2024	30	2,412
2025	12	2,524
2026	406	2,615
2027	393	2,685
2028	382	2,731
2029	372	2,751
2030	361	2,745
2031	346	2,765
2032	337	2,785
2033	313	2,805
2034	306	2,825
2035	298	2,845
2036	287	2,866
2037	270	2,887
2038	257	2,907
2039	245	2,928
2040	247	2,949

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retirement; Big Sandy 1 Gas Conversion + 800 MW Mitchell 1

	SO2 Emissions Total East	NSR Adjusted Total [B]	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,635)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	4,503	38,114	6,593	(31,521)	10,061	5,564	0.28
2015	6,932	0	6,593	6,593	6,138	3,814	0.04
2016	3,545	0	6,593	6,593	6,317	3,241	0.03
2017	3,877	0	6,593	6,593	6,725	3,517	0.03
2018	3,840	0	6,593	6,593	6,940	3,530	0.03
2019	3,212	0	6,593	6,593	6,404	3,245	0.03
2020	4,449	0	6,593	6,593	7,153	2,649	0.03
2021	4,277	0	6,593	6,593	6,707	2,535	0.03
2022	4,261	0	6,593	6,593	6,666	2,426	0.03
2023	3,997	0	6,593	6,593	6,173	2,314	0.02
2024	3,422	0	6,593	6,593	6,493	2,400	0.03
2025	4,327	0	6,593	6,593	6,659	2,453	0.03
2026	3,756	0	6,593	6,593	6,936	2,402	0.03
2027	4,301	0	6,593	6,593	7,535	2,585	0.03
2028	3,679	0	6,593	6,593	7,387	2,546	0.03
2029	4,241	0	6,593	6,593	6,961	2,410	0.03
2030	4,163	0	6,593	6,593	7,554	2,606	0.03
2031	3,397	0	6,593	6,593	6,969	2,467	0.03
2032	4,423	0	6,593	6,593	7,683	2,650	0.03
2033	4,243	0	6,593	6,593	7,388	2,535	0.03
2034	4,410	0	6,593	6,593	7,697	2,601	0.03
2035	4,153	0	6,593	6,593	7,251	2,444	0.03
2036	3,603	0	6,593	6,593	7,054	2,366	0.03
2037	4,410	0	6,593	6,593	7,669	2,518	0.03
2038	3,823	0	6,593	6,593	7,489	2,448	0.03
2039	4,451	0	6,593	6,593	7,262	2,344	0.03
2040	3,790	0	6,593	6,593	7,490	2,396	0.03

	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	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	1,036	4,717	3,682	6,894	301,823	735,782	10.7	16.1%
2015	7,479	139	23	(116)	1,465	792	(674)	6,903	310,633	537,461	7.8	3.3%
2016	7,488	139	19	(120)	1,145	705	(440)	6,911	313,409	769,644	11.1	10.3%
2017	7,505	139	28	(111)	865	821	(43)	6,927	321,132	783,009	11.3	8.8%
2018	7,536	139	37	(102)	772	913	141	6,955	332,128	795,582	11.4	7.7%
2019	7,571	139	36	(103)	1,096	687	(409)	6,988	337,451	854,139	12.2	7.6%
2020	7,604	139	34	(105)	601	898	298	7,019	340,282	834,200	11.9	6.4%
2021	7,648	288	34	(254)	874	847	(27)	7,059	347,477	874,886	12.4	6.1%
2022	7,695	288	34	(254)	953	735	(218)	7,102	349,845	980,702	13.8	6.6%
2023	7,744	288	34	(254)	1,255	499	(757)	7,148	360,647	1,023,725	14.3	6.4%
2024	7,798	289	34	(255)	1,126	630	(496)	7,198	365,998	1,038,958	14.4	5.9%
2025	7,846	288	34	(254)	1,062	723	(339)	7,242	368,701	1,057,791	14.6	5.6%
2026	7,896	288	34	(254)	822	1,621	799	7,288	377,102	1,111,144	15.2	5.5%
2027	7,947	288	34	(254)	699	2,040	1,341	7,335	387,215	1,129,733	15.4	5.2%
2028	7,999	289	34	(255)	794	1,903	1,109	7,383	389,382	1,154,502	15.6	5.0%
2029	8,044	288	34	(254)	820	1,554	734	7,425	399,077	1,195,685	16.1	4.9%
2030	8,093	288	34	(254)	687	1,947	1,260	7,470	406,645	1,208,866	16.2	4.6%
2031	8,143	288	34	(254)	916	1,657	741	7,516	414,203	1,253,352	16.7	4.6%
2032	8,195	289	34	(255)	674	1,948	1,274	7,564	421,901	1,261,194	16.7	4.3%
2033	8,241	288	34	(254)	752	1,716	965	7,606	429,743	1,295,617	17.0	4.2%
2034	8,289	288	34	(254)	670	1,851	1,181	7,651	437,730	1,313,840	17.2	4.1%
2035	8,339	288	34	(254)	891	1,603	712	7,697	445,866	1,353,173	17.6	4.0%
2036	8,389	289	34	(255)	853	1,345	492	7,743	454,153	1,382,169	17.9	3.9%
2037	8,439	288	34	(254)	708	1,709	1,001	7,789	462,594	1,388,683	17.8	3.8%
2038	8,488	288	34	(254)	824	1,542	718	7,835	471,191	1,425,067	18.2	3.7%
2039	8,538	288	34	(254)	839	1,381	542	7,881	479,949	1,454,252	18.5	3.6%
2040	8,589	289	34	(255)	823	1,424	601	7,927	488,869	2,227,694	28.1	5.0%

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	2,118		0	2,118	70.4%
2015	1,234	1,353		0	1,353	9.6%
2016	1,213	1,370		0	1,370	12.9%
2017	1,198	1,369		0	1,369	14.3%
2018	1,207	1,371		0	1,371	13.6%
2019	1,218	1,379		0	1,379	13.2%
2020	1,224	1,381		0	1,381	12.8%
2021	1,238	1,396		0	1,396	12.7%
2022	1,249	1,396		0	1,396	11.8%
2023	1,255	1,396		0	1,396	11.2%
2024	1,264	1,396		0	1,396	10.4%
2025	1,281	1,396		0	1,396	9.0%
2026	1,293	1,396	1- 407 MW CC,	407	1,803	39.4%
2027	1,305	1,396		407	1,803	38.1%
2028	1,315	1,396		407	1,803	37.1%
2029	1,324	1,396		407	1,803	36.2%
2030	1,335	1,396		407	1,803	35.0%
2031	1,348	1,396		407	1,803	33.7%
2032	1,357	1,396		407	1,803	32.9%
2033	1,372	1,388		407	1,795	30.8%
2034	1,378	1,388		407	1,795	30.2%
2035	1,389	1,392		407	1,799	29.5%
2036	1,399	1,392		407	1,799	28.6%
2037	1,415	1,392		407	1,799	27.1%
2038	1,427	1,392		407	1,799	26.1%
2039	1,438	1,392		407	1,799	25.1%
2040	1,436	1,392		407	1,799	25.3%

[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

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KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit; Big Sandy 1 Gas Conversion

Optimal Plan Cost Summary ($000)

					Base Rate Impacts									
Annual Costs	Fuel Cost (A)	Contract Revenue (B)	Market Revenue/(Cost) (C)	Fuel & Transactions (D)=(A)-(B)-(C)	Carrying Charges (E)	Incremental O&M (F)	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	198,123	(12,788)	40,914	169,997	0	0	0	169,997	7,418	177,415	0	177,415	177,415	0
2012	250,465	(21,183)	95,924	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0
2013	227,817	(30,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0
2014	276,579	(38,222)	58,238	256,563	607	1	608	257,171	102,599	359,770	1,379	358,392	929,383	607
2015	313,124	(41,141)	67,668	286,597	7,495	69	7,564	294,161	30,078	324,240	3,244	320,996	1,159,814	7,495
2016	225,429	(40,937)	(35,333)	301,699	154,650	77,211	231,861	533,560	3,366	536,926	(68,819)	605,745	1,560,073	154,650
2017	278,650	(41,707)	60,299	260,058	154,650	138,147	292,797	552,855	2,195	555,049	7,649	547,400	1,893,013	154,650
2018	299,074	(41,660)	83,918	256,817	154,650	150,147	304,797	561,614	937	562,552	5,687	556,865	2,204,774	154,650
2019	289,254	(42,988)	59,521	272,721	154,650	141,597	296,247	568,968	867	569,834	5,686	564,148	2,495,494	154,650
2020	304,884	(43,874)	84,088	264,670	161,981	142,449	304,430	569,100	0	569,100	5,652	563,448	2,762,761	161,981
2021	311,796	(58,061)	90,667	279,189	161,981	146,573	308,554	587,743	0	587,743	6,202	581,541	3,016,673	161,981
2022	304,049	(58,825)	85,853	277,021	161,981	147,596	309,577	586,598	112,825	699,423	5,421	694,003	3,295,589	161,981
2023	278,671	(59,395)	18,173	319,893	161,981	145,084	307,065	626,958	100,960	727,918	5,037	722,882	3,563,007	161,981
2024	307,004	(60,848)	63,463	304,389	161,981	155,822	317,803	622,191	111,565	733,756	4,109	729,647	3,811,461	161,981
2025	307,267	(61,721)	47,040	321,948	161,981	154,390	316,371	638,320	110,685	749,005	1,889	747,116	4,045,631	161,981
2026	324,829	(62,426)	65,345	321,911	161,981	164,233	326,214	648,125	116,179	764,304	194	764,110	4,266,081	161,981
2027	399,598	(56,662)	181,980	274,280	268,046	183,925	451,971	726,251	124,462	850,713	55,220	795,492	4,477,332	268,046
2028	414,405	(57,403)	200,153	271,655	268,046	194,769	462,815	734,470	129,925	864,394	54,632	809,762	4,675,271	268,046
2029	416,162	(58,140)	187,570	286,732	268,046	199,644	467,690	754,422	129,116	883,537	53,641	829,896	4,861,999	268,046
2030	422,920	(58,625)	173,152	308,393	268,046	197,565	465,611	774,004	126,187	900,190	51,828	848,362	5,037,701	268,046
2031	436,639	(59,529)	194,229	301,939	156,867	162,923	319,790	621,729	133,114	754,843	50,186	704,657	5,172,034	156,867
2032	457,763	(60,046)	223,963	293,846	156,867	165,817	322,684	616,530	140,778	757,308	49,141	708,166	5,296,299	156,867
2033	464,172	(60,827)	220,610	304,389	156,867	166,814	323,681	628,069	142,018	770,087	45,963	724,124	5,413,259	156,867
2034	452,558	(61,666)	173,149	341,075	156,867	163,519	320,386	661,461	133,662	795,123	45,339	749,784	5,524,733	156,867
2035	464,783	(62,941)	185,637	342,087	156,867	177,050	333,917	676,004	139,139	815,143	44,494	770,649	5,630,196	156,867
2036	473,961	(63,849)	190,702	347,108	156,867	181,724	338,591	685,698	142,244	827,942	43,212	784,730	5,729,046	156,867
2037	488,429	(64,557)	206,812	346,174	156,867	185,627	342,494	688,668	147,957	836,624	40,934	795,691	5,821,306	156,867
2038	486,507	(65,710)	185,141	367,076	156,867	189,847	346,714	713,790	146,195	859,985	39,257	820,728	5,908,900	156,867
2039	499,903	(66,588)	199,102	367,389	156,867	195,459	352,326	719,715	151,163	870,878	37,732	833,147	5,990,748	156,867
2040	500,140	(67,912)	179,681	388,371	156,867	592,256	749,123	1,137,494	149,397	1,286,891	38,333	1,248,558	6,103,651	156,867
2011 Net Present Value														
Period of 2011-2040	3,518,373	(503,939)	963,750	3,058,561	1,257,990	1,140,873	2,398,863	5,457,424	737,219	6,194,644	90,993	6,103,651		
Base Case O&M 2011-2040							611,615			611,615	0	611,615		
Utility Cost Present Value 2011-2040							3,010,478			6,806,258	90,993	6,715,266		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	45	595
2015	41	1,507
2016	(571)	1,973
2017	89	1,652
2018	78	1,403
2019	70	1,572
2020	61	1,774
2021	61	1,960
2022	49	2,129
2023	42	2,280
2024	33	2,412
2025	14	2,524
2026	1	2,615
2027	396	2,685
2028	385	2,731
2029	375	2,751
2030	363	2,745
2031	349	2,765
2032	339	2,785
2033	315	2,805
2034	309	2,825
2035	301	2,845
2036	290	2,866
2037	273	2,887
2038	260	2,907
2039	248	2,928
2040	250	2,949

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KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit; *Big Sandy 1 Gas Conversion*

	SO2 Emissions Total East	NSR Adjusted Total B	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	5,050	49,726	6,593	(43,133)	7,010	5,319	0.33
2015	9,351	38,249	6,593	(31,656)	7,569	5,001	0.27
2016	4,097	1,150	6,593	5,443	5,590	3,309	0.15
2017	4,430	2,042	6,593	4,551	7,280	3,905	0.26
2018	4,358	2,125	6,593	4,468	7,703	4,022	0.27
2019	3,557	2,022	6,593	4,571	7,259	3,664	0.26
2020	4,573	2,100	6,593	4,493	7,741	3,011	0.26
2021	4,372	2,096	6,593	4,497	7,724	3,006	0.26
2022	4,559	1,985	6,593	4,608	7,482	2,879	0.25
2023	4,269	1,738	6,593	4,855	6,608	2,568	0.22
2024	3,655	1,990	6,593	4,603	7,209	2,786	0.25
2025	4,559	1,791	6,593	4,802	7,061	2,726	0.23
2026	3,917	1,989	6,593	4,604	7,314	2,826	0.25
2027	4,558	1,896	6,593	4,697	7,739	2,648	0.24
2028	3,884	2,111	6,593	4,482	7,975	2,727	0.26
2029	4,401	2,108	6,593	4,485	7,825	2,686	0.26
2030	4,332	1,823	6,593	4,770	7,546	2,636	0.23
2031	3,536	2,115	6,593	4,478	7,858	2,714	0.27
2032	4,572	2,127	6,593	4,466	8,204	2,813	0.27
2033	4,374	2,118	6,593	4,475	8,170	2,782	0.27
2034	4,558	1,825	6,593	4,768	7,591	2,578	0.23
2035	4,270	2,112	6,593	4,481	7,799	2,623	0.26
2036	3,658	2,122	6,593	4,471	7,871	2,621	0.27
2037	4,559	2,104	6,593	4,489	8,082	2,643	0.26
2038	3,917	2,101	6,593	4,492	7,882	2,560	0.26
2039	4,558	2,104	6,593	4,489	8,046	2,577	0.26
2040	3,886	2,099	6,593	4,494	7,849	2,508	0.26

	Summary of Energy Purchases and Sales (Gwh)										TOTAL RATE IMPACT	
	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)	(cents / kWh)	CAGR (thru)
2011	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	690	1,367	678	6,894	301,823	660,215	9.6	11.9%
2015	7,479	139	23	(116)	225	1,524	1,299	6,903	310,633	631,629	9.2	7.6%
2016	7,488	139	19	(120)	1,908	1,019	(889)	6,911	313,409	919,154	13.3	14.3%
2017	7,505	139	28	(111)	213	1,175	962	6,927	321,132	868,531	12.5	10.7%
2018	7,536	139	37	(102)	103	1,503	1,400	6,955	332,128	888,993	12.8	9.4%
2019	7,571	139	36	(103)	229	1,120	891	6,988	337,451	901,599	12.9	8.3%
2020	7,604	139	34	(105)	115	1,490	1,376	7,019	340,282	903,730	12.9	7.3%
2021	7,648	288	34	(254)	101	1,563	1,462	7,059	347,477	929,018	13.2	6.8%
2022	7,695	288	34	(254)	234	1,364	1,130	7,102	349,845	1,043,847	14.7	7.2%
2023	7,744	288	34	(254)	597	700	104	7,148	360,647	1,083,528	15.2	6.9%
2024	7,798	289	34	(255)	282	1,013	731	7,198	365,998	1,095,646	15.2	6.4%
2025	7,846	288	34	(254)	437	951	514	7,242	368,701	1,115,817	15.4	6.0%
2026	7,896	288	34	(254)	302	1,061	760	7,288	377,102	1,141,211	15.7	5.7%
2027	7,947	288	34	(254)	225	2,228	2,003	7,335	387,215	1,182,707	16.1	5.5%
2028	7,999	289	34	(255)	155	2,315	2,161	7,383	389,382	1,199,144	16.2	5.2%
2029	8,044	288	34	(254)	181	2,119	1,938	7,425	399,077	1,228,973	16.6	5.0%
2030	8,093	288	34	(254)	377	2,091	1,714	7,470	406,645	1,255,007	16.8	4.9%
2031	8,143	288	34	(254)	185	2,088	1,903	7,516	414,203	1,118,859	14.9	4.0%
2032	8,195	289	34	(255)	112	2,341	2,229	7,564	421,901	1,130,067	14.9	3.8%
2033	8,241	288	34	(254)	157	2,293	2,136	7,606	429,743	1,153,866	15.2	3.7%
2034	8,289	288	34	(254)	361	1,881	1,520	7,651	437,730	1,187,513	15.5	3.6%
2035	8,339	288	34	(254)	227	1,826	1,599	7,697	445,866	1,216,515	15.8	3.6%
2036	8,389	289	34	(255)	220	1,834	1,614	7,743	454,153	1,238,883	16.0	3.5%
2037	8,439	288	34	(254)	190	1,954	1,764	7,789	462,594	1,258,284	16.2	3.4%
2038	8,488	288	34	(254)	206	1,678	1,472	7,835	471,191	1,291,919	16.5	3.3%
2039	8,538	288	34	(254)	169	1,752	1,583	7,881	479,949	1,313,096	16.7	3.2%
2040	8,589	289	34	(255)	284	1,591	1,308	7,927	488,869	1,737,427	21.9	4.1%

	East Reserve Margin - MW					
	Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,387		0	1,387	11.6%
2015	1,234	1,375		0	1,375	11.4%
2016	1,213	640	1 -737 MW Retrofit,	0	640	-47.3%
2017	1,198	1,383		0	1,383	15.5%
2018	1,207	1,382		0	1,382	14.5%
2019	1,218	1,385		0	1,385	13.7%
2020	1,224	1,384		0	1,384	13.0%
2021	1,238	1,398		0	1,398	13.0%
2022	1,249	1,398		0	1,398	12.0%
2023	1,255	1,398		0	1,398	11.4%
2024	1,264	1,398		0	1,398	10.6%
2025	1,281	1,398		0	1,398	9.2%
2026	1,293	1,398		0	1,398	8.1%
2027	1,305	1,398	1- 407 MW CC,	407	1,805	38.3%
2028	1,315	1,398		407	1,805	37.3%
2029	1,324	1,398		407	1,805	36.4%
2030	1,335	1,398		407	1,805	35.2%
2031	1,348	1,398		407	1,805	33.9%
2032	1,357	1,398		407	1,805	33.0%
2033	1,372	1,390		407	1,797	31.0%
2034	1,378	1,390		407	1,797	30.4%
2035	1,389	1,394		407	1,801	29.7%
2036	1,399	1,394		407	1,801	28.8%
2037	1,415	1,394		407	1,801	27.3%
2038	1,427	1,394		407	1,801	26.2%
2039	1,438	1,394		407	1,801	25.3%
2040	1,436	1,394		407	1,801	25.4%

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

Resource Planning
Created on: December 6, 2011

00401_Sierra Club_1-52A (alternative option 1)
FTCASPR BS1-Gas-Conv

DRAF

KENTUCKY POWER COMPANY
KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit Mitchell capacity transfer updated NBV and CCR+ESP

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	198,123	(12,728)	40,914	169,997	0	0	0	.169,997	7,418	177,415	0	177,415	177,415	0
2012	250,465	(21,183)	95,924	175,725	0	0	0	175,725	86,954	262,680	0	262,680	419,204	0
2013	227,817	(39,153)	37,371	220,599	0	(0)	(0)	220,599	51,659	272,258	0	272,258	649,879	0
2014	350,000	(33,880)	158,966	224,914	607	43,445	44,052	268,966	101,654	370,620	10,478	360,142	930,748	607
2015	320,896	(42,834)	124,351	239,378	607	54,613	55,220	294,598	26,925	321,524	5,376	316,147	1,157,699	607
2016	231,962	(42,286)	25,544	248,704	147,762	138,521	286,283	534,987	2,582	537,569	(66,028)	603,597	1,556,538	147,762
2017	303,794	(43,832)	139,589	208,037	147,762	197,837	345,599	553,636	1,726	555,361	9,987	545,374	1,888,246	147,762
2018	322,684	(43,247)	161,963	203,968	147,762	212,072	359,834	563,802	719	564,521	7,672	556,849	2,199,998	147,762
2019	312,469	(45,954)	138,149	220,274	147,762	215,849	363,611	583,885	671	584,557	7,911	576,646	2,497,159	147,762
2020	319,776	(45,154)	156,120	208,811	155,093	206,953	362,046	570,857	0	570,857	8,162	562,695	2,764,069	155,093
2021	322,725	(59,857)	160,572	222,010	155,093	213,965	369,058	591,068	0	591,068	8,975	582,093	3,018,221	155,093
2022	316,120	(61,963)	168,358	209,725	155,093	217,138	372,231	581,957	133,249	715,205	8,433	706,772	3,302,270	155,093
2023	307,371	(64,740)	126,629	245,483	155,093	220,741	375,834	621,317	127,637	748,955	8,263	740,692	3,576,276	155,093
2024	333,926	(64,299)	170,869	227,355	155,093	231,247	386,340	613,695	137,198	750,893	7,522	743,371	3,829,403	155,093
2025	330,379	(66,332)	151,452	245,259	155,093	231,872	386,965	632,225	136,069	768,294	5,460	762,833	4,068,499	155,093
2026	355,592	(67,014)	179,960	242,646	155,093	244,599	399,692	642,337	143,948	786,285	3,894	782,391	4,294,223	155,093
2027	340,722	(57,099)	146,115	261,705	155,093	241,969	397,062	658,767	138,748	797,515	2,189	795,327	4,505,431	155,093
2028	363,088	(69,799)	171,153	261,734	155,093	254,538	409,631	671,365	145,082	816,447	692	815,756	4,704,835	155,093
2029	459,846	(58,172)	307,355	210,663	264,472	282,660	547,132	757,795	157,615	915,410	57,534	857,876	4,897,858	264,472
2030	457,341	(59,977)	289,770	227,548	264,472	281,087	545,559	773,107	154,144	927,251	55,712	871,539	5,078,360	264,472
2031	471,751	(59,826)	307,014	224,563	153,293	246,572	399,865	624,428	159,870	784,298	54,099	730,199	5,217,562	153,293
2032	495,442	(59,078)	339,458	216,062	153,293	249,918	403,211	619,274	168,281	787,555	53,082	734,473	5,346,443	153,293
2033	504,030	(60,707)	340,892	223,845	153,293	251,700	404,993	628,839	170,456	799,295	49,932	749,362	5,467,480	153,293
2034	496,330	(63,430)	304,608	255,152	153,293	248,323	401,616	656,769	164,513	821,282	49,336	771,946	5,582,249	153,293
2035	502,499	(63,455)	304,039	261,915	153,293	258,588	411,881	673,796	167,133	840,929	48,519	792,410	5,690,690	153,293
2036	517,130	(63,957)	316,345	264,743	153,293	262,350	415,643	680,386	171,977	852,363	47,267	805,096	5,792,105	153,293
2037	531,462	(64,635)	335,084	261,013	153,293	264,140	417,433	678,446	178,076	856,521	45,019	811,503	5,886,198	153,293
2038	528,923	(65,912)	310,525	284,310	153,293	267,323	420,616	704,926	175,916	880,842	43,371	837,471	5,975,579	153,293
2039	538,732	(66,775)	320,397	285,111	153,293	269,385	422,678	707,789	180,050	887,838	41,875	845,964	6,058,687	153,293
2040	552,030	(68,920)	320,496	299,554	153,293	670,027	823,320	1,122,874	182,613	1,305,487	42,506	1,262,980	6,172,894	153,293
2011 Net Present Value														
Period of 2011-2040	3,722,246	(521,473)	1,696,161	2,547,563	1,154,839	1,728,777	2,883,617	5,431,180	834,857	6,266,036	93,142	6,172,894		
Base Case O&M 2011-2040							611,615			611,615	0	611,615		
Utility Cost Present Value 2011-2040							3,495,231			6,877,651	93,142	6,784,509		

	Surplus MW	ICAP Value $/MW-Wk
2011	0	958
2012	0	388
2013	0	161
2014	339	595
2015	69	1,507
2016	(644)	1,973
2017	116	1,652
2018	105	1,403
2019	97	1,572
2020	88	1,774
2021	88	1,960
2022	76	2,129
2023	70	2,280
2024	60	2,412
2025	42	2,524
2026	29	2,615
2027	16	2,685
2028	5	2,731
2029	402	2,751
2030	390	2,745
2031	376	2,765
2032	367	2,785
2033	342	2,805
2034	336	2,825
2035	328	2,845
2036	317	2,866
2037	300	2,887
2038	287	2,907
2039	275	2,928
2040	277	2,949

KPSC Case No. 2011-00401
Sierra Club's First Set of Data Requests
Dated January 13, 2012
Item No. 52
Attachment 1
Page 6 of 7

DR´

KPCo Capacity Resource Optimization
Costs and Emissions Summary
Levelized FTCA CSAPR Commodity Pricing, Big Sandy 2 Retrofit Mitchell capacity transfer updated NBV and CCR+ESP

	SO2 Emissions Total East	NSR Adjusted Total [B]	NSR SO2 NSR SO2 Caps.	NSR Surplus/(Deficit)	CO2 Emissions Total East	NOX Total East	HG (Tons) East
2011	10,452	41,961	15,325	(26,636)	7,387	6,171	0.29
2012	10,586	49,636	15,325	(34,311)	8,375	6,944	0.34
2013	7,296	43,730	15,325	(28,405)	6,781	5,751	0.29
2014	4,513	49,493	6,593	(42,900)	9,166	5,813	0.34
2015	9,155	34,004	6,593	(27,411)	8,787	4,215	0.25
2016	3,909	1,066	6,593	5,527	7,036	2,540	0.15
2017	4,324	1,895	6,593	4,698	8,889	3,228	0.26
2018	4,254	2,041	6,593	4,552	9,299	3,255	0.28
2019	3,381	1,946	6,593	4,647	8,829	2,885	0.26
2020	4,540	1,855	6,593	4,738	9,094	2,186	0.25
2021	4,350	1,880	6,593	4,713	9,002	2,160	0.25
2022	4,548	1,783	6,593	4,810	8,837	2,119	0.24
2023	4,247	1,705	6,593	4,888	8,354	2,011	0.23
2024	3,646	1,852	6,593	4,741	8,865	2,136	0.25
2025	4,548	1,738	6,593	4,855	8,681	2,080	0.23
2026	3,909	1,967	6,593	4,626	9,062	2,179	0.26
2027	4,558	1,620	6,593	4,973	8,627	2,070	0.22
2028	3,884	1,885	6,593	4,708	8,905	2,141	0.25
2029	4,401	2,027	6,593	4,566	9,552	2,231	0.27
2030	4,332	1,678	6,593	4,915	9,218	2,136	0.23
2031	3,536	1,984	6,593	4,609	9,437	2,204	0.26
2032	4,572	1,993	6,593	4,600	9,807	2,285	0.26
2033	4,374	1,985	6,593	4,608	9,806	2,287	0.26
2034	4,558	1,711	6,593	4,882	9,343	2,168	0.23
2035	4,270	1,992	6,593	4,601	9,368	2,194	0.26
2036	3,658	2,013	6,593	4,580	9,516	2,230	0.27
2037	4,559	1,936	6,593	4,657	9,727	2,279	0.26
2038	3,917	1,973	6,593	4,620	9,485	2,227	0.26
2039	4,558	1,952	6,593	4,641	9,583	2,247	0.26
2040	3,886	1,972	6,593	4,621	9,594	2,259	0.26

	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	7,432	58	115	57	369	1,247	878	6,860	290,923	468,338	6.8	
2012	7,476	138	117	(22)	80	2,136	2,057	6,900	289,285	551,964	8.0	17.2%
2013	7,457	138	36	(102)	807	1,172	365	6,883	294,367	566,624	8.2	9.8%
2014	7,469	139	17	(122)	134	3,049	2,915	6,894	301,823	661,965	9.6	12.0%
2015	7,479	139	23	(116)	108	2,502	2,394	6,903	310,633	626,781	9.1	7.4%
2016	7,488	139	19	(120)	1,243	1,574	331	6,911	313,409	917,006	13.3	14.2%
2017	7,505	139	28	(111)	35	2,509	2,475	6,927	321,132	866,506	12.5	10.6%
2018	7,536	139	37	(102)	25	2,921	2,896	6,955	332,128	888,977	12.8	9.4%
2019	7,571	139	36	(103)	42	2,417	2,375	6,988	337,451	914,097	13.1	8.5%
2020	7,604	139	34	(105)	73	2,661	2,588	7,019	340,282	902,976	12.9	7.3%
2021	7,648	288	34	(254)	43	2,659	2,615	7,059	347,477	929,570	13.2	6.8%
2022	7,695	288	34	(254)	72	2,428	2,356	7,102	349,845	1,056,617	14.9	7.3%
2023	7,744	288	34	(254)	233	2,024	1,790	7,148	360,647	1,101,339	15.4	7.0%
2024	7,798	289	34	(255)	78	2,389	2,311	7,198	365,998	1,109,370	15.4	6.5%
2025	7,846	288	34	(254)	117	2,164	2,046	7,242	368,701	1,131,535	15.6	6.1%
2026	7,896	288	34	(254)	46	2,498	2,452	7,288	377,102	1,159,492	15.9	5.8%
2027	7,947	288	34	(254)	265	2,132	1,866	7,335	387,215	1,182,542	16.1	5.5%
2028	7,999	289	34	(255)	54	2,228	2,174	7,383	389,382	1,205,137	16.3	5.3%
2029	8,044	288	34	(254)	13	3,620	3,607	7,425	399,077	1,256,953	16.9	5.2%
2030	8,093	288	34	(254)	110	3,382	3,272	7,470	406,645	1,278,183	17.1	5.0%
2031	8,143	288	34	(254)	33	3,404	3,371	7,516	414,203	1,144,402	15.2	4.1%
2032	8,195	289	34	(255)	27	3,749	3,722	7,564	421,901	1,156,374	15.3	3.9%
2033	8,241	288	34	(254)	17	3,668	3,651	7,606	429,743	1,179,105	15.5	3.8%
2034	8,289	288	34	(254)	81	3,231	3,150	7,651	437,730	1,209,675	15.8	3.7%
2035	8,339	288	34	(254)	42	3,065	3,023	7,697	445,866	1,238,276	16.1	3.6%
2036	8,389	289	34	(255)	27	3,142	3,115	7,743	454,153	1,259,248	16.3	3.5%
2037	8,439	288	34	(254)	42	3,282	3,240	7,789	462,594	1,274,096	16.4	3.4%
2038	8,488	288	34	(254)	28	2,920	2,891	7,835	471,191	1,308,663	16.7	3.4%
2039	8,538	288	34	(254)	52	2,971	2,919	7,881	479,949	1,325,913	16.8	3.3%
2040	8,589	289	34	(255)	26	2,895	2,868	7,927	488,869	1,751,850	22.1	4.1%

	East Reserve Margin - MW: Demand	Existing Capacity	Expansion Plan	Case Capacity Changes	Total Capacity	Reserve Margin - %
2011	1,033	1,115		0	1,115	8.0%
2012	1,251	1,316		0	1,316	5.2%
2013	1,257	1,317		0	1,317	4.8%
2014	1,243	1,682		0	1,682	35.3%
2015	1,234	1,402		0	1,402	13.6%
2016	1,213	667	1 -737 MW Retrofit,	0	667	-45.0%
2017	1,198	1,411		0	1,411	17.7%
2018	1,207	1,409		0	1,409	16.7%
2019	1,218	1,413		0	1,413	16.0%
2020	1,224	1,411		0	1,411	15.3%
2021	1,238	1,426		0	1,426	15.1%
2022	1,249	1,426		0	1,426	14.1%
2023	1,255	1,426		0	1,426	13.6%
2024	1,264	1,426		0	1,426	12.8%
2025	1,281	1,426		0	1,426	11.3%
2026	1,293	1,426		0	1,426	10.3%
2027	1,305	1,426		0	1,426	9.2%
2028	1,315	1,426		0	1,426	8.4%
2029	1,324	1,426	1- 407 MW CC,	407	1,833	38.4%
2030	1,335	1,426		407	1,833	37.3%
2031	1,348	1,426		407	1,833	35.9%
2032	1,357	1,426		407	1,833	35.0%
2033	1,372	1,418		407	1,825	33.0%
2034	1,378	1,418		407	1,825	32.4%
2035	1,389	1,422		407	1,829	31.6%
2036	1,399	1,422		407	1,829	30.7%
2037	1,415	1,422		407	1,829	29.2%
2038	1,427	1,422		407	1,829	28.1%
2039	1,438	1,422		407	1,829	27.2%
2040	1,436	1,422		407	1,829	27.3%

[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

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, page 11 and 12, page 53 and Exhibit SCW-1 pages 3 to 6.

a. Please indicate the annual capacity and annual generation the Company has obtained by source in each of the most recent 5 calendar years.

b. Please indicate the capacity and annual generation the Company projects it would obtain from Big Sandy Unit 1 in each year, 2011 through 2030, if it were not to retire the unit; if this answer differs for different scenarios, please provide the answer for each scenario.

c. Please provide the Company's projected mix of capacity and generation by source through 2030 under alternative option 1, e.g. capacity and generation from owned units, capacity and generation from the AEP fleet, purchases of firm capacity and of generation.

d. Please provide the Company's projected mix of capacity and generation by source through 2030 under alternative option 2, e.g. capacity and generation from owned units, capacity and generation from the AEP fleet, purchases of firm capacity and of generation.

e. Please provide the Company's projected mix of capacity and generation by source through 2030 under alternative option 3, e.g. capacity and generation from owned units, capacity and generation from the AEP fleet, purchases of firm capacity and of generation.

f. Please provide the Company's projected energy and peak load requirement, broken down by sector, through 2030.

g. At what date in the future does KPC expect to require additional capacity should Big Sandy 2 not be retired?

h. At what date in the future does KPC expect to require additional capacity should Big Sandy 2 be retired?

i. At what date in the future does KPC expect to require additional energy should Big Sandy 2 not be retired?

j. At what date in the future does KPC expect to require additional energy should Big Sandy 2 be retired?

RESPONSE

a. Below is the annual capacity and generation for KPCo's most recent 5 calendar years.

Capacity (MW)	2007	2008	2009	2010	2011
Big Sandy	1,060	1,060	1,060	1,077	1,078
Rockport 1	195	198	198	198	198
Rockport 2	195	195	195	195	195
Total	1,450	1,453	1,453	1,470	1,471
Energy (GWh)					
Coal	7,533	6,021	6,262	6,552	6,373
Other*	1,918	3,097	2,200	2,167	1,859
Total	9,451	9,118	8,462	8,720	8,232

* Net Pool Interchange

b. Below is the capacity and generation by pricing scenario for Option #3 where Big Sandy Unit 1 does not retire but is repowered as a CC unit. This represents the <u>only</u> option evaluated that does not retire Big Sandy Unit 1 effective 2015.

Big Sandy 1

	Nominal Capacity Across all Scenarios	FT-CASPR 'Base' Fleet	FT-CASPR Higer Band	FT-CASPR Lower Band	FT-CASPR Early Carbon	FT-CASPR No Carbon
	MW	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**
2011	278	979	979	979	979	979
2012	278	1,122	1,256	1,084	1,140	1,128
2013	278	1,126	1,244	951	1,003	1,141
2014	278	1,026	782	1,180	1,142	1,016
2015	278	747	744	854	756	754
2016	745	4,252	4,272	4,298	4,243	4,269
2017	745	4,196	4,184	4,244	4,258	4,211
2018	745	4,170	4,167	4,227	4,217	4,186
2019	745	4,190	4,172	4,223	4,231	4,194
2020	745	4,184	4,189	4,239	4,260	4,194
2021	745	4,177	4,152	4,198	4,210	4,186
2022	745	4,224	4,210	4,295	4,211	4,194
2023	745	4,218	4,221	4,314	4,225	4,207
2024	745	4,252	4,219	4,307	4,241	4,221
2025	745	3,501	3,311	3,629	3,490	3,455
2026	745	3,752	3,700	3,836	3,747	3,701
2027	745	3,655	3,491	3,754	3,644	3,612
2028	745	3,761	3,652	3,842	3,758	3,706
2029	745	3,785	3,675	3,857	3,775	3,747
2030	745	3,737	3,525	3,777	3,699	3,659

c. Below is the projected mix of capacity and generation by source for Option #1 (Retrofit Big Sandy 2) under the FT-CSAPR 'Base' commodity pricing scenario.

Option 1 FT-CASPR 'Base' Fleet	KPCo Installed Capacity MW	PJM Market Firm Capacity Purchases MW	KPCo Total Thermal Generation GWh	PJM Market Purchases GWh	KPCo Contract Purchases GWh
2011	1,115	0	8,280	369	58
2012	1,316	0	9,438	80	138
2013	1,317	0	7,657	807	138
2014	1,387	0	7,961	690	139
2015	1,108	225	8,234	260	139
2016	373	938	5,691	2,373	139
2017	1,116	178	7,809	307	139
2018	1,115	189	8,275	154	139
2019	1,119	197	7,736	341	139
2020	1,117	206	8,289	174	139
2021	1,131	206	8,297	151	288
2022	1,131	218	7,980	354	288
2023	1,131	224	6,981	828	288
2024	1,131	234	7,691	384	289
2025	1,538	0	9,144	185	288
2026	1,538	0	9,449	140	288
2027	1,538	0	9,179	299	288
2028	1,538	0	9,458	167	289
2029	1,538	0	9,254	202	288
2030	1,538	0	8,992	515	288

d. Below is the projected mix of capacity and generation by source for Option #2 (Replace Big Sandy 2 with a [Brownfield] CC build) under the FT-CSAPR 'Base' commodity pricing scenario.

Option 2 FT-CASPR 'Base' Fleet	KPCo Installed Capacity MW	PJM Market Firm Capacity Purchases MW	KPCo Total Thermal Generation GWh	PJM Market Purchases GWh	KPCo Contract Purchases GWh
2011	1,115	0	8,280	369	58
2012	1,316	0	9,438	80	138
2013	1,317	0	7,657	807	138
2014	1,387	0	7,961	690	139
2015	1,108	225	8,234	260	139
2016	1,277	34	7,136	575	139
2017	1,276	18	6,935	716	139
2018	1,278	26	7,146	580	139
2019	1,286	30	6,928	789	139
2020	1,288	34	7,248	571	139
2021	1,303	35	7,237	529	288
2022	1,303	47	7,279	519	288
2023	1,303	53	6,929	797	288
2024	1,303	63	7,032	752	289
2025	1,710	0	8,615	421	288
2026	1,710	0	8,734	333	288
2027	1,710	0	8,786	387	288
2028	1,710	0	8,736	378	289
2029	1,710	0	8,633	407	288
2030	1,710	0	8,807	402	288

e. Below is the projected mix of capacity and generation by source for Option #3 (Replace Big Sandy 2 with a "CC-Repowered Big Sandy Unit 1") under the FT-CSAPR 'Base' commodity pricing scenario.

Option 3 FT-CASPR 'Base' Fleet	KPCo Installed Capacity MW	PJM Market Firm Capacity Purchases MW	KPCo Total Thermal Generation GWh	PJM Market Purchases GWh	KPCo Contract Purchases GWh
2011	1,115	0	8,280	369	58
2012	1,316	0	9,438	80	138
2013	1,317	0	7,657	807	138
2014	1,387	0	7,961	690	139
2015	1,364	0	9,090	139	139
2016	1,153	158	7,049	621	139
2017	1,152	142	6,854	766	139
2018	1,154	150	7,069	622	139
2019	1,162	154	6,848	843	139
2020	1,164	158	7,169	612	139
2021	1,179	159	7,154	569	288
2022	1,179	171	7,201	559	288
2023	1,179	177	6,844	855	288
2024	1,179	187	6,948	807	289
2025	1,586	0	8,557	421	288
2026	1,586	0	8,654	346	288
2027	1,586	0	8,720	390	288
2028	1,586	0	8,661	390	289
2029	1,586	0	8,553	424	288
2030	1,586	0	8,735	409	288

f. See attached file.

g. At this point it would be purely speculative as to when additional capacity would be required should Big Sandy Unit 2 be retrofitted and not retired. That said, based on the incremental re-investment in that unit, it would be desired that the unit could continue operation through the full 'study period' utilized in the unit disposition evaluation set forth in Mr. Weaver's direct testimony (i.e., through 2040). Hence replacement capacity for Big Sandy 2 may not be required until that point. However, any *incremental* KPCo load & demand growth could require such additional capacity to be acquired/built slightly sooner.

h. As is recognized in either Option #2 or Option #3 as identified in TABLE 1 of Mr. Weaver's testimony, replacement capacity would be required immediately upon the retirement of Big Sandy Unit 2.

i. See the response to part g. of this question.

j. See the response to part h. of this question.

WITNESS: Scott C Weaver

Case No. 2011-00401
Sierra Club 53
53 Direct Testimony of Weaver, page 11 and 12, page 53 and Exhibit SCW-1 pages 3 to 6.
f. Please provide the Company's projected energy and peak load requirement, broken down by sector, through 2030.

Peak Demand (MW)

	Residential	Commercial	Industrial	Other Retail	Wholesale	Internal Peak	DSM	Internal Peak Before DSM	PJM Diversity	Diversified Peak
2011	543	297	391	2	19	1,251	2	1,253	32	1,221
2012	555	297	392	2	20	1,266	5	1,270	32	1,238
2013	549	298	396	2	20	1,264	8	1,272	33	1,239
2014	546	298	400	2	20	1,266	10	1,276	33	1,243
2015	544	299	403	2	20	1,268	12	1,280	33	1,247
2016	543	297	406	2	20	1,268	17	1,285	33	1,252
2017	523	300	423	2	20	1,269	20	1,289	33	1,256
2018	531	302	427	2	20	1,282	22	1,304	33	1,271
2019	535	303	431	2	20	1,291	24	1,315	34	1,281
2020	552	300	421	2	20	1,295	26	1,321	34	1,287
2021	555	302	427	2	21	1,307	26	1,333	34	1,299
2022	558	305	431	2	21	1,316	27	1,343	34	1,309
2023	541	309	447	2	21	1,321	26	1,347	34	1,313
2024	544	311	450	2	21	1,328	26	1,355	35	1,320
2025	550	314	455	2	21	1,342	26	1,368	35	1,333
2026	554	317	459	2	21	1,353	26	1,379	35	1,344
2027	576	315	450	2	21	1,363	27	1,390	36	1,354
2028	580	316	452	2	21	1,371	27	1,397	36	1,362
2029	564	321	470	2	21	1,379	26	1,405	36	1,369
2030	569	323	474	2	21	1,389	26	1,415	36	1,379
Compound Growth Rates:										
2011-2020	0.18%	0.12%	0.84%	0.03%	0.52%	0.38%	32.83%	0.59%	0.59%	0.59%
2011-2030	0.25%	0.46%	1.02%	0.19%	0.39%	0.55%	14.47%	0.64%	0.64%	0.64%

GWh Load* **

	Residential	Commercial	Industrial	Other Retail	Wholesale	Internal Load	DSM	Internal Load Before DSM
2011	2,643	1,543	3,356	11	101	7,654	12	7,666
2012	2,662	1,545	3,378	11	103	7,699	30	7,729
2013	2,620	1,544	3,400	11	103	7,679	49	7,728
2014	2,596	1,546	3,435	11	104	7,692	63	7,755
2015	2,577	1,547	3,463	11	104	7,702	74	7,776
2016	2,558	1,541	3,496	11	104	7,711	101	7,812
2017	2,542	1,541	3,529	11	105	7,729	119	7,848
2018	2,535	1,546	3,563	11	105	7,761	129	7,890
2019	2,532	1,552	3,595	11	106	7,796	137	7,934
2020	2,526	1,558	3,629	11	106	7,831	144	7,976
2021	2,526	1,568	3,664	11	106	7,876	146	8,021
2022	2,529	1,578	3,699	12	107	7,924	146	8,071
2023	2,534	1,589	3,733	12	107	7,975	146	8,122
2024	2,543	1,601	3,767	12	108	8,031	146	8,177
2025	2,549	1,613	3,799	12	108	8,081	145	8,225
2026	2,557	1,625	3,830	12	108	8,132	144	8,276
2027	2,567	1,636	3,862	12	108	8,184	144	8,328
2028	2,579	1,646	3,893	12	109	8,237	144	8,382
2029	2,587	1,655	3,922	12	109	8,284	144	8,429
2030	2,597	1,665	3,951	12	109	8,334	144	8,479
Compound Growth Rates:								
2011-2020	-0.50%	0.11%	0.88%	0.11%	0.56%	0.25%	31.67%	0.44%
2011-2030	-0.09%	0.40%	0.86%	0.14%	0.42%	0.45%	13.93%	0.53%

*Includes losses.
** Annual GWh differences result from a revised Cumulative Energy Efficiency estimate

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 6, lines 12 to 20 and Exhibit SCW-1.

a. Please provide all assumptions and workpapers underlying the assumed variable correlations found in Table 1-4 on page 11 of SCW-1.

b. Please explain why natural gas prices are assumed to have a negative correlation with a CO2 Emission Price/Tax, whereas coal prices have a positive correlation with a CO2 Emission Price/Tax.

c. Please explain why power prices are assumed to have a negative correlation with a CO2 Emission Price/Tax.

RESPONSE

a. See Page 2 of this response.

b. The correlations were calculated using futures prices from the Intercontinental Exchange (ICE futures exchange). The United States does not have an exchange where carbon futures are actively traded along side other commodities; it is believed that the commodities would trade in a similar manner as they do in the European system. The specific contracts were the ECX EUA (European Union allowances)and UK Natural Gas futures, and the ECX EUA and Newcastle Coal futures.

   A possible explanation for the observed market pricing is that in an environment where more coal is being consumed, increasing its cost (and decreasing the demand and price for the alternative [natural gas], more allowances must also be consumed, increasing their cost.

c. The correlations were calculated using futures prices from the ICE futures exchange. The specific contracts were the ECX EUA and UK Base Electricity futures.

A possible explanation for the market pricing is that in an environment where power prices are low, more coal will be consumed increasing the need for additional allowances.

WITNESS: Scott C Weaver

Daily Volumes for ICE UK Natural Gas Futures (Monthly)
3-Mar-11

Month	Open	High	Low	Sett	Chg	Vol	EFP	EFS	Block	Open Int	Prev Day Vol (02-Mar-2011)
Apr11	55.8	56.5	55.6	55.89	0.01	4,730	50	0	0	22,125	5,245
May11	55.75	56.35	55.55	55.79	-0.2	625	0	0	0	11,860	800
Jun11	55.87	56	55.72	56	0	270	20	0	0	9,070	80
Jul11				55.81	-0.08	0	0	0	0	9,090	0
Aug11				56.5	0.1	0	0	0	0	9,080	0
Sep11	56.35	56.7	55.75	56.14	-0.1	590	0	0	0	9,525	0
Oct11				60.4	-0.2	0	0	0	0	9,365	150
Nov11				64.12	0.05	0	0	0	0	10,920	0
Dec11				67.3	-0.15	0	0	0	0	9,445	250
Jan12				68.8	-0.12	0	0	0	0	9,120	0
Feb12				67.85	-0.2	0	0	0	0	9,145	0
Mar12				66.48	-0.07	0	0	0	0	9,495	100
Apr12				61.79	-0.4	0	0	0	0	4,380	0
May12				60.46	-0.31	0	0	0	0	4,355	0
Jun12				59.58	-0.32	0	0	0	0	4,355	0
Jul12				59.6	-0.31	0	0	0	0	4,245	0
Aug12				60.39	-0.29	0	0	0	0	4,245	0
Sep12				60.25	-0.29	0	0	0	0	4,245	0
Oct12				65.14	-0.21	0	0	0	0	4,880	0
Nov12				65.14	-0.21	0	0	0	0	4,880	0
Dec12				65.01	-0.21	0	0	0	0	4,880	0
Jan13				68.47	-0.17	0	0	0	0	4,680	0
Feb13				68.47	-0.17	0	0	0	0	4,680	0
Mar13				68.56	-0.17	0	0	0	0	4,680	0
Apr13				62.08	-0.18	0	0	0	0	3,610	0
May13				62.08	-0.18	0	0	0	0	3,610	0
Jun13				62.08	-0.18	0	0	0	0	3,610	0
Jul13				61.61	-0.22	0	0	0	0	3,610	0
Aug13				61.61	-0.22	0	0	0	0	3,610	0
Sep13				61.61	-0.22	0	0	0	0	3,610	0
Oct13				66.28	-0.15	0	0	0	0	3,640	0
Nov13				66.28	-0.15	0	0	0	0	3,640	0
Dec13				66.28	-0.15	0	0	0	0	3,640	0
Jan14				70.22	-0.15	0	0	0	0	3,780	0
Feb14				70.22	-0.15	0	0	0	0	3,780	0
Mar14				70.22	-0.15	0	0	0	0	3,780	0
Apr14				63.5	-0.4	0	0	0	0	815	0
May14				63.5	-0.4	0	0	0	0	815	0
Jun14				63.5	-0.4	0	0	0	0	815	0
Jul14				63.5	-0.4	0	0	0	0	815	0
Aug14				63.5	-0.4	0	0	0	0	815	0
Sep14				63.5	-0.4	0	0	0	0	815	0
Oct14				70.47	0.05	0	0	0	0	730	0
Nov14				70.47	0.05	0	0	0	0	730	0
Dec14				70.47	0.05	0	0	0	0	730	0
Jan15				70.59	0.05	0	0	0	0	730	0
Feb15				70.59	0.05	0	0	0	0	730	0
Mar15				70.59	0.05	0	0	0	0	730	0
Apr15				65.98	-0.21	0	0	0	0	320	0
May15				65.98	-0.21	0	0	0	0	320	0
Jun15				65.98	-0.21	0	0	0	0	320	0
Jul15				65.98	-0.21	0	0	0	0	320	0

Aug15	65.98	-0.21	0	0	0	0	320	0
Sep15	65.98	-0.21	0	0	0	0	320	0
Oct15	72.47	-0.01	0	0	0	0	230	0
Nov15	72.47	-0.01	0	0	0	0	230	0
Dec15	72.47	-0.01	0	0	0	0	230	0
Jan16	72.44	-0.01	0	0	0	0	230	0
Feb16	72.44	-0.01	0	0	0	0	230	0
Mar16	72.44	-0.01	0	0	0	0	230	0
Apr16	67.87	-0.12	0	0	0	0	0	0
May16	67.87	-0.12	0	0	0	0	0	0
Jun16	67.87	-0.12	0	0	0	0	0	0
Jul16	67.87	-0.12	0	0	0	0	0	0
Aug16	67.87	-0.12	0	0	0	0	0	0
Sep16	67.87	-0.12	0	0	0	0	0	0
Oct16	75.09	0.09	0	0	0	0	0	0
Nov16	75.09	0.09	0	0	0	0	0	0
Dec16	75.09	0.09	0	0	0	0	0	0
Jan17	75.09	0.09	0	0	0	0	0	0
Feb17	75.09	0.09	0	0	0	0	0	0
Mar17	75.09	0.09	0	0	0	0	0	0
Apr17	69.67	-0.12	0	0	0	0	0	0
May17	69.67	-0.12	0	0	0	0	0	0
Jun17	69.67	-0.12	0	0	0	0	0	0
Jul17	69.67	-0.12	0	0	0	0	0	0
Aug17	69.67	-0.12	0	0	0	0	0	0
Sep17	69.67	-0.12	0	0	0	0	0	0
Total:			**6,215**	**70**	**0**	**0**	**239,235**	**6,625**

* Open Interest is recorded against the monthly strip, inclusive, where possible, of monthly, quarterly, seasonal or calendar strips. Volume and Price data will be recorded against the traded strip.

Daily Volumes for ICE UK Base Electricity Futures (Monthly)
3-Mar-11

Month	Open	High	Low	Sett	Chg	Vol	EFP	EFS	Block	Open Int	Prev Day Vol (02-Mar-2011)
Apr-11				48.7	0.2	0	0	0	0	420	0
May-11				48.79	0.13	0	0	0	0	420	0
Jun-11				49.12	0.14	0	0	0	0	420	0
Jul-11				49.01	-0.04	0	0	0	0	420	0
Aug-11				48.96	-0.09	0	0	0	0	420	0
Sep-11				49.52	0	0	0	0	0	420	0
Oct-11				53.85	-0.06	0	0	0	0	720	0
Nov-11				53.85	-0.06	0	0	0	0	720	0
Dec-11				53.85	-0.06	0	0	0	0	720	0
Jan-12				55.72	0.01	0	0	0	0	720	0
Feb-12				55.72	0.01	0	0	0	0	720	0
Mar-12				55.72	0.01	0	0	0	0	720	0
Apr-12				51.32	-0.21	0	0	0	0	180	0
May-12				51.32	-0.21	0	0	0	0	180	0
Jun-12				51.32	-0.21	0	0	0	0	180	0
Jul-12				51.32	-0.21	0	0	0	0	180	0
Aug-12				51.32	-0.21	0	0	0	0	180	0
Sep-12				51.32	-0.21	0	0	0	0	180	0
Oct-12				55.48	-0.13	0	0	0	0	270	0
Nov-12				55.48	-0.13	0	0	0	0	270	0
Dec-12				55.48	-0.13	0	0	0	0	270	0
Jan-13				55.48	-0.13	0	0	0	0	270	0
Feb-13				55.48	-0.13	0	0	0	0	270	0
Mar-13				55.48	-0.13	0	0	0	0	270	0
Apr-13				52.43	-0.25	0	0	0	0	90	0
May-13				52.43	-0.25	0	0	0	0	90	0
Jun-13				52.43	-0.25	0	0	0	0	90	0
Jul-13				52.43	-0.25	0	0	0	0	90	0
Aug-13				52.43	-0.25	0	0	0	0	90	0
Sep-13				52.43	-0.25	0	0	0	0	90	0
Oct-13				57	-0.22	0	0	0	0	115	0
Nov-13				57	-0.22	0	0	0	0	115	0
Dec-13				57	-0.22	0	0	0	0	115	0
Jan-14				57	-0.22	0	0	0	0	115	0
Feb-14				57	-0.22	0	0	0	0	115	0
Mar-14				57	-0.22	0	0	0	0	115	0
Apr-14				55.73	-0.25	0	0	0	0	240	0
May-14				55.73	-0.25	0	0	0	0	240	0
Jun-14				55.73	-0.25	0	0	0	0	240	0
Jul-14				55.73	-0.25	0	0	0	0	240	0
Aug-14				55.73	-0.25	0	0	0	0	240	0
Sep-14				55.73	-0.25	0	0	0	0	240	0
Oct-14				60.52	-0.29	0	0	0	0	30	0
Nov-14				60.52	-0.29	0	0	0	0	30	0
Dec-14				60.52	-0.29	0	0	0	0	30	0
Jan-15				60.52	-0.29	0	0	0	0	30	0
Feb-15				60.52	-0.29	0	0	0	0	30	0
Mar-15				60.52	-0.29	0	0	0	0	30	0
Apr-15				59.61	-0.25	0	0	0	0	0	0
May-15				59.61	-0.25	0	0	0	0	0	0

Jun-15	59.61	-0.25	0	0	0	0	0	0
Jul-15	59.61	-0.25	0	0	0	0	0	0
Aug-15	59.61	-0.25	0	0	0	0	0	0
Sep-15	59.61	-0.25	0	0	0	0	0	0
Total:			**0**	**0**	**0**	**0**	**12,390**	**0**

* Open Interest is recorded against the monthly strip, inclusive, where possible, of monthly, quarterly, seasonal or calendar strips. Volume and Price data will be recorded against the traded strip.

Daily Volumes for ICE ECX EUA Futures (Monthly)
3-Mar-11

Month	Open	High	Low	Sett	Chg	Vol	EFP	EFS	Block	Open Int*	Prev Day Vol (02-Mar-2011)
Mar11	15.25	15.25	15.1	15.17	-0.03	16	0	0	0	2,920	50
Jun11				15.25	-0.1	0	0	0	0	105	0
Sep11				15.36	-0.14	0	0	0	0	105	0
Dec11	15.57	15.63	15.41	15.45	-0.18	13,983	2,643	0	0	121,902	9,047
Mar12				15.61	-0.17	0	0	0	0	286	0
Jun12				15.77	-0.16	0	0	0	0	75	0
Sep12				15.93	-0.15	0	0	0	0	75	0
Dec12	16.19	16.23	16.07	16.08	-0.14	9,218	1,725	0	0	233,852	4,665
Mar13				16.38	-0.13	300	300	0	0	3,250	950
Jun13				17.07	-0.1	0	0	0	0	0	0
Dec13	17.38	17.4	17.26	17.28	-0.1	2,423	475	0	0	50,961	626
Dec14	18.3	18.3	18.24	18.18	-0.05	125	0	0	0	5,117	177
Dec15				19.08	-0.05	0	0	0	0	300	0
Dec16				19.98	-0.05	0	0	0	0	300	0
Dec17				20.88	-0.05	0	0	0	0	300	0
Dec18				21.78	-0.05	0	0	0	0	300	0
Dec19				22.7	-0.05	0	0	0	0	20	0
Dec20				23.65	-0.05	0	0	0	0	10	0
Total:						**26,065**	**5,143**	**0**	**0**	**419,878**	**15,515**

* Open Interest is recorded against the monthly strip, inclusive, where possible, of monthly, quarterly, seasonal or calendar strips. Volume and Price data will be recorded against the traded strip.

Daily Volumes for gC Newcastle Coal Futures (Monthly)
3-Mar-11

Month	Open	High	Low	Sett	Chg	Vol	EFP	EFS	Block	Open Int	Prev Day Vol (03/02/2011)
Mar11				130.4	-0.2	0	0	0	0	1,443	0
Apr11				128.8	0.15	0	0	0	0	1,395	0
May11				127.45	0.4	0	0	0	0	1,370	0
Jun11				126.45	0.25	0	0	0	0	1,345	0
Jul11				125.6	0.15	0	0	0	0	939	0
Aug11				125.6	0.15	0	0	0	0	939	0
Sep11				125.6	0.15	0	0	0	0	939	0
Oct11				125.1	0.05	0	0	0	0	900	0
Nov11				125.1	0.05	0	0	0	0	900	0
Dec11				125.1	0.05	0	0	0	0	900	0
Jan12				124.2	0.5	0	0	0	0	605	0
Feb12				124.2	0.5	0	0	0	0	605	0
Mar12				124.2	0.5	0	0	0	0	605	0
Apr12				123.5	0.35	0	0	0	0	510	0
May12				123.5	0.35	0	0	0	0	510	0
Jun12				123.5	0.35	0	0	0	0	510	0
Jul12				123.1	0.1	0	0	0	0	495	0
Aug12				123.1	0.1	0	0	0	0	495	0
Sep12				123.1	0.1	0	0	0	0	495	0
Oct12				122.7	-0.1	0	0	0	0	495	0
Nov12				122.7	-0.1	0	0	0	0	495	0
Dec12				122.7	-0.1	0	0	0	0	495	0
Jan13				122.15	0.3	0	0	0	0	205	0
Feb13				122.15	0.3	0	0	0	0	205	0
Mar13				122.15	0.3	0	0	0	0	205	0
Apr13				122.2	0.3	0	0	0	0	205	0
May13				122.2	0.3	0	0	0	0	205	0
Jun13				122.2	0.3	0	0	0	0	205	0
Jul13				122.2	0.3	0	0	0	0	205	0
Aug13				122.2	0.3	0	0	0	0	205	0
Sep13				122.2	0.3	0	0	0	0	205	0
Oct13				122.2	0.3	0	0	0	0	205	0
Nov13				122.2	0.3	0	0	0	0	205	0
Dec13				122.2	0.3	0	0	0	0	205	0
Jan14				122.2	0.3	0	0	0	0	140	0
Feb14				122.2	0.3	0	0	0	0	140	0
Mar14				122.2	0.3	0	0	0	0	140	0
Apr14				122.2	0.3	0	0	0	0	140	0
May14				122.2	0.3	0	0	0	0	140	0
Jun14				122.2	0.3	0	0	0	0	140	0
Jul14				122.2	0.3	0	0	0	0	140	0
Aug14				122.2	0.3	0	0	0	0	140	0
Sep14				122.2	0.3	0	0	0	0	140	0
Oct14				122.2	0.3	0	0	0	0	140	0
Nov14				122.2	0.3	0	0	0	0	140	0
Dec14				122.2	0.3	0	0	0	0	140	0
Jan15				122.85	0.45	0	0	0	0	0	0
Feb15				122.85	0.45	0	0	0	0	0	0
Mar15				122.85	0.45	0	0	0	0	0	0
Apr15				122.85	0.45	0	0	0	0	0	0

May15	122.85	0.45	0	0	0	0	0	0
Jun15	122.85	0.45	0	0	0	0	0	0
Jul15	122.85	0.45	0	0	0	0	0	0
Aug15	122.85	0.45	0	0	0	0	0	0
Sep15	122.85	0.45	0	0	0	0	0	0
Oct15	122.85	0.45	0	0	0	0	0	0
Nov15	122.85	0.45	0	0	0	0	0	0
Dec15	122.85	0.45	0	0	0	0	0	0
Jan16	123.4	0.4	0	0	0	0	0	0
Feb16	123.4	0.4	0	0	0	0	0	0
Mar16	123.4	0.4	0	0	0	0	0	0
Apr16	123.4	0.4	0	0	0	0	0	0
May16	123.4	0.4	0	0	0	0	0	0
Jun16	123.4	0.4	0	0	0	0	0	0
Jul16	123.4	0.4	0	0	0	0	0	0
Aug16	123.4	0.4	0	0	0	0	0	0
Sep16	123.4	0.4	0	0	0	0	0	0
Oct16	123.4	0.4	0	0	0	0	0	0
Nov16	123.4	0.4	0	0	0	0	0	0
Dec16	123.4	0.4	0	0	0	0	0	0
Total:			**0**	**0**	**0**	**0**	**21,525**	**0**

* Open Interest is recorded against the monthly strip, inclusive, where possible, of monthly, quarterly, seasonal or calendar strips. Volume and Price data will be recorded against the traded strip.

Table 7.8 Coal Prices, 1949-2009

(Dollars per Short Ton)

Year	Bituminous Coal		Subbituminous Coal		Lignite [1]		Anthracite		Total	
	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]	Nominal [2]	Real [3]
1949	4.9 [4]	33.83 [4,R]	[4]	[4]	2.37	16.36 [R]	8.9	61.44 [R]	5.24	36.17 [R]
1950	4.86 [4]	33.19 [4,R]	[4]	[4]	2.41	16.46 [R]	9.34	63.78 [R]	5.19	35.44 [R]
1951	4.94 [4]	31.47 [4,R]	[4]	[4]	2.44	15.54 [R]	9.94	63.32 [R]	5.29	33.7 [R]
1952	4.92 [4]	30.81 [4,R]	[4]	[4]	2.39	14.97 [R]	9.58	59.99 [R]	5.27	33 [R]
1953	4.94 [4]	30.57 [4,R]	[4]	[4]	2.38	14.73 [R]	9.87	61.07 [R]	5.23	32.36 [R]
1954	4.54 [4]	27.84 [4,R]	[4]	[4]	2.43	14.9 [R]	8.76	53.72 [R]	4.81	29.49 [R]
1955	4.51 [4]	27.19 [4,R]	[4]	[4]	2.38	14.35 [R]	8	48.23 [R]	4.69	28.28 [R]
1956	4.83 [4]	28.15 [4,R]	[4]	[4]	2.39	13.93 [R]	8.33	48.55 [R]	5.01	29.2 [R]
1957	5.09 [4]	28.71 [4,R]	[4]	[4]	2.35	13.26 [R]	9.11	51.39 [R]	5.28	29.79 [R]
1958	4.87 [4]	26.87 [4,R]	[4]	[4]	2.35	12.97 [R]	9.14	50.43 [R]	5.07	27.97 [R]
1959	4.79 [4]	26.12 [4,R]	[4]	[4]	2.25	12.27 [R]	8.55	46.62 [R]	4.95	26.99 [R]
1960	4.71 [4]	25.33 [4,R]	[4]	[4]	2.29	12.31 [R]	8.01	43.07 [R]	4.83	25.97 [R]
1961	4.6 [4]	24.46 [4,R]	[4]	[4]	2.24	11.91 [R]	8.26	43.92 [R]	4.73	25.15 [R]
1962	4.5 [4]	23.61 [4,R]	[4]	[4]	2.23	11.7 [R]	7.99	41.92 [R]	4.62	24.24 [R]
1963	4.4 [4]	22.84 [4,R]	[4]	[4]	2.17	11.26 [R]	8.64	44.85 [R]	4.55	23.62 [R]
1964	4.46 [4]	22.8 [4,R]	[4]	[4]	2.14	10.94 [R]	8.93	45.65 [R]	4.6	23.51 [R]
1965	4.45 [4]	22.34 [4,R]	[4]	[4]	2.13	10.69 [R]	8.51	42.72 [R]	4.55	22.84 [R]
1966	4.56 [4]	22.26 [4,R]	[4]	[4]	1.98	9.67 [R]	8.08	39.45 [R]	4.62	22.55 [R]
1967	4.64 [4]	21.97 [4,R]	[4]	[4]	1.92	9.09 [R]	8.15	38.6 [R]	4.69	22.21 [R]
1968	4.7 [4]	21.35 [4,R]	[4]	[4]	1.79	8.13 [R]	8.78	39.89 [R]	4.75	21.58 [R]
1969	5.02 [4]	21.73 [4,R]	[4]	[4]	1.86	8.05 [R]	9.91	42.9 [R]	5.08	21.99 [R]
1970	6.3 [4]	25.91 [4,R]	[4]	[4]	1.86	7.65 [R]	11.03	45.36 [R]	6.34	26.07 [R]
1971	7.13 [4]	27.92 [4,R]	[4]	[4]	1.93	7.56 [R]	12.08	47.31 [R]	7.15	28 [R]
1972	7.78 [4]	29.21 [4,R]	[4]	[4]	2.04	7.66 [R]	12.4	46.56 [R]	7.72	28.99 [R]
1973	8.71 [4]	30.98 [4,R]	[4]	[4]	2.09	7.43 [R]	13.65	48.56 [R]	8.59	30.56 [R]
1974	16.01 [4]	52.21 [4,R]	[4]	[4]	2.19	7.14 [R]	22.19	72.36 [R]	15.82	51.59 [R]
1975	19.79 [4]	58.96 [4,R]	[4]	[4]	3.17	9.44 [R]	32.26	96.12 [R]	19.35	57.65 [R]
1976	20.11 [4]	56.67 [4,R]	[4]	[4]	3.74	10.54 [R]	33.92	95.58 [R]	19.56	55.12 [R]
1977	20.59 [4]	54.54 [4,R]	[4]	[4]	4.03	10.68 [R]	34.86	92.34 [R]	19.95	52.85 [R]
1978	22.64 [4]	58.04 [4,R]	[4]	[4]	5.68	14.06 [R]	35.25	87.25 [R]	21.86	54.11 [R]
1979	27.31	62.41 [R]	9.55	21.82 [R]	6.48	14.81 [R]	41.06	93.83 [R]	23.75	54.27 [R]
1980	29.17	61.09 [R]	11.08	23.2 [R]	7.6	15.92 [R]	42.51	89.02 [R]	24.65	51.62 [R]
1981	31.51	60.34 [R]	12.18	23.32 [R]	8.85	16.95 [R]	44.28	84.79 [R]	26.4	50.55 [R]
1982	32.15	58.02 [R]	13.37	24.13 [R]	9.79	17.67 [R]	49.85	89.96 [R]	27.25	49.18 [R]
1983	31.11	54.01 [R]	13.03	22.62 [R]	9.91	17.2 [R]	52.29	90.78 [R]	25.98	45.1 [R]
1984	30.63	51.25 [R]	12.41	20.76 [R]	10.45	17.48 [R]	48.22	80.68 [R]	25.61	42.85 [R]
1985	30.78	49.99 [R]	12.57	20.41 [R]	10.68	17.34 [R]	45.8	74.38 [R]	25.2	40.93 [R]
1986	28.84	45.82 [R]	12.26	19.48 [R]	10.64	16.91 [R]	44.12	70.1 [R]	23.79	37.8 [R]
1987	28.19	43.53 [R]	11.32	17.48 [R]	10.85	16.75 [R]	43.65	67.4 [R]	23.07	35.62 [R]

1988	27.66		41.29	[R]	10.45		15.6	[R]	10.06		15.02	[R]	44.16		65.92	[R]	22.07		32.95	[R]
1989	27.4		39.41	[R]	10.16		14.61	[R]	9.91		14.26	[R]	42.93		61.75	[R]	21.82		31.39	[R]
1990	27.43		37.99	[R]	9.7		13.43	[R]	10.13		14.03	[R]	39.4		54.57	[R]	21.76		30.14	[R]
1991	27.49		36.77	[R]	9.68		12.95	[R]	10.89		14.57	[R]	36.34		48.61	[R]	21.49		28.75	[R]
1992	26.78		34.99	[R]	9.68		12.65	[R]	10.81		14.12	[R]	34.24		44.74	[R]	21.03		27.48	[R]
1993	26.15		33.43	[R]	9.33		11.93	[R]	11.11		14.2	[R]	32.94		42.11	[R]	19.85		25.38	[R]
1994	25.68		32.15	[R]	8.37		10.46	[R]	10.77		13.48	[R]	36.07		45.16	[R]	19.41		24.3	[R]
1995	25.56		31.35	[R]	8.1		9.93	[R]	10.83		13.28	[R]	39.78		48.78	[R]	18.83		23.09	[R]
1996	25.17		30.29	[R]	7.87		9.47	[R]	10.92		13.14	[R]	36.78		44.27	[R]	18.5		22.27	[R]
1997	24.64		29.14	[R]	7.42		8.78	[R]	10.91		12.9	[R]	35.12		41.54	[R]	18.14		21.45	[R]
1998	24.87		29.08	[R]	6.96		8.14	[R]	11.08		12.96	[R]	42.91		50.18	[R]	17.67		20.66	[R]
1999	23.92		27.57	[R]	6.87		7.92	[R]	11.04		12.72	[R]	35.13		40.49	[R]	16.63		19.17	[R]
2000	24.15		27.24	[R]	7.12		8.03	[R]	11.41		12.87	[R]	40.9		46.14	[R]	16.78		18.93	[R]
2001	25.36		27.98	[R]	6.67		7.36	[R]	11.52		12.71	[R]	47.67		52.59	[R]	17.38		19.17	[R]
2002	26.57		28.84	[R]	7.34		7.97	[R]	11.07		12.02	[R]	47.76		51.87	[R]	17.98		19.52	[R]
2003	26.73		28.41	[R]	7.73		8.21	[R]	11.2		11.9	[R]	49.87		53	[R]	17.85		18.97	[R]
2004	30.56		31.58	[R]	8.12		8.39	[R]	12.27		12.68	[R]	39.77		41.1	[R]	19.93		20.6	[R]
2005	36.8		36.8	[R]	8.68		8.68	[R]	13.49		13.49	[R]	41		41	[R]	23.59		23.59	[R]
2006	39.32		38.08	[R]	9.95		9.64	[R]	14		13.56	[R]	43.61		42.23	[R]	25.16		24.37	[R]
2007	40.8		38.41	[R]	10.69		10.06	[R]	14.89		14.02	[R]	52.24		49.18	[R]	26.2		24.67	[R]
2008	51.39	[R]	47.37	[R]	12.31	[R]	11.35	[R]	16.5	[R]	15.21	[R]	60.76	[R]	56.01	[R]	31.25	[R]	28.81	[R]
2009[E]	54.25		49.42		13.71		12.49		21.53		19.61		60.35		54.98		32.92		29.99	

[1]Because of withholding to protect company confidentiality, lignite prices exclude Texas for 1955-1977 and Montana for 1974-1976. As a result, lignite prices for 1974-1977 are for North Dakota only.

[2]See "Nominal Dollars" in Glossary.

[3]In chained (2005) dollars, calculated by using gross domestic product implicit price deflators in Table D1. See "Chained Dollars" in Glossary.

[4]Through 1978, subbituminous coal is included in "Bituminous Coal."

R=Revised. E=Estimate.

Note: Prices are free-on-board (F.O.B.) rail/barge prices, which are the F.O.B. prices of coal at the point of first sale, excluding freight or shipping and insurance costs. For 1949-2000, prices are for open market and captive coal sales; for 2001-2007, prices are for open market coal sales; for 2008 forward, prices are for open market and captive coal sales. See "Captive Coal," "Free on Board (F.O.B.)," and "Open Market Coal" in Glossary.

Web Page: For related information, see http://www.eia.gov/fuelcoal.html.

Sources: • 1949-1975 Bureau of Mines (BOM), *Minerals Yearbook*. • 1976 U.S. Energy Information Administration (EIA), Energy Data Report, *Coal Bituminous and Lignite in 1976*, and BOM, *Minerals Yearbook*. • 1977 and 1978 EIA, Energy Data Reports, *Bituminous Coal and Lignite Production and Mine Operations*, and *Coal Pennsylvania Anthracite*. • 1979 EIA, *Coal Production*, and Energy Data Report, *Coal Pennsylvania Anthracite*. • 1980-1992 EIA, *Coal Production*, annual reports. • 1993-2000 EIA, *Coal Industry Annual*, annual reports and unpublished revisions. • 2001-2008 EIA, *Annual Coal Report*, annual reports. • 2009 EIA, Form EIA-7A, "Coal Production Report," and U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report."

Table 7.3 Coal Consumption by Sector, 1949-2009

(Million Short Tons)

Year	Residential Sector [1]	Commercial Sector [1] CHP [3]	Commercial Sector [1] Other [4]	Commercial Sector [1] Total	Industrial Sector Coke Plants	Industrial Sector Other Industrial CHP [3]	Industrial Sector Other Industrial Non-CHP [5]	Industrial Sector Other Industrial Total	Industrial Sector Total	Transportation Sector	Electric Power Sector [2] Electricity Only	Electric Power Sector [2] CHP	Electric Power Sector [2] Total	Total	
1949	52.4	[7]	64.1	64.1	91.4	[8]	121.2	121.2	212.6	70.2	84	NA	84	483.2	
1950	51.6	[7]	63	63	104	[8]	120.6	120.6	224.6	63	91.9	NA	91.9	494.1	0.09405
1951	47.7	[7]	53.8	53.8	113.7	[8]	128.7	128.7	242.4	56.2	105.8	NA	105.8	505.9	0.15125
1952	44.3	[7]	48	48	97.8	[8]	117.1	117.1	214.9	39.8	107.1	NA	107.1	454.1	0.01229
1953	39.6	[7]	39.6	39.6	113.1	[8]	117	117	230.1	29.6	115.9	NA	115.9	454.8	0.08217
1954	35.2	[7]	33.8	33.8	85.6	[8]	98.2	98.2	183.9	18.6	118.4	NA	118.4	389.9	0.02157
1955	35.6	[7]	32.9	32.9	107.7	[8]	110.1	110.1	217.8	17	143.8	NA	143.8	447	0.21453
1956	34.7	[7]	29.5	29.5	106.3	[8]	114.3	114.3	220.6	13.8	158.3	NA	158.3	456.9	0.10083
1957	27	[7]	22.1	22.1	108.4	[8]	106.5	106.5	214.9	9.8	160.8	NA	160.8	434.5	0.01579
1958	27.3	[7]	20.6	20.6	76.8	[8]	100.5	100.5	177.4	4.7	155.7	NA	155.7	385.7	-0.03172
1959	23.7	[7]	17.1	17.1	79.6	[8]	92.7	92.7	172.3	3.6	168.4	NA	168.4	385.1	0.08157
1960	24.2	[7]	16.8	16.6	81.4	[8]	96	96	177.4	3	176.7	NA	176.7	398.1	0.04929
1961	22	[7]	15.3	15.3	74.2	[8]	95.9	95.9	170.1	0.8	182.2	NA	182.2	390.4	0.03113
1962	21.5	[7]	15	15	74.7	[8]	97.1	97.1	171.7	0.7	193.3	NA	193.3	402.3	0.06092
1963	18.2	[7]	13.2	13.2	78.1	[8]	101.9	101.9	180	0.7	211.3	NA	211.3	423.5	0.09312
1964	15.8	[7]	11.4	11.4	89.2	[8]	103.1	103.1	192.4	0.7	225.4	NA	225.4	445.7	0.06673
1965	14.6	[7]	11	11	95.3	[8]	105.6	105.6	200.8	0.7	244.8	NA	244.8	472	0.08607
1966	14.6	[7]	11	11	96.4	[8]	108.7	108.7	205.1	0.6	266.5	NA	266.5	497.7	0.08864
1967	12.6	[7]	9.5	9.5	92.8	[8]	101.8	101.8	194.6	0.5	274.2	NA	274.2	491.4	0.02889
1968	11.2	[7]	8.8	8.8	91.3	[8]	100.4	100.4	191.6	0.4	297.8	NA	297.8	509.8	0.08607
1969	10.6	[7]	8.3	8.3	93.4	[8]	93.1	93.1	186.6	0.3	310.6	NA	310.6	516.4	0.04298
1970	9	[7]	7.1	7.1	96.5	[8]	90.2	90.2	186.6	0.3	320.2	NA	320.2	523.2	0.03091
1971	7.4	[7]	7.8	7.8	83.2	[8]	75.6	75.6	158.9	0.2	327.3	NA	327.3	501.6	0.02217
1972	5	[7]	6.7	6.7	87.7	[8]	72.9	72.9	160.6	0.2	351.8	NA	351.8	524.3	0.07485
1973	4.1	[7]	7	7	94.1	[8]	68	68	162.1	0.1	389.2	NA	389.2	562.6	0.10631
1974	3.7	[7]	7.8	7.8	90.2	[8]	64.9	64.9	155.1	0.1	391.8	NA	391.8	558.4	0.00668
1975	2.8	[7]	6.6	6.6	83.6	[8]	63.6	63.6	147.2	(s)	406	NA	406	562.6	0.03624
1976	2.6	[7]	6.3	6.3	84.7	[8]	61.8	61.8	146.5	(s)	448.4	NA	448.4	603.8	0.10443
1977	2.5	[7]	6.4	6.4	77.7	[8]	61.5	61.5	139.2	(s)	477.1	NA	477.1	625.3	0.06401
1978	2.2	[7]	7.3	7.3	71.4	[8]	63.1	63.1	134.5	[8]	481.2	NA	481.2	625.2	0.00859
1979	1.7	[7]	6.7	6.7	77.4	[8]	67.7	67.7	145.1	[8]	527.1	NA	527.1	680.5	0.09539
1980	1.4	[7]	5.1	5.1	66.7	[8]	60.3	60.3	127	[8]	569.3	NA	569.3	702.7	0.08006
1981	1.3	[7]	6.1	6.1	61	[8]	67.4	67.4	128.4	[8]	596.8	NA	596.8	732.6	0.04830
1982	1.4	[7]	6.8	6.8	40.9	[8]	64.1	64.1	105	[8]	593.7	NA	593.7	706.9	-0.00519
1983	1.4	[7]	7.1	7.1	37	[8]	66	66	103	[8]	625.2	NA	625.2	736.7	0.05306
1984	1.7	[7]	7.4	7.4	44	[8]	73.7	73.7	117.8	[8]	664.4	NA	664.4	791.3	0.06270
1985	1.7	[7]	6.1	6.1	41.1	[8]	75.4	75.4	116.4	[8]	693.8	NA	693.8	818	0.04425
1986	1.8	[7]	5.9	5.9	35.9	[8]	75.6	75.6	111.5	[8]	685.1	NA	685.1	804.2	-0.01254
1987	1.6	[7]	5.3	5.3	37	[8]	75.2	75.2	112.1	[8]	717.9	NA	717.9	836.9	0.04788

1988	1.6	[7]	5.6	5.6	41.9	[8]	76.3	76.3	118.1	[8]	758.4	NA	758.4	883.6	0.05641
1989	1.3	1.1	3.7	4.9	40.5	24.9	51.3	76.1	116.6	[8]	767.4	4.8	772.2	895	0.01187
1990	1.3	1.2	4.2	5.4	38.9	27.8	48.5	76.3	115.2	[8]	774.2	8.4	782.6	904.5	0.00886
1991	1.1	1.2	3.8	5	33.9	27	48.4	75.4	109.3	[8]	773.2	10.7	783.9	899.2	-0.00129
1992	1.1	1.2	3.9	5	32.4	28.2	45.8	74	106.4	[8]	781.2	13.9	795.1	907.7	0.01035
1993	1.1	1.4	3.7	5.1	31.3	28.9	46	74.9	106.2	[8]	816.6	15.1	831.6	944.1	0.04531
1994	0.9	1.3	3.8	5.1	31.7	29.7	45.5	75.2	106.9	[8]	821.2	17.1	838.4	951.3	0.00563
1995	0.8	1.4	3.6	5.1	33	29.4	43.7	73.1	106.1	[8]	832.9	17.3	850.2	962.1	0.01425
1996	0.7	1.7	3.6	5.3	31.7	29.4	42.3	71.7	103.4	[8]	878.8	18.1	896.9	1,006.30	0.05511
1997	0.7	1.7	4	5.8	30.2	29.9	41.7	71.5	101.7	[8]	904.2	17.1	921.4	1,029.50	0.02890
1998	0.5	1.4	2.9	4.3	28.2	28.6	38.9	67.4	95.6	[8]	920.4	16.3	936.6	1,037.10	0.01792
1999	0.6	1.5	2.8	4.3	28.1	27.8	37	64.7	92.8	[8]	924.7	16.2	940.9	1,038.60	0.00467
2000	0.5	1.5	2.1	3.7	28.9	28	37.2	65.2	94.1	[8]	967.1	18.7	985.8	1,084.10	0.04585
2001	0.5	1.4	2.4	3.9	26.1	25.6	39.5	65.3	91.3	[8]	946.1	18.4	964.4	1,060.10	-0.02171
2002	0.5	1.4	2.5	3.9	23.7	26.2	34.5	60.7	84.4	[8]	960.1	17.4	977.5	1,066.40	0.01480
2003	0.6	1.8	1.9	3.7	24.2	24.8	36.4	61.3	85.5	[8]	983.5	21.6	1,005.10	1,094.90	0.02437
2004	0.5	1.9	2.7	4.6	23.7	26.6	35.6	62.2	85.9	[8]	994.8	21.5	1,016.30	1,107.30	0.01149
2005	0.4	1.9	2.4	4.3	23.4	25.9	34.5	60.3	83.8	[8]	1,015.60	21.8	1,037.50	1,126.00	0.02091
2006	0.3	1.9	1.1	2.9	23	25.3	34.2	59.5	82.4	[8]	1,004.80	21.9	1,026.60	1,112.30	-0.01063
2007	0.4	1.9	1.2	3.2	22.7	22.5	34.1	56.6	79.3	[8]	1,022.80	22.3	1,045.10	1,128.00	0.01791

Table 2.1f Electric Power Sector Energy Consumption, 1949-2009

(Trillion Btu)

Year	Primary Consumption[1]													
	Fossil Fuels				Nuclear Electric Power	Renewable Energy[2]						Electricity Net Imports[6]	Total Primary	
	Coal	Natural Gas[3]	Petroleum[4]	Total		Hydroelectric Power[5]	Geothermal	Solar/PV	Wind	Biomass	Total			Demand
1949	1,995	569	415	2,979	0	1,349	NA	NA	NA	6	1,355	5	4,339	
1950	2,199	651	472	3,322	0	1,346	NA	NA	NA	5	1,351	6	4,679	0.07836
1951	2,507	791	400	3,697	0	1,361	NA	NA	NA	5	1,366	7	5,071	0.08378
1952	2,557	942	420	3,920	0	1,404	NA	NA	NA	6	1,411	6	5,338	0.05265
1953	2,777	1,070	514	4,362	0	1,356	NA	NA	NA	5	1,361	7	5,730	0.07344
1954	2,841	1,206	417	4,464	0	1,304	NA	NA	NA	3	1,307	8	5,780	0.00873
1955	3,458	1,194	471	5,123	0	1,322	NA	NA	NA	3	1,325	14	6,461	0.11782
1956	3,790	1,283	455	5,527	0	1,398	NA	NA	NA	2	1,400	16	6,942	0.07445
1957	3,855	1,383	496	5,737	(s)	1,480	NA	NA	NA	2	1,482	12	7,231	0.04163
1958	3,721	1,421	486	5,628	2	1,555	NA	NA	NA	2	1,557	11	7,198	-0.00456
1959	4,029	1,686	552	6,267	2	1,511	NA	NA	NA	2	1,513	12	7,794	0.08280
1960	4,228	1,785	553	6,565	6	1,569	1	NA	NA	2	1,571	15	8,158	0.04670
1961	4,355	1,889	557	6,801	20	1,621	2	NA	NA	1	1,624	8	8,453	0.03616
1962	4,622	2,035	560	7,217	26	1,780	2	NA	NA	1	1,784	2	9,029	0.06814
1963	5,050	2,211	585	7,846	38	1,737	4	NA	NA	1	1,743	(s)	9,627	0.06623
1964	5,380	2,397	634	8,411	40	1,853	5	NA	NA	2	1,859	7	10,316	0.07157
1965	5,821	2,395	722	8,938	43	2,026	4	NA	NA	3	2,033	(s)	11,014	0.06766
1966	6,302	2,696	863	9,881	64	2,028	4	NA	NA	3	2,036	4	11,985	0.08816
1967	6,445	2,834	1,011	10,290	88	2,311	7	NA	NA	3	2,321	-1	12,698	0.05949
1968	6,994	3,245	1,181	11,421	142	2,313	9	NA	NA	4	2,327	-2	13,887	0.09364
1969	7,219	3,596	1,571	12,386	154	2,614	13	NA	NA	3	2,630	4	15,174	0.09268
1970	7,227	4,054	2,117	13,399	239	2,600	11	NA	NA	4	2,616	7	16,259	0.07150
1971	7,299	4,099	2,495	13,893	413	2,790	12	NA	NA	3	2,806	12	17,124	0.05320
1972	7,811	4,084	3,097	14,992	584	2,829	31	NA	NA	3	2,864	26	18,466	0.07837
1973	8,658	3,748	3,515	15,921	910	2,827	43	NA	NA	3	2,873	49	19,753	0.06970
1974	8,534	3,519	3,365	15,418	1,272	3,143	53	NA	NA	3	3,199	43	19,933	0.00911
1975	8,786	3,240	3,166	15,191	1,900	3,122	70	NA	NA	2	3,194	21	20,307	0.01876
1976	9,720	3,152	3,477	16,349	2,111	2,943	78	NA	NA	3	3,024	29	21,513	0.05939
1977	10,262	3,284	3,901	17,446	2,702	2,301	77	NA	NA	5	2,383	59	22,591	0.05011
1978	10,238	3,297	3,987	17,522	3,024	2,905	64	NA	NA	3	2,973	67	23,587	0.04409
1979	11,260	3,613	3,283	18,156	2,776	2,897	84	NA	NA	5	2,986	69	23,987	0.01696
1980	12,123	3,778	2,634	18,534	2,739	2,867	110	NA	NA	5	2,982	71	24,327	0.01417
1981	12,583	3,730	2,202	18,516	3,008	2,725	123	NA	NA	4	2,852	113	24,488	0.00662
1982	12,582	3,312	1,568	17,462	3,131	3,233	105	NA	NA	3	3,341	100	24,034	-0.01854
1983	13,213	2,972	1,544	17,729	3,203	3,494	129	NA	(s)	4	3,627	121	24,679	0.02684
1984	14,019	3,199	1,286	18,504	3,553	3,353	165	(s)	(s)	9	3,527	135	25,719	0.04214
1985	14,542	3,135	1,090	18,767	4,076	2,937	198	(s)	(s)	14	3,150	140	26,132	0.01606
1986	14,444	2,670	1,452	18,566	4,380	3,038	219	(s)	(s)	12	3,270	122	26,338	0.00788
1987	15,173	2,916	1,257	19,346	4,754	2,602	229	(s)	(s)	15	2,846	158	27,104	0.02908
1988	15,850	2,693	1,563	20,106	5,587	2,302	217	(s)	(s)	17	2,536	108	28,338	0.04553
1989[7]	16,137	3,173	1,703	21,013	5,602	2,808	308	3	22	232	3,372	37	30,025	0.05953
1990	16,261	3,309	1,289	20,859	6,104	3,014	326	4	29	317	3,689	8	30,660	0.02115
1991	16,250	3,377	1,198	20,825	6,422	2,985	335	5	31	354	3,710	67	31,025	0.01190
1992	16,466	3,512	991	20,968	6,479	2,586	336	4	30	402	3,360	87	30,893	-0.00425
1993	17,196	3,538	1,124	21,857	6,410	2,861	351	5	31	415	3,662	95	32,025	0.03664
1994	17,261	3,977	1,059	22,297	6,694	2,620	325	5	36	434	3,420	153	32,563	0.01680
1995	17,466	4,302	755	22,523	7,075	3,149	280	5	33	422	3,889	134	33,621	0.03249
1996	18,429	3,862	817	23,109	7,087	3,528	300	5	33	436	4,305	137	34,636	0.03025
1997	18,905	4,126	927	23,957	6,597	3,681	309	5	34	446	4,375	116	35,045	0.01175
1998	19,216	4,675	1,306	25,197	7,068	3,241	311	5	31	444	4,032	88	36,385	0.03824
1999	19,279	4,902	1,211	25,393	7,610	3,218	312	5	46	453	4,034	99	37,136	0.02064
2000	20,220	5,293	1,144	26,656	7,862	2,768	296	5	57	453	3,579	115	38,214	0.02903
2001	19,614	5,458	1,277	26,346	R8,029	2,209	289	6	70	337	2,910	75	37,362	-0.02230
2002	19,783	5,767	961	26,511	R8,145	2,650	305	6	105	380	3,445	72	38,173	0.02171
2003	20,185	5,246	1,205	26,636	7,959	2,781	303	5	115	397	3,601	22	38,218	0.00118
2004	20,305	5,595	1,212	27,112	8,222	2,656	311	6	142	388	3,503	39	38,876	0.01722
2005	20,737	6,015	1,235	27,986	R8,161	2,670	309	6	178	406	3,566	84	39,800	0.02377
2006	20,462	6,375	648	27,485	R8,215	2,839	306	5	264	412	3,827	63	39,590	-0.00528
2007	20,808	7,005	657	28,470	R8,455	2,430	308	6	341	423	3,508	107	40,540	0.02400
2008	R20,513	R6,828	R468	R27,810	R8,427	R2,494	R314	R[illegible]	R546	R435	R3,795	112	40,147	-0.00969
2009P	18,298	7,039	390	25,725	8,349	2,663	320	8	697	426	4,113	117	38,304	-0.04591

[1] See "Primary Energy Consumption" in Glossary

[2] See Table 10.2c for notes on series components

[3] Natural gas only; excludes the estimated portion of supplemental gaseous fuels. See Note 1, "Supplemental Gaseous Fuels," at end of Section 6.

[4] See Table 5.14c for series components.

[5] Conventional hydroelectric power

[6] Net imports equal imports minus exports.

[7] Through 1988, data are for electric utilities only. Beginning in 1989, data are for electric utilities and independent power producers.

R=Revised. P=Preliminary. NA=Not available. (s)=Less than 0.5 trillion Btu

Notes: • Data are for fuels consumed to produce electricity and useful thermal output. • The electric power sector comprises electricity-only and combined-heat-and-power (CHP) plants within the NAICS 22 category whose primary business is to sell electricity, or electricity and heat, to the public. See Note 3, "Electricity Imports and Exports," at end of Section 8. • Totals may not equal sum of components due to independent rounding

Sources: Tables 5.14c, 6.5, 7.3, 8.1, 8.2b, 10.2c, A4, A5, and A6.

	UK Natural Gas Futures	Newcastle Coal Futures	ECX EUA	UK Base Electricity
Jun11	56	126.45	15.25	49.12
Sep11	56.14	125.6	15.36	49.52
Dec11	67.3	125.1	15.45	53.85
Mar12	66.48	124.2	15.61	55.72
Jun12	59.58	123.5	15.77	51.32
Sep12	60.25	123.1	15.93	51.32
Dec12	65.01	122.7	16.08	55.48
Mar13	68.56	122.15	16.38	55.48
Jun13	61.61	122.2	17.07	52.43
Dec13	66.28	122.2	17.28	57
Dec14	70.47	122.2	18.18	60.52

Percentage Changes

	UK Natural Gas Futures	Newcastle Coal Futures	ECX EUA	UK Base Electricity
Jun11				
Sep11	0.25%	-0.67%	0.72%	0.81%
Dec11	19.88%	-0.40%	0.59%	8.74%
Mar12	-1.22%	-0.72%	1.04%	3.47%
Jun12	-10.38%	-0.56%	1.02%	-7.90%
Sep12	1.12%	-0.32%	1.01%	0.00%
Dec12	7.90%	-0.32%	0.94%	8.11%
Mar13	5.46%	-0.45%	1.87%	0.00%
Jun13	-10.14%	0.04%	4.21%	-5.50%
Dec13	7.58%	0.00%	1.23%	8.72%
Dec14	6.32%	0.00%	5.21%	6.18%

	Natural Gas	Coal	Carbon	Power
Natural Gas	1.00	0.09	-0.23	0.88
Coal		1.00	0.69	0.19
Carbon			1.00	-0.14
Power				1.00

	Natural Gas	Coal	Carbon	Power	Demand
Natural Gas	1	0.09	-0.23	0.88	seasonal
Coal		1	0.69	0.19	0.74
Carbon			1	-0.14	0.5
Power				1	0.75
Demand					1

European Futures
European Futures/US Data validated
US Data
Hypothesized

Dec11	15.57	15.63	15.41	15.45
Dec12	16.19	16.23	16.07	16.08
Dec13	17.38	17.4	17.26	17.28
Dec14	18.3	18.3	18.24	18.18
Dec15				19.08
Dec16				19.98
Dec17				20.88
Dec18				21.78
Dec19				22.7
Dec20				23.65
Jun11				15.25
Jun12				15.77
Jun13				17.07

Mar11	15.25	15.25	15.1	15.17
Mar12				15.61
Mar13				16.38
Sep11				15.36
Sep12				15.93

	Natural Ga	Coal	Carbon	Power
Jun11	1	1	1	1
Sep11	1.0025	0.993278	1.007213	1.008143
Dec11	1.201786	0.989324	1.013115	1.096295
Mar12	1.187143	0.982206	1.023607	1.134365
Jun12	1.063929	0.976671	1.034098	1.044788
Sep12	1.075893	0.973507	1.04459	1.044788
Dec12	1.160893	0.970344	1.054426	1.129479
Mar13	1.224286	0.965994	1.074098	1.129479
Jun13	1.100179	0.96639	1.119344	1.067386
Dec13	1.183571	0.96639	1.133115	1.160423
Dec14	1.258393	0.96639	1.192131	1.232085

	US Power	US Nat Ga	US Coal
2001	35.0	4	25.36
2002	27.0	2.95	26.57
2003	37.5	4.88	26.73
2004	43.2	5.46	30.56
2005	63.8	7.33	36.8
2006	56.2	6.39	39.32
2007	61.7	6.25	40.8
2008	72.7	7.97	51.39
2009	38.7	3.67	54.25
2010	47.2	4.16	44

	US Power	US Nat Ga	US Coal
2001			
2002	-0.229134	-0.2625	0.047713
2003	0.387767	0.654237	0.006022
2004	0.153458	0.118852	0.143285
2005	0.476613	0.342491	0.204188
2006	-0.120248	-0.12824	0.068478
2007	0.098162	-0.021909	0.03764
2008	0.178876	0.2752	0.259559
2009	-0.467223	-0.539523	0.055653
2010	0.219474	0.133515	-0.18894

Us Nat Gas	0.94
US Coal Pc\	0.12