In the Matter of:

THE APPLICATION OF LOUISVILLE GAS AND	)
ELECTRIC COMPANY FOR CERTIFICATES	)
OF PUBLIC CONVENIENCE AND NECESSITY	) CASE NO.
AND APPROVAL OF ITS 2011 COMPLIANCE	) 2011-00162
PLAN FOR RECOVERY BY ENVIRONMENTAL	)
SURCHARGE	)

Response to the Commission Staff's First Information Request dated July 12, 2011

One Paper Copy for Question No. 32(h)

Filed – September 23, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to Commission Staff's First Information Request Dated July 12, 2011

Case No. 2011-00162

Question No. 32

Witness: John N. Voyles, Jr.

Q-32. Refer to Voyles Testimony. Provide the following information for each unit proposed for the addition of AQC equipment:

a. Year placed in service;

b. The number of normal cycles (stops and starts);

c. The number of emergency trips and starts;

d. Heat rate;

e. Capacity factor;

f. Provide for the last 10 years of major internal and minor outages including the major projects completed during each outage;

g. Provide an outline of the major availability and performance detractors;

h. Provide a condition assessment that includes;

(1) Condition of turbine.

(2) Condition of generator.

(3) Condition of boiler.

(4) Condition of balance of plant equipment.

i. Provide any formal life assessment or extension reports.

A-32. a. The requested information is contained in the table below.

Unit	**In-Service Date**
Mill Creek 1	08/01/72
Mill Creek 2	07/01/74
Mill Creek 3	08/01/78
Mill Creek 4	09/01/82
Trimble County 1	12/23/90

b. The requested information is contained in the table below.

Actual Unit Starts

Unit	**2010**
Mill Creek 1	22
Mill Creek 2	20
Mill Creek 3	14
Mill Creek 4	22
Trimble County 1	24

Source: Micro *GADS* NERC data.

c. The requested information is contained in the table below. Please note that emergency starts are not applicable to these coal units.

Actual NERC "U1" *(Immediate)* Forced Outages

Unit	**2010**
Mill Creek 1	14
Mill Creek 2	8
Mill Creek 3	8
Mill Creek 4	14
Trimble County 1	19

Source: Micro *GADS* NERC data.

d. The requested information is contained in the table below.

Actual NERC Net Heat Rate

Unit	2010
Mill Creek 1	10,684
Mill Creek 2	10,845
Mill Creek 3	10,738
Mill Creek 4	10,518
Trimble County 1	10,695

Source: Micro *GADS* NERC data and station reports.

e. The requested information is contained in the table below.

Actual NERC Net Capacity Factor

Unit	2010
Mill Creek 1	75.69
Mill Creek 2	79.95
Mill Creek 3	84.45
Mill Creek 4	78.90
Trimble County 1	80.82

Source: Micro *GADS* NERC data.

f. In response, please find attached a list of major capital projects performed during an outage in the last ten years. The Company is providing the requested information under a Petition for Confidential Protection being filed with the Commission.

g. The requested information is contained in the table below.

2010 Events > 20,000 MWh by Unit:

Unit Name	Event Type	Event Start	Event End	Event Hours	MWH Lost	Event Cause
MC3	U1	1/17/10 6:46	1/19/10 21:51	63.08	25,044	ECONOMIZER LEAKS
MC3	MO	10/29/10 21:55	11/1/10 2:47	52.87	20,988	WET SCRUBBER/ABSORBER TOWER OR MODULE
MC3	MO	9/3/10 23:58	9/6/10 2:45	50.78	20,161	OTHER INDUCED DRAFT FAN PROBLEMS
MC4	MO	6/29/10 2:05	7/2/10 22:47	92.70	45,608	OTHER EXCITER PROBLEMS
MC4	MO	11/11/10 22:45	11/15/10 9:55	83.17	40,918	AIR HEATER FOULING (REGENERATIVE)
MC4	U1	12/12/10 17:16	12/16/10 4:05	82.82	40,746	FIRST SUPERHEATER LEAKS
MC4	MO	6/4/10 22:56	6/8/10 2:48	75.87	37,326	AIR HEATER (REGENERATIVE)
TC1	U1	1/17/10 11:09	2/3/10 15:32	412.38	212,377	GENERATOR HYDROGEN SEALS
TC1	U2	5/3/10 11:23	5/8/10 7:50	116.45	59,972	FIRST REHEATER LEAKS
TC1	U1	6/18/10 8:51	6/21/10 15:59	79.13	40,754	FIRST REHEATER LEAKS
TC1	MO	10/1/10 23:01	10/4/10 22:00	70.98	36,556	FIRST REHEATER LEAKS
TC1	U1	6/14/10 4:23	6/16/10 7:40	51.28	26,411	FIRST REHEATER LEAKS
TC1	SF	10/4/10 22:00	10/6/10 21:47	47.78	24,608	TURBINE LUBE OIL PUMPS
TC1	U2	2/27/10 18:47	3/1/10 14:15	43.47	22,385	FIRST REHEATER LEAKS
TC1	U3	6/5/10 3:27	6/6/10 20:12	40.75	20,986	SECOND SUPERHEATER LEAKS

h. Please see the attached CD in folder titled Question 32(h).

i. Please see the attached CD in folder titled Question 32(i).

EON

Technical Due Diligence

Summary Report (Final Draft)

September 2008

Black & Veatch Corporation
3550 Green Court
Ann Arbor, Michigan 48105

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Building a world of difference®

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1.0 Executive Summary

1.1 Introduction

This independent technical and environmental assessment of power generation facilities, currently owned by Louisville Gas & Electric (LG&E) and/or Kentucky Utilities Company (KU), has been prepared by Black & Veatch Corporation (Black & Veatch) on behalf of E.ON US LLC (EON). Both LG&E and KU are regulated utilities wholly owned by EON. The power generation facilities are listed in Table 1.1-1 by unit type. The locations of the generating facilities are shown on Figure 1.1-1.

The portfolio comprises approximately 9,529 MW of generation facilities (based on generator nameplate ratings) with 9,197.5 MW EON ownership. The facilities are located in the state of Kentucky. All of the power generation facilities evaluated in this assessment are currently in operation except for the Trimble County Unit 2 (TC2) facility. TC2 is a 760 MW pulverized coal fired facility, which is currently under construction and is expected to achieve commercial operation in 2010.

1.2 Scope of Work

To conduct this due diligence, Black & Veatch provided the following services:

- An assessment of the respective facilities' conditions based on site visits and reviews of operations and maintenance (O&M) documentation provided by EON.
- A performance assessment of the facilities, such as plant outputs, heat rates, availabilities, and forced outage rates.
- A review of O&M practices and capital projects.
- A summary review of key contracts and agreements provided by EON.
- A review of regulatory, permitting, and environmental compliance.
- A review of the engineering, procurement, and construction (EPC) contract for TC2 to assess the terms of the EPC contract and the ability of the contractor to perform under the agreement.

Black & Veatch reviewed the documentation provided by EON; visually inspected the operating facilities; interviewed plant personnel in the areas of operations and maintenance; and observed equipment condition, environmental compliance, performance, and availability. Additional data were either collected or requested when not readily available. The plant component testing and inspection reports/results were also reviewed to verify equipment condition. The conclusions that resulted from the due diligence effort are summarized in this report.

Table 1.1-1
EON Power Generation Facilities

Unit Name	Unit Type[(1)]	In-Service Date	Ownership, % KU	Ownership, % LG&E	Generator Nameplate Ratings, MW
Brown 1	Pulverized Coal	5/1/1957	100		114
Brown 2	Pulverized Coal	6/1/1963	100		180
Brown 3	Pulverized Coal	7/1/1971	100		446
Cane Run 4	Pulverized Coal	5/1/1962		100	164
Cane Run 5	Pulverized Coal	5/1/1966		100	209
Cane Run 6	Pulverized Coal	5/1/1969		100	272
Ghent 1	Pulverized Coal	2/1/1974	100		557
Ghent 2	Pulverized Coal	4/1/1977	100		556
Ghent 3	Pulverized Coal	5/1/1981	100		557
Ghent 4	Pulverized Coal	8/1/1984	100		556
Green River 3	Pulverized Coal	4/1/1954	100		75
Green River 4	Pulverized Coal	7/1/1959	100		114
Mill Creek 1	Pulverized Coal	8/1/1972		100	356
Mill Creek 2	Pulverized Coal	7/1/1974		100	356
Mill Creek 3	Pulverized Coal	8/1/1978		100	463
Mill Creek 4	Pulverized Coal	9/1/1982		100	544
Trimble County 1	Pulverized Coal	12/23/1990		75	566
Trimble County 2	Pulverized Coal	Mid 2010	60.75	14.25	760
Tyrone 3	Pulverized Coal	7/1/1953	100		75
Brown 5	Natural Gas - CT	6/8/2001	47	53	123
Brown 6 & 7	Natural Gas - CT	Aug 1999	62	38	354
Brown 8	Natural Gas - CT	2/1/1995	100		126
Brown 9	Natural Gas - CT	8/1/1994	100		126
Brown 10	Natural Gas - CT	12/1/1995	100		126
Brown 11	Natural Gas - CT	5/1/1996	100		126
Cane Run 11	Natural Gas - CT	6/1/1968		100	16
Haefling 1, 2, & 3[(2)]	Natural Gas - CT	10/1970	100		63
Paddy's Run 11 & 12	Natural Gas - CT	Mid 1968		100	49
Paddy's Run 13	Natural Gas - CT	6/27/2001	47	53	178
Trimble County 5 & 6	Natural Gas - CTs	5/14/2002	71	29	398
Trimble County 7 - 10	Natural Gas - CTs	Mid 2004	63	37	796
Zorn 1[(2)]	Natural Gas - CTs	5/1/1969		100	18
Dix Dam 1, 2, & 3	Hydro Units	11/1/1925	100		27
Ohio Falls 1 thru 8	Hydro Units	1/1/1928		100	83
Total Generation Capacity based on Generator Nameplate Ratings					9,529

[(1)] CT = Combustion Turbine.
[(2)] Black & Veatch did not perform due diligence review of these generating assets.

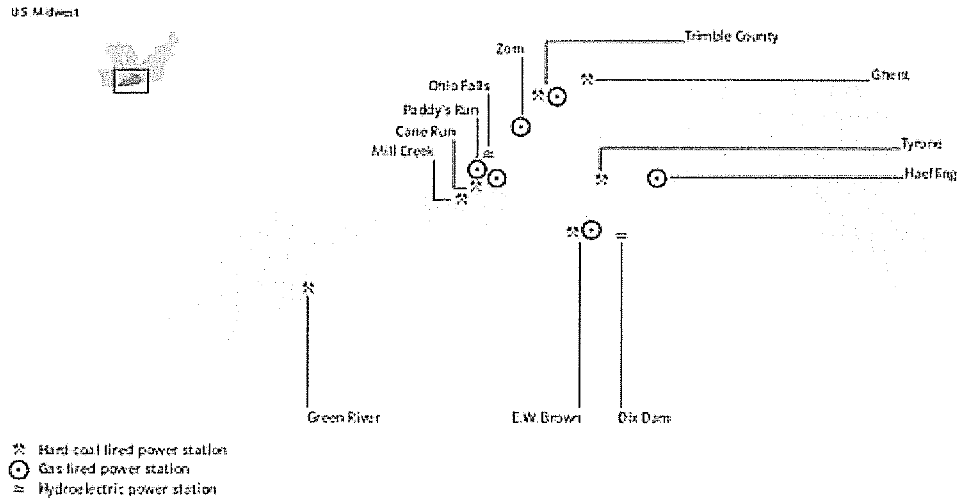

Figure 1.1-1
EON Power Generation Facility Locations
(Source: EON Web site)

1.3 Conclusions

Based on a limited assessment of the facilities, Black & Veatch has reached several conclusions, as summarized in the following subsections.

1.3.1 Plant Design and Construction

Based on documentation reviewed, observations made during site visits, and interviews with plant personnel, the plants appear to be well designed and constructed, and have demonstrated the capability to operate as intended and as required to serve EON network customers.

1.3.2 Plant Condition

With respect to the condition and remaining useful life of the operating facilities, Black & Veatch's opinion is based on the documentation reviewed as of the date of this report, the plant site visits, interviews with plant personnel, and the assumption that the units continue to be operated and maintained in accordance with industry standards, as well as the recommendations and guidelines of the original equipment manufacturers (OEMs). Based on that information and those assumptions, the operating facilities at Brown and Trimble County, utilizing newer combustion turbine (CT) technology, are capable of continued safe and reliable operation for at least an additional 15 years. In contrast, the remaining useful life of the older CTs at Cane Run and Paddy's Run facilities can be extended by another 15 years with increased expenditures for maintenance expenses, including repairs and replacement of selected parts. Again, based on the information provided, site visits, interviews, and the assumption the units will continue to be maintained in accordance with industry and OEM standards, the majority of the coal fired operating facilities are capable of continued safe and reliable operation for at least an additional 15 years. However, the older units will require additional attention in the form of timely capital investment for repair/replacement of specific aging components. The remaining useful economic life of the oldest units, especially the Tyrone Generating Station and the Green River Generating Station, could be impacted by the resolution of the currently uncertain future air emission requirements, should that resolution dictate the addition of costly emissions controls. The concern is that such an investment may not be economically justified on these units.

1.3.3 Performance

EON develops projected performance for each generating station with due consideration of condition assessment and planned capital expenditure. In general, the projected performance of the operating facilities reflects historical performance and is consistent with industry norms.

1.3.4 Operations and Maintenance

Based on interviews with plant personnel, onsite observations, and reviews of documentation, the facilities' operations and maintenance programs are reasonable and sufficient to support current and projected plant operation. EON has recently instituted various programs, including operating procedures, succession plans, operating plans, and training programs, designed to improve the reliability and enhance the long-term value of all of the generating assets.

1.3.5 Environmental Compliance

Based on the documentation provided for review, the operating facilities are generally operating in compliance with the requirements of applicable permits and are not generally subject to any current or foreseen legal action associated with environmental impacts. The only exception is Unit 3 of the E.W. Brown Generating Station, which is in litigation with regard to an alleged New Source Review (NSR) violation. The outcome of this litigation cannot be predicted at this time since the litigation is still ongoing.

1.3.6 Projected Performance and Operating Costs

EON projected performance targets are based upon successful implementation of the identified capital budget projects. Black & Veatch review indicated that EON 2008 through 2012 planned capital projects and associated costs are mostly reasonable, based on the projected performance requirements as well as past repair, replacements, maintenance, inspection, and testing records. The identified capital projects included nearly all necessary critical major projects. Capital projects related to emission controls will need to be evaluated and adjusted in light of any regulations that will be enacted to fill the void of the recently vacated Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR) regulations. Since EON has already committed extensive capital costs to upgrading or adding air quality control systems on many plants, future capital costs that would be incurred by EON generally would be expected to be equivalent to other electric utilities that have large coal fired units. However, legislation at either the state or national level to regulate the emissions of greenhouse gases (GHGs), such as carbon dioxide (CO_2), has the potential to impact EON as well as other utilities that have large coal fired units by imposing limits on GHG emissions, requiring costly equipment and sequestration of CO_2 emissions, and requiring other methods to address climate change that would result in additional costs to ensure compliance with these regulatory programs.

With respect to the operating costs, the nonfuel O&M costs appear reasonable. For the most part, the significant maintenance issues that have been identified or anticipated have been addressed in the budget plans. Air emissions-related operating costs are uncertain due to the recent vacating of CAIR and CAMR regulations. The budgets will require adjustment depending on when, and to what extent, the recently installed controls will be required to be operated and to what extent new emissions controls may be required by any regulations enacted to fill the void of these recently vacated regulations. Since other eastern US coal fired plants would be subject to the same regulations, the additional future operating costs incurred by EON generally would be expected to be comparable to other electric utilities that have large coal fired units.

EON-projected fuel costs for the planning period through 2012 appear to be reasonable based upon Black & Veatch review of the long-term fuel contracts, as well as a high-level comparison of the average projected fuel costs against EON system wide historical average fuel costs.

2.0 Coal Fired Generating Plants

2.1 Trimble County Generating Station

2.1.1 Introduction

Trimble County Generating Station Unit 1 (TC1) is a 566 MW pulverized coal fired power plant located approximately 5 miles west of Bedford, Kentucky. The site location is illustrated on Figure 2.1-1. TC1, which began commercial operation in December 23 1990, is situated on approximately 1,004 acres. An additional 760 MW coal plant (TC2) is under construction on the site and is due to be completed on June 15, 2010.

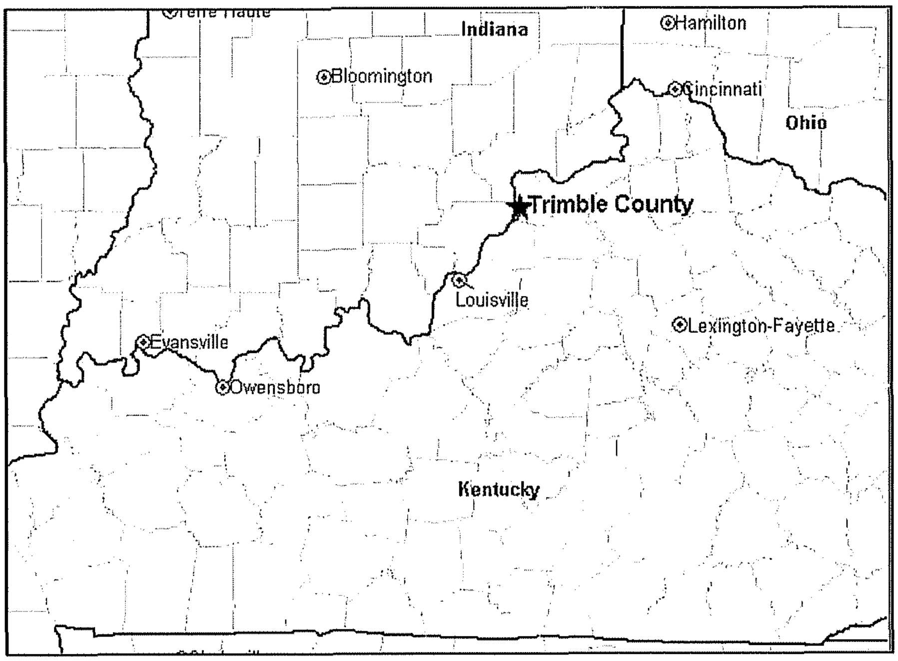

Figure 2.1-1
Trimble County Generating Station Location

TC1 consists of one Combustion Engineering (CE) tangential balanced draft, forced circulation boiler and one General Electric (GE) reheat double-flow steam turbine with a hydrogen-cooled generator. Table 2.1-1 provides a summary of the Trimble County plant facts.

Table 2.1-1
Trimble County Generating Station Units 1 and 2 Fact Sheet

Category	Data	Category	Data
Location:	Bedford, KY	**Market Area:**	Midwest
Nominal Capacity(1):	513 MW net (Unit 1) 1273.5 MW net (Units 1and 2)	**Off-Take:**	EON network customers
Ownership:	TC1 - LG&E - 75%: TC2 – LG&E/KU - 75% IMPA/IMEA - 25%	**Electric Interconnection:**	Trimble County 345kV Substation
Fuel:	Coal	**Fuel Supply:**	Contract and spot
Type:	Pulverized coal fired steam generator	**COD:**	December 23, 1990 (Unit 1) June 15, 2010 (Unit 2)
Equipment:	1 x CE boiler and 1 x GE steam turbine (Unit 1); 1x Doosan-Babcock supercritical boiler and 1x Hitachi steam turbine (Unit 2 - 2010)	**Operator:**	LG&E

Notes:
1. Nominal Capacity represents 100 percent of average (winter, summer) net electrical output.

The project is owned by LG&E (75 percent) and Illinois Municipal Electric Agency/Indiana Municipal Power Agency (IMEA/IMPA) (25 percent). TC1 is designated as a network resource generating unit on the EON transmission system. The full load output from this unit can be used to serve the network customers interconnected to EON's transmission system.

TC1 has electrical interconnection through the Trimble County 345 kV substation. The unit burns high sulfur coal delivered by barge tow. The fuel supply is provided through a combination of fuel supply contracts and the spot market.

Process water makeup is withdrawn from the Ohio River. The water is used for plant service water, potable water, fire water, makeup for the cooling tower, and makeup to the steam/condensate cycle.

2.1.2 Plant Description and Design

Siting and Real Estate

TC1 is located approximately 5 miles west of Bedford, Kentucky, at the intersection of State Highways 754 and 1838. The facility is located on the bank of the Ohio River, 1 mile north of Wises Landing. The entire site covers 2,172 acres. The active plant site, which covers 1,004 acres, is bordered by Corn Creek to the north, State

Highway 754 to the south, State Highway 1838 (Corn Creek Road) on the east, and the Ohio River to the west. An aerial view of the site is shown on Figure 2.1-2.

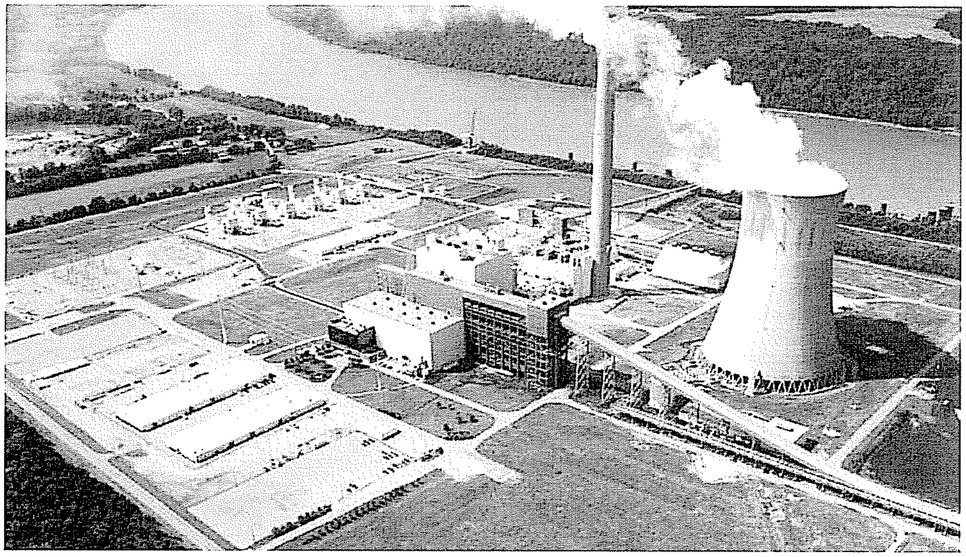

Figure 2.1-2
Trimble County Generating Station

Equipment

TC1 is a pulverized coal thermal plant consisting of one high sulfur, coal fired steam-electric generating unit that is rated at 566 MW. The major plant equipment is listed in Table 2.1-2.

Boiler

The boiler is a CE tangential balanced draft, forced circulation boiler with a reheater originally designed to fire high sulfur Western Kentucky bituminous coal. The unit was designed for a maximum continuous main steam flow of 3,807,000 lb/h of steam at 2,620 psig and 1,005° F, with a reheat steam flow of 3,390,000 lb/h and a steam temperature of 1,005° F. TC1 receives coal from six pressure mills, of which four are generally required to achieve a maximum continuous rating (MCR).

Steam Turbine Generators

The TC1 steam turbine is a GE reheat tandem compound, double-flow turbine rated for 2,400 psig and 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 566 MW gross average output.

Table 2.1-2
Trimble County Generating Station Unit 1 Major Equipment

Description	Quantity	Characteristics
Boiler	1	One CE tangential balanced draft, forced circulation boiler with reheater originally designed to fire high sulfur Western Kentucky bituminous coal, rated for 3,807,000 lb/h of steam at 2,620 psig and 1,005° F
Steam Turbine	1	One GE reheat tandem compound, double-flow turbine rated for 2,400 psig and 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 547 MW gross average
Draft System	2	Forced draft (FD) fans (50 percent nom.) Ljungstrom rotating, regenerative type, vertical shaft, air heaters (50 percent nom.) Induced-draft (ID) fans with variable speed drives (50 percent nom.)
Condenser	1	Two-pass vacuum condenser
Circulating Water System	2 1	Circulating water pumps (50 percent nom.) Mechanical draft cooling tower
Generator	1	GE, Model 280T105, rated 629 MVA, 22 kV, 460 V excitation, H_2/water cooled, power factor (PF) = 90
Control Systems	1	Honeywell TDC-3000 and plant historian is a Honeywell PHD mode
Condensate and Feedwater Systems	3 3	50 percent vertical, centrifugal, multistage axial condensate pumps 60 percent centrifugal, barrel, multistage boiler feed pumps; two with 10,000 horsepower (hp) steam turbine drives, and one with 10,000 hp electric motor drive
Flue Gas Treatment	1 1 1	CE Electrostatic Precipitator (ESP) Riley Power selective catalytic reduction (SCR) system CE wet limestone flue gas desulfurization (FGD)
Electrical System	1	GE generator step-up (GSU) transformer rated 570/638.4 MVA, forced outside air (FOA) 55° C/65° C, 20.9 kV to 345 kV

Control Systems

The existing control system for TC1 consists of a Honeywell TDC-3000, and the unit historian is a Honeywell PHD model. The unit is approximately midway through a project to replace the existing Honeywell TDC-3000 with an Emerson system. The system replacement for TC1 will take place through 2010; some of the balance-of-plant

(BOP) systems for TC1, including water treatment, coal handling, soot blowing, and ash handling, were migrated to the new system in 2007.

Emissions Systems

The emissions control systems of TC1 include an electrostatic precipitator (ESP), flue gas desulfurization (FGD), and selective catalytic reduction (SCR) unit for the removal of solids, sulfur oxides, and nitrogen oxides (NO_x). The ESP consists of four physical cells with a design that incorporates each cell sectionalized into two electric sections. A tumbling hammer and anvil rapping system is used to remove dust buildup on the collecting plate surfaces.

TC1 has a spray tower type FGD that is original to the plant. Upgrades to the FGD system completed in 1998, and most recently by Babcock Power in the 2005 - 2006 time frame, include an inlet duct configuration change, changing of some spray nozzles to be bi-directional, and the addition of wall baffles. In addition, a dibasic acid (DBA) system has been provided to enhance system performance to compensate for the loss of a recycle pump from service. The design performance specification for the upgraded FGD system in the current operating mode is for 98 percent sulfur dioxide (SO_2) removal efficiency with coal that contains 5.5 pounds of sulfur per million Btu (MBtu), to result in SO_2 emissions of 0.11 lb/MBtu.

The SCR system is designed to reduce the outlet NO_x concentration by 90 percent. The SCR reactor uses anhydrous ammonia as a reducing reagent.

Extractive dilution type continuous emissions monitoring systems (CEMS) are installed on TC1 for measuring NO_x, SO_2, CO_2, and stack flow. An opacity monitor is also installed downstream of the ESP.

Auxiliary Systems

The station has a gypsum dewatering plant that used to be operated 7days a week, but recently the plant has been operating only 5 days a week due to the slow wallboard market. The byproduct gypsum solids produced by the dewatering plant used to be trucked 20 miles to near the Ghent plant where there is a wallboard plant; however, that situation is changing with the recent startup of FGD systems at the Ghent Generating Station. The station just signed a gypsum sales contract that consists of a 20 year minimum take of gypsum that will be equal to 50 percent of the gypsum production at the plant. This new contract requires the gypsum to be barged. The remaining gypsum byproduct will likely be land filled. Landfill options have been studied but not yet permitted.

Gypsum dewatering wash water is sent to the ash pond and not discharged from the plant. This has raised the chloride level in the ash pond, not to problem levels, but such levels are likely to be reached in the future, especially with the future operation of the new TC2. The plant has a separate waste pond to which the high chloride flow could be sent, so that the plant could discharge the high chloride water to the cooling tower blowdown. Such operating strategy is used at other plants in the United States, since the mixing of the chlorides in the cooling tower blowdown provides for chloride concentrations that can be acceptable to regulators.

The draft system consists of two FD fans, two primary air fans, and two ID fans with variable inlet guide vanes. The boiler exhausts through ductwork to a single 760 foot high stack.

Thermal cycle heat rejection is realized using a mechanical draft cooling tower. A closed water circuit cooled by a common air-cooled heat exchanger provides auxiliary cooling.

TC1 has three (60 percent) centrifugal, barrel, multistage boiler feed pumps; two with 10,000 hp steam turbine drives and one with a 10,000 hp electric motor drive. The plant also has three (50 percent) vertical, centrifugal, multistage axial condensate pumps.

Fuel Supply

Trimble County Generating Station burns high sulfur coal, which is received by barge tow. There are normally 5 to 15 barges delivered at a time. The coal is transported by conveyor and stored in a pile, which is north of the Generator Building.

Upon receipt, the coal is mechanically unloaded and added to the pile or is directly carried by conveyors to the silos of TC1.

Coal in the storage area is presently segregated. The plant maintains one pile of regular storage, one pile of middlings storage, and one pile of coal received from Williamson.

Water and Wastewater

Raw water is withdrawn from the Ohio River from an intake structure located adjacent to the coal barge unloading facility. The intake structure was originally sized to accommodate four units at this site, so there is no concern with capacity. The plant operating staff reported no concerns with the intake structure; however, the intake structure does require chemical dosing twice a year to control zebra mussels.

Though the intake does silt, since the river channel is regularly dredged to ensure a clear channel for barge traffic, silting was reported to not be a concern for plant operations.

Potable water is supplied by the Trimble County Water District No. 1.

Electrical and Interconnection

TC1 has a nominal net capacity of 513 MW, 0.90 PF. The electrical power output of the unit is delivered from a single 22 kV generator and stepped up by a generator step-up (GSU) transformer to the 345 kV transmission system. The connection from the generator to its GSU transformer is by isolated phase bus duct. The 6.9 kV auxiliary power for the unit is derived from two reserve auxiliary 138 kV-6.9 kV transformers and from one dedicated 22 kV-6.9 kV main auxiliary transformer connected to the generator bus. The reserve auxiliary transformers provide starting power to the unit; after the unit has started, auxiliary power is then derived through the main unit auxiliary transformer.

2.1.3 Performance

Table 2.1-3 lists the historical net generation, capacity factor (CF), equivalent availability factor (EAF), and equivalent forced outage rate (EFOR) for TC1. The table also lists the industry averages for capacity factor, EAF, and EFOR. Industry average data come from the Generating Availability Data System (GADS), provided by the North American Electric Reliability Corporation (NERC), and are for units in the Southern

Table 2.1-3
Historical Performance Data for Trimble County Generating Station Unit 1

	2004	2005	2006	2007	Average
Net Generation (MWh)	4,159,138	3,811,260	4,174,883	3,577,340	3,930,655
Net Heat Rate (Btu/kWh)	10,140	10,216	10,191	10,352	10,220
Capacity Factor (%)	92.6	84.9	93.0	79.7	87.5
Industry Average CF (%)					*65.2*
Equivalent Availability Factor (%)	98.4	88.1	94.3	83.7	91.1
Industry Average EAF (%)					*82.9*
Equivalent Forced Outage Rate (%)	0.5	3.0	3.3	4.0	2.7
Industry Average EFOR (%)					*7.4*

Energy Reliability Council (SERC) and Reliability First Corporation (RFC) NERC regions for the years 2000 to 2006. The industry averages are as reported for units between 450 and 650 MW.

TC1 is a baseloaded unit, as shown by the high capacity factor. Table 2.1-3 shows that the TC1 average EAF and EFOR for the years 2004 to 2007 outperformed industry averages.

2.1.4 Operations and Maintenance

The station utilizes plant-specific training materials to ensure that the station staff is familiar with station requirements. In addition, the plan also notes the need to utilize the Primedia basic skills training program.

The generating station utilizes the Maximo system (a preventative maintenance program) for maintenance management and planning. The station's O&M program focuses on managing and improving both reliability and availability similar to other units in the EON system. The station has been working to utilize more efficient links between Oracle (a database management program) and Maximo, so that naming conventions are consistent between the two major applications. In addition, the station has been utilizing the benchmarking services of UMS to define appropriate performance targets in a number of different areas throughout the plant.

The station uses Maximo for preventive maintenance management and to generate preventive maintenance tasks based on plans developed for the station equipment/systems. Black & Veatch reviewed a printout of the preventive maintenance tasks for TC1 and found the task list to be comprehensive and appropriate for a plant of this type and size.

The operating plan noted action items designed to refine the daily planning process, to improve the effectiveness of the preventive maintenance program and overall workforce application.

The station outage planning process calls for a 4 week boiler outage every 2 years and an 8 week turbine outage every 8 years. In addition, the station actively participates in the EON boiler circuit maintenance program to ensure that the biannual 4 week boiler outage addresses all known boiler issues that would be expected to compromise unit reliability if they were not addressed.

The station has a predictive maintenance management (PDM) program in place that includes periodic vibration, infra-red thermography, and dissolved oil and motor current analyses on critical station equipment. The station's O&M program also includes the application of acoustic emissions to the seam-welded, high energy piping systems.

In addition to the existing O&M programs described above, the station plans to enhance the application and documentation of its Root Cause Failure Analysis (RCFA) program to ensure that lessons are documented and applied to further improve overall station reliability and performance.

It is Black & Veatch's understanding that EON plans to introduce Powder River Basin (PRB) coal into the Trimble County Station plant. This fuel switch will require additional coordination and labor in fuel storage, blending, and handling from the coal handling facility that is common to both Units 1 and Unit 2. EON appears to have plans in place to include additional resources in the facility's operational plans to address this issue.

Overall, the station appears to have a comprehensive O&M program and sufficient resources to achieve reliable performance of the plant.

O&M Historical Expenses

The historical O&M costs for the Trimble County Generating Station are shown in Table 2.1-4. These operating costs include Trimble County Combustion Turbines (TC CTs).

Table 2.1-4
Trimble County Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$13,161	$12,217	$14,404	$15,053	$19,518
Other Cost of Services		$1,073	$1,222	$1,605	$1,683
Fuel Handling	$978	$993	$969	$1,088	$1,078
Below the Line	$61	$46	$52	$18	$155
Total Controllable	$14,200	$14,329	$16,647	$17,764	$22,434
Net Generation (GWh)	3675	4159	3811	4175	4296
Controllable/MWh	$3.86	$3.45	$4.37	$4.25	$5.22

The total headcount for the station (111 in 2008) appears consistent with industry practice in light of the fact that the plant has substantial emissions control equipment and a compliment of gas turbines at the same site. Stated plans for staff increases as TC2 comes on line are conservative and, assuming these increases are adequate, would result in a reasonably lean staff for the combined facilities.

The station provided details showing the practice of carefully monitoring and communicating monthly operating statistics, including unit performance (both thermal and reliability data), emissions and fuel details, as well as starts and operating hours. These results include current month data, year to date (YTD) performance, as well as the previous 12 month period.

SCR reagent operating costs are expected to increase by approximately 50 percent in 2009; these costs reflect year-round operation and increases that could be expected because of the planned implementation of the CAIR emission limitations in 2009. The recent vacating of the CAIR by the courts makes such operation costs unnecessary at this point, but these costs may be seen in the future, since new regulatory limitations are promulgated. Costs for this additional operation should not be overlooked as future regulatory actions occur.

2.1.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the plant on July 10, 2008. The plant facilities appeared to be in good condition. The access and space availability on the site is affected by the current ongoing construction of Unit 2, but this construction appears to be managed in a manner consistent with industry practices. The quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition with no signs of significant leakage of oil, water, or steam; corrosion damage; or other distress. Coal handling areas were noted to have more than average carryover and build-up on the bottom side of all belt conveyors, associated with settings on primary and secondary belt wipers and spillage at the Ohio River near the barge unloading area. The electrical equipment appeared to be properly maintained. Electrical rooms were clean and not used as storage for unrelated items. Battery rooms were locked and kept clean in general. The floor space in front of the switchgear was clear for operational access. The control room and plant lighting was functioning properly.

Boiler

The challenge for the TC1 boiler maintenance strategy is the erosion and falling slag abrasion damage that occurs at the boiler slope furnace tubing. These furnace water wall tube leaks were the main contributor to forced outages for 2007. To address this issue, EON is planning to replace the west side boiler slope tubes and structural steel and the east side boiler slope tubes with thicker tubes (30 percent thicker wall than original design) in 2009. EON is also currently reviewing other possible ways to solve the problem, including changing fuel sources, adjusting furnace oxygen levels, using combustion optimizations, using burner tilts, and seeking opportunities for off-line slag control.

In 2001 to 2002, TC1 was discovered to have a design manufacturing flaw with the superheater outlet header that showed excessive stub tube failures. It was determined that the header was not fabricated from the correct material (SA-335 Gr P22). The subject component was replaced in 2003, reportedly with the proper metallurgy.

Significant portions of the reheater pendant tubing were replaced and modified in 2000 to 2001, because of severe overheating and excessive use of reheat spray desuperheating. To resolve the issue, the pendants were shortened to reduce peak temperatures, and the problems appear to have been resolved, according to a review of forced outage data provided.

Steam Turbine

The steam turbine rotor has more than 137,000 hours of operation and more than 443 total starts (295 hot starts, 85 warm starts, and 63 cold starts) as of June 2008.

TC1 is scheduled for a major turbine overhaul outage in 2009. The TC1 steam turbine was last overhauled in 2001. Upgrades to the turbine first stage (high-pressure [HP]) nozzle blocks, last stage (low-pressure [LP]) buckets, and interstage packing were made that enable the unit to operate closer to GE design continuous output. The TC1 steam turbine generator is operated near the unit's gross declared maximum summer generation of 546.7 MW, with a corresponding net plant output of approximately 514 MW; the unit was operating very near that level at the time of the Black & Veatch site visit. Improvements on the turbine that were made in 2001 to meet the current output levels include first stage steam path, enhanced interstage seals, LP section (L-0) blade replacement, and first stage nozzle block tolerance. Further studies to determine additional generation available from Unit 1 up to the GE rated steam flow are being considered.

2.1.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.1. From information provided, the existing TC1 appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON has submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with its permit conditions, with the exception of one item. TC1 had four opacity exceedances greater than their 20 percent threshold due to unit upset or precipitator trouble.

Water

- As observed during the site visit by Black & Veatch, chloride buildup in the plant water system is a significant concern for the future. Gypsum dewatering wash water is sent to the ash pond and is not discharged. This practice has raised the chloride level in the ash pond. In its Kentucky Pollutant Discharge Elimination System (KPDES) Permit renewal application, EON has applied for a change in the permit to allow gypsum impoundment water to be pumped to the cooling tower blowdown outfall, but the renewed/revised permit has not yet been issued.

Other

- Long-term disposal of gypsum byproduct from the FGD process has not been fully resolved. EON currently has a gypsum sales contract that consists of a 20 year minimum take of gypsum, which is equivalent to 50 percent of the gypsum production at the plant. The remaining gypsum byproduct will likely be landfilled. Landfill options have been studied but not yet permitted.
- Black & Veatch understands that EON is aware of these issues and steps to resolve the landfill needs of the station are already underway.

2.1.7 Key Findings

- The Trimble County Station appears to have the required environmental permits in place and to be operating in substantial compliance with permit and regulatory requirements.
- The Trimble County Station meets current air emissions regulations and is well positioned to meet future air regulations, such as the CAIR and the CAMR. It is assumed that EON will plan and implement strategies to comply with any future versions of these two rules. The two environmental issues for the station are the disposal of byproduct and the

disposal/treatment of high chloride wastewater that may be generated. Black & Veatch understands that EON is aware of these issues and steps to resolve the landfill needs of the station are already underway.

- The introduction of PRB coal into the Trimble County Station plant will require additional coordination and labor in fuel storage, blending, and handling from the coal handling facility that is common to both Units 1 and Unit 2. EON appears to have plans in place to include additional resources in the facility's operational plans to address this issue.
- The challenge for the TC1 boiler maintenance strategy is the erosion and falling slag abrasion damage that occurs at the boiler slope furnace tubing. These furnace water wall tube leaks were the main contributor to forced outages in 2007. To address this issue, EON is planning to replace the west side boiler slope tubes and structural steel and the east side boiler slope tubes with thicker tubes (a 30 percent thicker wall than the original design) in 2009. EON is also currently reviewing other possible ways to solve the problem, including changing fuel sources, adjusting furnace oxygen levels, using combustion optimizations, using burner tilts, and seeking opportunities for off-line slag control.
- The data provided indicate that the station outage planning process includes a 4 week boiler outage every 2 years and an 8 week turbine outage every 8 years. This is considered somewhat aggressive but achievable in the sense that, while it provides sufficient time for maintenance, inspection, and few repair activities, it does not afford many opportunities to conduct boiler repair activities discovered during the outages.

2.2 Mill Creek Generating Station

2.2.1 Introduction

The Mill Creek Station is located in southwestern Jefferson County, approximately 10.5 miles southwest of the city of Louisville, Kentucky, on a 509 acre site. The site location is illustrated on Figure 2.2-1. Mill Creek Station includes four coal fired electric generating units with a gross total generating capacity of 1,628 MW. Mill Creek Station Unit 1 (MC1) was placed in service in 1972, Mill Creek Station Unit 2 (MC2) was placed in service in 1974, and Mill Creek Station Units 3 and 4 (MC3 and MC4) were each placed in service at 4 year intervals afterward in 1978 and 1982, respectively.

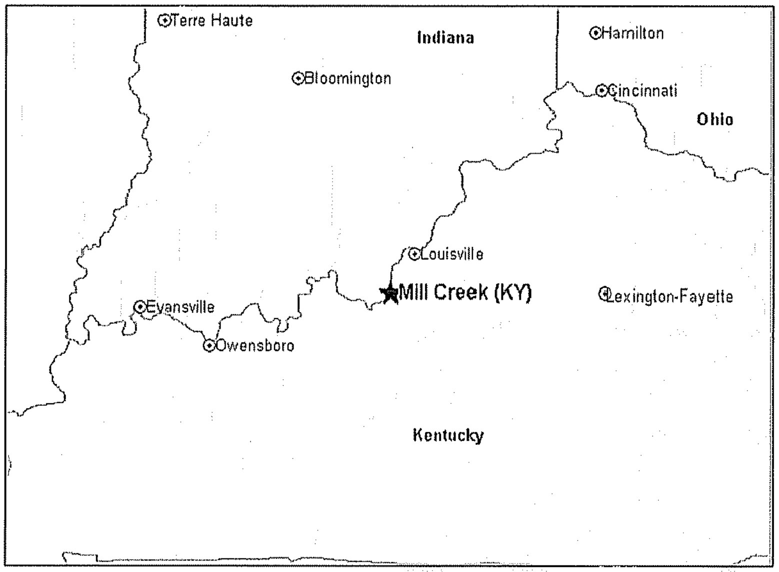

Figure 2.2-1
Mill Creek Generating Station Location

The Mill Creek Station consists of four coal fired electric generating units. All four boilers fire high sulfur bituminous coal. Each Mill Creek Station unit is composed of one GE reheat tandem compound, double-flow turbine with a condenser and hydrogen-cooled generator. MC1 and MC2 each consist of one CE subcritical, balanced draft boiler. MC3 and MC4 each consist of one Babcock & Wilcox (B&W) balanced draft, Carolina type radiant boiler. Table 2.2-1 provides a summary of the Mill Creek Station plant facts.

2.2.2 Plant Description and Design

Siting and Real Estate

The Mill Creek Station is located in southwestern Jefferson County, approximately 10.5 miles southwest of the city of Louisville, Kentucky, on a 509 acre site. Mill Creek Station includes four coal fired electric generating units with a gross total generating capacity of 1,628 MW and a declared net summer capacity of 1,472 MW. The Mill Creek Station is immediately adjacent to, and can be accessed from, Highway 31 W South, also called the Dixie Highway. The Mill Creek Station is also located on the south bank of the Ohio River and has rail line access. This location makes Mill Creek the only station in the LG&E/KU system able to receive coal both by barge and rail. An aerial view of the facility is shown on Figure 2.2-2.

Table 2.2-1
Mill Creek Plant Fact Sheet

Category	Data	Category	Data
Location:	Jefferson County, KY 11 miles southwest of Louisville	**Market Area:**	Midwest
Nominal Capacity:	1481.5 MW net	**Off-Take:**	EON network customer
Ownership:	LG&E - 100 %	**Electric Interconnection:**	Mill Creek 345 kV Substation
Fuel:	Coal	**Fuel Supply:**	Contract and spot
Type:	Pulverized coal, sub-critical fired steam generators	**COD:**	August 1, 1972 (Unit 1) July 1, 1974 (Unit 2) August 1, 1978 (Unit 3) September 1, 1982 (Unit 4)
Equipment:	2 x CE boilers, 2 x B&W boilers, and 4 x GE steam turbines	**Operator:**	LG&E

Notes:
1. Nominal Capacity represents 100 percent of average (winter, summer) net electrical output.

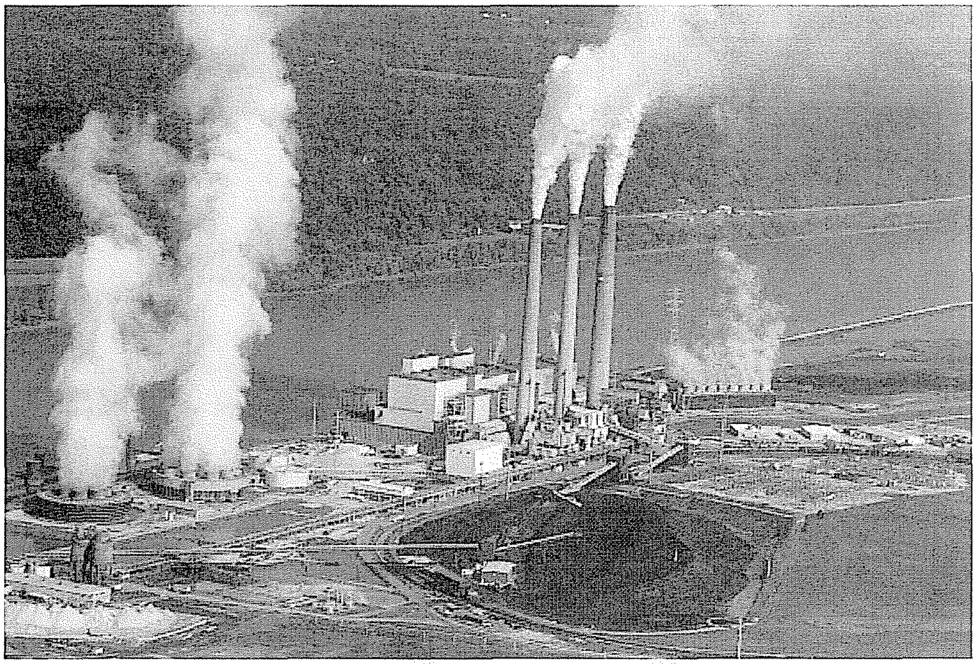

Figure 2.2-2
Mill Creek Generating Station

Equipment

The Mill Creek Station consists of four coal fired electric generating units with a gross generating capacity of 1,628 MW. All four boilers fire high sulfur bituminous coal. The boilers, turbines, and generators are located within the powerhouses. The unit details are as listed in Table 2.2-2.

Boilers

The MC1 and MC2 boilers are CE subcritical, balanced draft boilers with a reheater originally designed to fire high sulfur Midwestern bituminous coal, at a main steam flow MCR of 2,326,000 lb/h at 2,600 psig and 1,005° F.

The MC3 and MC4 boilers are B&W balanced draft, Carolina type radiant boilers with a reheater originally designed to fire high sulfur bituminous coal, at a main steam flow maximum continuous rating of 3,144,000 lb/h for Unit 3 and 3,660,000 lb/h for Unit 4, both at 2,600 psig and 1,005° F.

Steam Turbine Generators

The MC1 and MC2 steam turbines are GE reheat tandem compound, double-flow, rated for nominal 2,400 psig 1,000° F steam, with a condenser and hydrogen-cooled generator nameplate rating of 356 MW, maximum.

Table 2.2-2
Mill Creek Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Boiler	Unit 1	1	CE subcritical, balanced draft boiler with reheater originally designed to fire high sulfur midwestern bituminous coal, at a main steam flow MCR of 2,326,000 lb/h at 2,600 psig and 1,005° F
	Unit 2	1	CE subcritical, balanced draft boiler with reheater originally designed to fire high sulfur midwestern bituminous coal, at a main steam flow MCR of 2,326,000 lb/h at 2,600 psig and 1,005° F
	Unit 3	1	B&W balanced draft, Carolina type radiant boiler with reheater, originally designed to fire high sulfur bituminous coal, at a main steam flow maximum continuous main rating of 3,144,000 lb/h at 2,600 psig and 1,005° F
	Unit 4	1	B&W balanced draft, Carolina type radiant boiler with reheater, originally designed to fire high sulfur bituminous coal, at a main steam flow maximum continuous main rating of 3,660,000 lb/h at 2,600 psig and 1,005° F
Steam Turbine	Unit 1	1	GE reheat tandem compound, double-flow turbine rated for nominal 2,400 psig 1,000° F steam, and hydrogen-cooled generator rated for 330 MW gross average
	Unit 2	1	GE reheat tandem compound, double-flow turbine rated for nominal 2,400 psig 1,000° F steam, and hydrogen-cooled generator rated for 330 MW gross average
	Unit 3	1	GE reheat tandem compound, double-flow turbine rated for 2,400 psig 1,000° F steam, with hydrogen-cooled generator rated for 423 MW gross average
	Unit 4	1	GE reheat tandem compound, double-flow turbine rated for 2,400 psig 1,000° F steam, with hydrogen-cooled generator rated for 521 MW gross average
Draft System	Unit 1	2	American Blower FD fans with Allis Chalmers 1,500 hp motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters (50 percent nom.)
		2	American Blower ID fans with fluid drives (50 percent nom.)
	Unit 2	2	American Blower FD fans with Allis Chalmers 1,500 hp motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters (50 percent nom.)
		2	American Blower ID fans with fluid drives (50 percent nom.)

Table 2.2-2 (Continued) Mill Creek Generating Station Major Equipment			
Description	Unit	Quantity	Characteristics
Draft System (Continued)	Unit 3	2	American Standard FD fans with 2,000 hp motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters (50 percent nom.)
		2	American Standard Blower ID fans with variable speed fluid drives (50 percent nom.)
	Unit 4	2	American Standard FD fans with 3,000 hp motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters (50 percent nom.)
		2	American Standard Blower ID fans with variable speed fluid drives (50 percent nom.)
Condenser	Unit 1	1	Two-pass vacuum condenser
	Unit 2	1	Two-pass vacuum condenser
	Unit 3	1	Two-pass vacuum condenser
	Unit 4	1	Two-pass vacuum condenser
Circulating Water System	Unit 1	1	Circulating water pump system
		1	Once-through cooling system, Ohio River
	Unit 2	1	Circulating water pump system
		1	Mechanical draft cooling tower; rectangular wooden type
	Unit 3	1	Circulating water pump system
		1	Mechanical draft cooling tower; circular concrete type
	Unit 4	1	Circulating water pump system
		1	Mechanical draft cooling tower; circular concrete type
Generator	Unit 1	1	GE, Serial 180X432, rated 356 MW, 22 kV, 500 volt excitation, H_2/water cooled, power factor 90 percent
	Unit 2	1	GE, Serial 180X525, rated 356 MW, 22 kV, 500 volt excitation, H_2/water cooled, power factor 90 percent
	Unit 3	1	GE, Serial 180X562, rated 463 MW, 22 kV, 500 volt excitation, H_2/water cooled, power factor 90 percent
	Unit 4	1	GE, Serial 180X747 544 MW, 22 kV, 500 volt excitation, H_2/water cooled, power factor 90 percent
Control Systems	Unit 1	1	Honeywell TDC-3000 and plant historian Honeywell PHD
	Unit 2	1	Honeywell TDC-3000 and plant historian Honeywell PHD
	Unit 3	1	Honeywell TDC-3000 and plant historian Honeywell PHD
	Unit 4	1	Honeywell TDC-3000 and plant historian Honeywell PHD

Table 2.2-2 (Continued) Mill Creek Generating Station Major Equipment			
Description	Unit	Quantity	Characteristics
Condensate and Feedwater Systems	Unit 1	3	Worthington, vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Allis Chalmers centrifugal, barrel, 5-stage, 5,400 rpm boiler feed pumps with Allis Chalmers motors rated at 6,500 hp and 1,784 rpm and variable speed fluid drives (50 percent nom.)
	Unit 2	3	Worthington, vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Allis Chalmers centrifugal, barrel, 5-stage, 5,400 rpm boiler feed pumps with Allis Chalmers motors rated at 6,500 hp and 1,784 rpm and variable speed fluid drives (50 percent nom.)
	Unit 3	3	Byron Jackson centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Centrifugal, barrel, multistage boiler feed pumps; one with motor drive and fluid coupling, one with steam turbine drive (50 percent nom.)
	Unit 4	3	Byron Jackson centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Centrifugal, barrel, multistage boiler feed pumps; one with motor drive and fluid coupling, one with steam turbine drive (50 percent nom.)
Flue Gas Treatment	Unit 1	1	Cold-side dry ESP for particulate matter (PM) removal Low NO_x burners, overfire air (OFA) and neural networks for NO_x reduction installed in 1996 Wet FGD system for 90 percent reduction of SO_2 installed in 1980
	Unit 2	1	Cold-side dry ESP for PM removal Low NO_x burners, OFA and neural networks for NO_x reduction installed in 1996 Wet FGD system for 90 percent reduction of SO_2 installed in 1980
	Unit 3	1	Cold-side dry ESP for PM removal Low NO_x burners and SCR for NO_x reduction installed in 2002 and 2003, respectively Wet FGD system for 90 percent reduction of SO_2 installed in 1982
	Unit 4	1	Cold-side dry ESP for PM removal Low NO_x burners and SCR for NO_x reduction installed in 2002 and 2004, respectively Wet FGD system for 90 percent reduction of SO_2 installed in 1982

Table 2.2-2 (Continued)
Mill Creek Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Electrical System	Unit 1	1	Westinghouse single-phase, voltage ratio ratings of 20.9 kV to 345 kV, 370/414.5 MVA, 55° C/65° C
	Unit 2	1	Westinghouse single-phase, voltage ratio ratings of 20.9 kV to 345 kV, 370/414.5 MVA, 55° C/65° C
	Unit 3	1	Westinghouse single-phase, voltage ratio ratings of 20.9 kV to 345 kV, 471/527 MVA, 55° C/65° C
	Unit 4	1	Westinghouse single-phase, voltage ratio ratings of 20.9 kV to 345 kV, 550/616 MVA, 55° C/65° C

The MC3 and MC4 turbines are GE reheat tandem compound, double-flow, rated for 2,400 psig 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator nameplate rating of 463 MW (Unit 3) and 544 MW (Unit 4), maximum.

Control Systems

The existing control systems for Mill Creek consist of Honeywell TDC-3000 PC-based systems. The plant historian is a Honeywell PHD model. There are plans to upgrade the MC2 burner management and soot blowers with computer hardware that has full Honeywell support. In addition, there is a proposed project to upgrade the cooling tower controls for MC3 and MC4 with hardware that is fully supported by Honeywell.

The plant has proposed other modifications to the controls, which include the replacement of the GE Mark II EHC controls with a new computer-based system for MC3 and MC4. This work will involve replacement of valve switches with triple-redundant low voltage differential transducers (LVDTs) and the interface to the distributed control system (DCS).

Emissions Systems

The emissions control systems on all four units include an ESP, FGD, and low NO_X burners for the removal of solids, SO_X, and NO_X. Additionally, MC3 and MC4 have an SCR for additional NO_X removal.

The MC1 and MC2 ESPs have four parallel cells with four mechanical sections in the flow path direction. The MC3 and MC4 ESPs have two parallel cells with four mechanical sections in the flow path direction. All units utilize an electromagnet rapping system to remove dust buildup on the collecting plate.

All units have a limestone-based FGD system that utilizes two countercurrent, open spray tower absorbers with a reaction slurry tank, slurry recirculation system, and in-situ forced oxidation. The operating permits governing the SO_2 emissions from each unit at the Mill Creek Station require the FGD systems to limit emissions to 1.2 pounds of SO_2 per MMBtu of heat input to the boilers, but actual emissions to meet emission allowances under the Acid Rain Program are significantly lower.

The MC3 and MC4 SCR systems are designed to reduce the outlet NO_x concentration by 90 percent and to meet all future emission targets that may be established in lieu of the recent vacating of CAIR. MC1 and MC2 do not have SCR systems for NO_x control. All units have low NO_x burners installed.

Extractive dilution type CEMS are installed on Units 1 through 4 for measuring NO_x, SO_2, CO_2, and stack flow. A particulate monitor is also installed in each stack to directly monitor PM emissions instead of opacity.

Auxiliary Systems

The station produces more than 1,250,000 tons of coal combustion and FGD byproducts annually. This includes 450,000 tons of fly ash, 120,000 tons of bottom ash, and 680,000 tons of gypsum per year. Fly ash is captured within ESPs and is either trucked to a cement plant or the onsite landfill. Bottom ash and mill pyrites are sluiced to the onsite ash pond. Gypsum is sluiced to the gypsum processing plant located on the southern area of the site. At the gypsum processing plant, the calcium sulfate byproduct of the FGD is filtered for shipment by barge to USG Gypsum, who takes up to 600,000 tons per year. This contract will terminate in the end of 2009, and the plant will have to look for other customers or send the gypsum to the ash pond. EON has plans to expand the existing landfill capacity horizontally for the 2008 through 2012 period, totaling approximately $9.7 millions. In addition, EON's other strategy for disposal of ash and FGD byproducts is to maximize off-site marketing. The target is to increase fly ash marketing by 100,000 tons per year into distant markets via railcar shipments.

The draft systems consist of two FD fans, two ID fans, and a Ljungstrom air heater. The boilers exhaust through ductwork to a 600 foot high flue stack.

All units use a single flue. MC1 and MC2 use a common chimney with separate flues for each unit. MC3 and MC4 each have a separate chimney. All units utilize a mechanical draft cooling tower for thermal cycle heat rejection, except MC1 which uses once-through cooling. A closed water circuit cooled by a common air-cooled heat exchanger provides auxiliary cooling.

MC1 and MC2 coal is pulverized by four CE 803 RS Raymond Bowl pulverizer mills. MC3 and MC4 coal is pulverized by four B&W MPS-89 Roll and Race mills.

Fuel Supply

Because of its location, Mill Creek Station is able to receive coal from both rail and river barge. Mill Creek Station is the only station in the LG&E/KU system able to receive coal both by barge and rail. However, the barge unloading system by itself does not have the capacity to meet the plant needs.

Limestone is received from barges unloaded at the river and stacked out in a storage yard located south of MC4.

Water and Wastewater

Raw water is withdrawn from the Ohio River from an intake structure. MC1 has a once-through cooling system, and this intake provides cooling for MC1 and raw water for the plant. The intake structure is treated regularly to control zebra mussels.

According to the spill prevention, control and countermeasure (SPCC) plan, three onsite groundwater supply wells were installed, but are not used. Drinking water is supplied by a municipal supplier.

Mill Creek Station does not have onsite sanitary sewage disposal. Sanitary sewage is sent offsite. Runoff from the coal pile area is collected and pumped to the ash pond (ash treatment basin).

Electrical and Interconnection

The electrical power output from MC1 thru MC4 is delivered from four generators each rated 22 kV, 90 PF. The four-unit station has a combined gross capacity of 1,628 MW. The electrical power is stepped up through GSU transformers to provide both load and voltage support for the 345 kV transmission systems.

The GSU transformers are the single-phase type connected in a three-phase configuration. The connection from the generators to their associated GSU transformers is by isolated phase bus duct. The 4.16 kV reserve auxiliary power for starting the units is derived from two reserve auxiliary transformers rated 13.8 kV-4.16 kV, 20/26/33 MVA OA/FA/FA. Normal operating power for auxiliary equipment is derived from dedicated main auxiliary transformers that are directly connected to the generator bus. MC1 and MC2 have one main auxiliary transformer each, while MC3 and MC4 have two main auxiliary transformers each. The reserve auxiliary transformers provide starting power to the unit and, after the unit has started, auxiliary power is derived through the main unit auxiliary transformers.

2.2.3 Performance

Table 2.2-3 shows the historical net generation, capacity factor, EAF, and EFOR for the Mill Creek Generating Station. The table also shows the industry averages for capacity factor, EAF, and EFOR. Industry average data come from GADS provided by the NERC and are for units in the SERC and RFC NERC regions and the years 2000 to 2006. The industry averages are as reported for units between 300 and 400 MW for Units 1 and Unit 2, between 350 and 550 MW for Unit 3, and between 450 and 650 MW for Unit 4.

In general, Mill Creek Generating Station average EAF and EFOR for the years 2004 to 2007 were comparable to industry averages. However, there were outage activities in the past 4 years that affected the EAF and EFOR of certain units. These events are listed below:

- In the spring of 2004, MC3 was down for the scheduled 2 month major steam turbine overhaul. The steam turbine was taken off-line again in fall of 2004 for 4 days to address a turbine bearing issue, which was resolved during the outage. MC3 reliability and vibration has been normal since the 2004 outage. MC3 also was taken off-line eight separate times in 2004 to repair several boiler tube leaks involving 2 weeks of planned outage work.

Table 2.2-3
Historical Performance Data for Mill Creek Generating Station Units 1 to 4

	2004	2005	2006	2007	Average
Unit 1					
Net Generation (MWh)	1,836,791	2,211,426	1,946,526	2,153,807	2,037,138
Net Heat Rate (Btu/kWh)	10,572	10,456	10,568	10,474	10,514
Capacity Factor (%)	69.2	83.3	74.0	81.1	76.9
Industry Average CF (%)					*52.2*
Equivalent Availability Factor (%)	84.5	94.9	86.5	92.2	89.5
Industry Average EAF (%)					*83.9*
Equivalent Forced Outage Rate (%)	5.6	3.7	4.4	3.7	4.4
Industry Average EFOR (%)					*6.7*

Table 2.2-3 (Continued)
Historical Performance Data for Mill Creek Generating Station Units 1 to 4

	2004	2005	2006	2007	Average
Unit 2					
Net Generation (MWh)	2,007,643	1,818,869	2,020,832	1,936,303	1,945,912
Net Heat Rate (Btu/kWh)	10,682	10,956	10,829	10,681	10,784
Capacity Factor (%)	76.4	69.2	76.9	73.7	74.0
Industry Average CF (%)					*52.2*
Equivalent Availability Factor (%)	92.5	81.0	90.5	85.7	87.4
Industry Average EAF (%)					*83.9*
Equivalent Forced Outage Rate (%)	4.3	6.8	4.5	3.9	4.9
Industry Average EFOR (%)					*6.7*
Unit 3					
Net Generation (MWh)	2,286,926	2,956,575	2,827,105	2,793,210	2,715,954
Net Heat Rate (Btu/kWh)	10,616	10,424	10,569	10,604	10,548
Capacity Factor (%)	66.2	85.6	81.9	80.9	78.6625
Industry Average CF (%)					*57.4*
Equivalent Availability Factor (%)	73.0	91.5	87.8	86.9	84.8
Industry Average EAF (%)					*83.5*
Equivalent Forced Outage Rate (%)	3.7	6.0	4.5	3.7	4.5
Industry Average EFOR (%)					*6.7*
Unit 4					
Net Generation (MWh)	3,405,217	3,077,144	2,938,797	3,565,,870	2,246,757
Net Heat Rate (Btu/kWh)	10,617	10,588	10,548	10,741	10,592
Capacity Factor (%)	80.2	72.5	69.2	84.1	76.5
Industry Average CF (%)					*65.2*
Equivalent Availability Factor (%)	90.4	79.3	69.0	90.8	82.4
Industry Average EAF (%)					*82.9*
Equivalent Forced Outage Rate (%)	3.7	17.6	4.5	4.4	7.6
Industry Average EFOR (%)					*4.7*

- In 2006, MC4 was down in early spring for the scheduled 2 month major steam turbine overhaul.
- In the summer of 2005, MC4 was taken off-line for a 6 week unplanned outage to rewind the generator rotor field and to replace a stator bar. The unit was also down in 2005 to repair boiler tube failures on nine separate occasions, accumulating more than 3 weeks of unplanned outage time.

Based on interviews with plant personnel and review of documentation provided, Black & Veatch understands that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget.

2.2.4 Operations and Maintenance

The operating plans and training materials provided outlined plans to ensure that the staff is familiar with station requirements and equipment. Recent efforts include updated system descriptions, pictures of the equipment, details regarding manufacturer and capabilities, as well as older material with little more than sequential steps to execute a particular task.

Mill Creek Station utilizes Maximo (a preventative maintenance program) for maintenance planning and management. This is consistent with the other EON units. The focus on the program is managing and improving both reliability and availability. There is also a boiler reliability program. This program is being implemented system-wide and appears to be a reasonably comprehensive program to identify issues compromising boiler reliability and operating costs, while at the same time, plan mitigation actions before issues become critical. The operating plan appropriately noted the concern that failure to implement specific boiler tube repair/replacement projects could compromise the plant's ability to meet EFOR targets.

It is Black & Veatch's understanding that Mill Creek Station uses the Maximo application to generate work orders using preventive maintenance schedules developed for the generating station's equipment and systems. Black & Veatch did not review any specific details or examples of preventive maintenance work orders.

The operating plans note the utilization of various predictive technologies. Specifically, the plans note the intent to utilize vibration monitoring/measurement, perform annual thermography inspections, biannual motor testing on all 4 kV motors, lubrication issues monitored through oil analysis, and the adjustment of PM schedules. The plan also calls for the addition of training on root cause analysis (RCA), problem solving, and procedure writing.

Black & Veatch reviewed the organization chart for the Mill Creek Station and noted a traditional organization. The total staff of approximately 220 is reasonable and consistent within the industry for the four Mill Creek Station units.

A specific individual was identified as the one dedicated to outage planning. The review of information regarding the outage maintenance practices noted that Mill Creek Station has incorporated the major elements of the corporate outage management program and is focused on meeting or exceeding target EFOR and EAF.

The operating plan calls for a 4 week outage every other year with a short (1 week) outage in the interim year and 8 week major outage. The frequency of the major outages was not specifically noted, but appears to be approximately a 7 year cycle. The plan also noted Mill Creek Station utilizes established joint procurement activities to support outages, including a pressure parts alliance agreement and a boiler craft labor agreement established for the EON fleet.

O&M Expenses

The historical operating costs for the Mill Creek Station are outlined in Table 2.2-4.

Table 2.2-4
Mill Creek Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$37,168	$39,218	$38,004	$43,890	$39,708
Other Cost of Services	$3,105	$3,720	$4,167	$4,265	$4,692
Fuel Handling	$4,539	$4,634	$4,604	$4,236	$5,148
Below the Line	$43	$114	$82	$85	$100
Total Controllable	$44,855	$47,686	$46,857	$52,476	$49,648
Net Generation (GWH)	9297	9536	10061	9751	10453
Controllable/MWh	$4.82	$5.00	$4.66	$5.38	$4.75

2.2.5 Equipment Condition

Black & Veatch personnel traveled to the Mill Creek facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the Plant on July 11 and 14, 2008. The generation facility appeared to be in good condition, with the exception of the back end ductwork and structural steel on Units 1, 2, and 4. Structural steel and ductwork in the scrubber areas of these units appeared to need inspection and corrosion protection or possible replacement soon because of corrosion.

The housekeeping and general facility condition in the FGD byproduct dewatering and handling area was greatly improved, compared to that seen in previous unrelated site visits, and should facilitate the continued operation of this facility.

In other areas, the quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition with no significant signs of significant leakage of oil, or steam, corrosion, or other distress. Some surface corrosion and several leaks in boiler bottom ash sluice systems, service water and circulating water piping, pump seals, and feedwater heater bottom drains in the basements were observed. However, these are not considered unusual considering the age of the plant.

Electrical rooms were clean and not used as storage for unrelated items. Battery rooms were locked and kept clean in general. The floor space in front of the switchgear was clear and open for operation. The control room and plant lighting was functioning. There was evidence of minor past transformer oil leaks on reserve auxiliary transformers (RAT) and GSU transformers, which is not considered unusual given the age of the equipment.

Boiler

In general, boiler tube leaks associated with fireside corrosion-induced tube wastage from reducing atmosphere at low NO_x burners, as well as slagging and erosion damage of convection areas, have been the main contributors to forced outage rates at the Mill Creek Station. This issue is also faced by some other coal fired stations of similar type and vintage in the industry. There has been persistent fretting of support tubes, and soot blower erosion problems are evident at Unit 3's primary superheater and superheater platen section.

EON plans to mitigate the tube leak problem by the implementing evaporator weld overlay projects for all four boilers and superheater/reheater upgrade projects on all four units. These extensive boiler tube replacements and upgrades planned by EON (to be completed by 2013 for a capital budget of $28 million) are aimed at helping reduce the tube leak rates and reduce plant EFOR.

Steam Turbines

Turbine major overhauls are generally scheduled every 7 years, and minor inspections are performed every 2 or 3 years. The last MC1 inspection was in 2004, and the next major overhaul is planned for 2010. MC1 was restarted at normal vibration levels (less than 3 mils) following the overhaul. Recommendations following the outage were to replace the 8th-stage buckets. The station currently plans to replace the MC1 HP/IP seals and turbine IP buckets in the 2010 major overhaul.

The last MC2 inspection was in 2003, and the next major overhaul is scheduled for 2011. When MC2 was returned to service, vibration levels were still high, but within acceptable limit to continue operation until the next overhaul. EON is monitoring the unit closely, and may need to perform a low-speed balance of the LP rotor at the next overhaul.

MC3 was last inspected in 2004, and the next major overhaul is scheduled for 2011. The unit was returned to service following the overhaul with no major deficiencies. A steam path audit was recommended for the next major overhaul; it was also recommended to address the unusual thrust bearing bump check characteristics of the unit and to monitor cracks on the HP/IP inner shells. EON plans to replace the HP/IP seals, the IP buckets, and to upgrade the turbine L-0 blades in 2011. The upgrade to the L-0 blades is expected to provide additional capacity of up to 30 MW with increased steam flow, or 1.9 MW at the same fuel input as the current levels.

MC4 was last inspected in 2006, and the next major overhaul is scheduled for 2014. The unit was returned to service following the overhaul with no major deficiencies. MC4 is currently experiencing slightly high vibration on the 3X bearing because of LP stator imbalance, as well as on the 9X bearing because of exciter vibration. EON is aware that these vibration levels are higher than normal, but are still within acceptable limits for continued operations and plans to resolve the problems at the next available opportunity. In addition, a longer-term plan to rewind the unit's generator rotor is also being considered in EON's capital plan.

Balance-of-Plant

The generation station complies with EON fleet standards for the use of predictive and preventive maintenance techniques for mill motors, mill gearboxes, and lubricating oil. This includes monthly vibration and oil analysis. Extensive mill upgrades were carried out for all units in 2003 to 2004, and several mill gearbox motors are planned for overhaul in the period 2008 to 2010. The typical overhaul period for MC3 and MC4 is 2 to 4 years for each mill. An average of more than $1,500,000 for mill annual inspection and repair is included in the 2009 to 2011 budget.

Flue gas ductwork for MC1, MC2, and MC4 near the FGD units was identified as one of the major concerns for the plant. Plant personnel explained that it has been discovered that the carbon steel ductwork has corroded behind the alloy duct linings. Several areas were observed where leaking flue gases were detected during plant walkdowns. Some of the flue gas ductwork insulation was missing and had been removed. Current capital plans include ductwork replacement for MC1, MC2, and MC4 as part of the FGD refurbishment projects that total $46 million for 2009 to 2012.

The station experiences significance forced outage due to condenser leaks and resulting high silica reading in cycle water chemistry. All of the condensers suffer from erosion damage at the inlet end. EON replaced the MC1 condenser tubes in 2004 with 90/10 copper nickel; however, occasional forced outages at MC1 still remain due to cycle chemistry silica issues and condenser leaks.

The station plans to replace the MC2 condenser tubes in 2011 at a cost of $1,900,000 as a long-term solution (tube inserts were installed in 1995). The MC3 condenser was found in fair condition in 2003. However, recently condenser problems in 2007 were second highest contributor to EFOR. EON plans to install condenser tube inserts in 2011. The MC4 condenser was recently fitted with condenser tube inserts in 2006.

It is expected that tube inserts will normally provide system enhancement for 5 to 10 years against additional erosion damage related outages. Therefore, it is expected that MC3 and MC4 will need to have tube replacement work scheduled accordingly.

The facility has experienced several plant derates in the past because of certain equipment failure in the reagent preparation system. EON's capital plan includes a $15 million budget for system upgrades to address this issue.

2.2.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.2. From information provided, the existing Mill Creek Station appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON submitted a 2007 Annual Air Compliance Certification indicating that it was in intermittent compliance with permit conditions. The report indicates that Method 5 stack tests were performed on the units, but testing reports were not submitted within the required period. In addition, monitoring of opacity and PM resulted in deviations of operating parameters caused by instrumentation or operational problems, but did not result in emission standard exceedances.

- A past problem with "rusty flake fallout" in the neighborhood was resolved with the addition of a wet stack conversion, according to EON.

Other

- Historically, according to the Environmental Protection Agency (EPA) ECHO database, the Mill Creek Station facility paid an Emergency Planning and Community Right-to-Know Act penalty of $19,500 in 2005. Information provided by EON indicated that EON had not reported anhydrous ammonia in the Mill Creek Toxic Release Inventory (TRI) report for calendar year 2003. The amount of ammonia onsite was above the reporting threshold. EON has resolved this issue in subsequent TRI reporting, in 2006 and 2007. No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of this information.
- The emissions issue for the station is the disposal of solid byproduct. It is Black & Veatch's understanding that EON is aware of this issue and steps to resolve the landfill needs of the station are already under way. EON has included the cost for expansion of the current landfill capacity in the projected capital budget and has obtained permits for expanding landfill capacity on the site..

2.2.7 Key Findings

- Mill Creek Generating Station appears to have the required environmental permits in place and to be operating in substantial compliance within permit and regulatory requirements.
- The facility is generally well positioned to meet current and future air emissions regulations. One environmental issue for the station is the disposal of solid byproduct. It is Black & Veatch's understanding that EON is aware of these issues and steps to resolve the landfill needs of the station are already underway. EON has included the cost for expansion of the current landfill capacity in the projected capital budget.
- The facility has experienced several plant derates in the past because of certain equipment failure in the reagent preparation system. EON's capital plan includes a $15 million budget for system upgrades to address this issue.
- The facility's boilers have experienced increased erosion, falling slag, corrosion fatigue, and heavy tube wastage. EON has allocated $28 million

in funding for boiler improvement and component replacement projects in its capital plan. The planned capital projects should help resolve the issues and improve future forced outage rates.

- The ductwork and structural steel near the FGD systems at Units 1, 2, and 4 appear to be nearing their useful lives. EON is aware of the problem and has budgeted for repair or replacement of these components in the planned FGD upgrade projects.
- There has been persistent fretting of support tubes, and soot blower erosion problems are evident at Unit 3's primary superheater and superheater platen section. Replacement of these components is estimated at $5,150,000. EON is aware of these problems and is looking at the possibility of allocating a budget to replace these components in the future.

2.3 Cane Run Generating Station

2.3.1 Introduction

The Cane Run Generating Station (Cane Run) is located at 5252 Cane Run Road (State Highway 1849), about 8 miles southwest of Louisville, Kentucky. The site location is illustrated on Figure 2.3-1. The facility includes approximately 500 acres between Cane Run Road and the Ohio River.

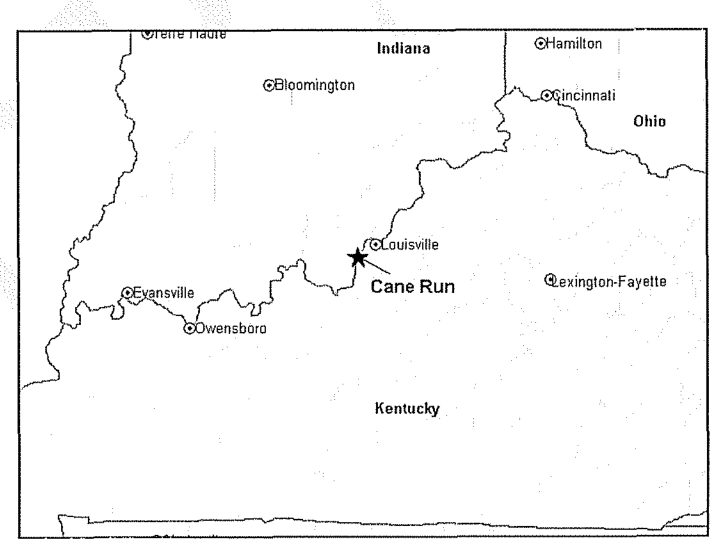

Figure 2.3-1
Cane Run Plant Location

The pulverized coal fired electric power plant began commercial operation in 1954 in response to the demand for electricity by industries that were located in Louisville during World War II. Three of its six units are now retired. Units 4 (CR4), 5 (CR5), and 6 (CR6) are currently active and have a gross capacity of 610 MW. CR4 was placed in service in 1962, CR5 in 1966, and CR6 in 1969. Table 2.3-1 provides a summary of the current Cane Run operating plant facts.

Table 2.3-1
Cane Run Plant Fact Sheet

Category	Data	Category	Data
Location:	Jefferson County, KY 8 miles southwest of Louisville	**Market Area:**	Midwest
Nominal Capacity:	563 MW net	**Off-Take:**	EON network customers
Ownership:	LG&E - 100%	**Electric Interconnection:**	Cane Run 138 kV Substation
Fuel:	Coal	**Fuel Supply:**	Contract and spot
Type:	Pulverized coal, subcritical fired steam generators	**COD:**	May 1, 1962 (Unit 4) May 1, 1966 (Unit 5) May 1, 1969 (Unit 6)
Equipment:	2 x CE boiler, 1 x Riley Stoker boiler, and 4 x GE steam turbines	**Operator:**	LG&E

Notes:
1. Nominal Capacity represents 100 percent of average (winter, summer) net electrical output,

The project is owned by LG&E, and its electrical interconnection is through the Cane Run 138 kV Substation. Units 4, 5, and 6 are designated as network resource generating units on the EON transmission system. The full load output from these units can be used to serve the network customers interconnected to the EON transmission system.

The Cane Run Station has historically burned high sulfur fuel from western Kentucky and Southern Indiana (Illinois Basin) at an average rate of 1.5 million tons of coal per year, all of which is transported by rail. Natural gas is used for startups of the coal fired boilers.

Most of the water serving the plant is withdrawn by an intake structure located in the Ohio River. The coal fired units utilize once-through cooling, so most of this water is returned to the river.

2.3.2 Plant Description and Design

Siting and Real Estate

Cane Run is located at 5252 Cane Run Road (State Highway 1849), about 8 miles southwest of Louisville, Kentucky. The facility includes approximately 500 acres between Cane Run Road and the Ohio River. An aerial view of the facility is shown on Figure 2.3-2.

The entrance road is straight and parallels the railroad and power lines. The road will be scheduled to be relocated when plans for a new landfill area are determined.

Equipment

The gross plant steam generating capacity is 610 MW and consists of three active coal fired units (CR4, CR5, and CR6), having current gross capacity ratings of approximately 168 MW, 181 MW, and 261 MW, respectively. The major plant equipment is listed in Table 2.3-2.

Boilers

Both CR4 and CR6 have CE boilers. CR4's boiler is a wall fired, balanced draft boiler with reheater, originally designed to fire high sulfur bituminous coal, rated for 1,200,000 lb/h of steam at 1,900 psig and 1005° F. CR6's boiler is a tangential-fired, balanced draft boiler with reheater, originally designed to fire high sulfur bituminous coal, rated for 1,854,000 lb/h of steam at 2,600 psig and 1,005° F.

CR5 has a Riley Stoker wall fired, balanced draft boiler with reheater, originally designed to fire high sulfur western Kentucky bituminous coal, rated for 1,360,000 lb/h of steam at 1,900 psig and 1,005° F.

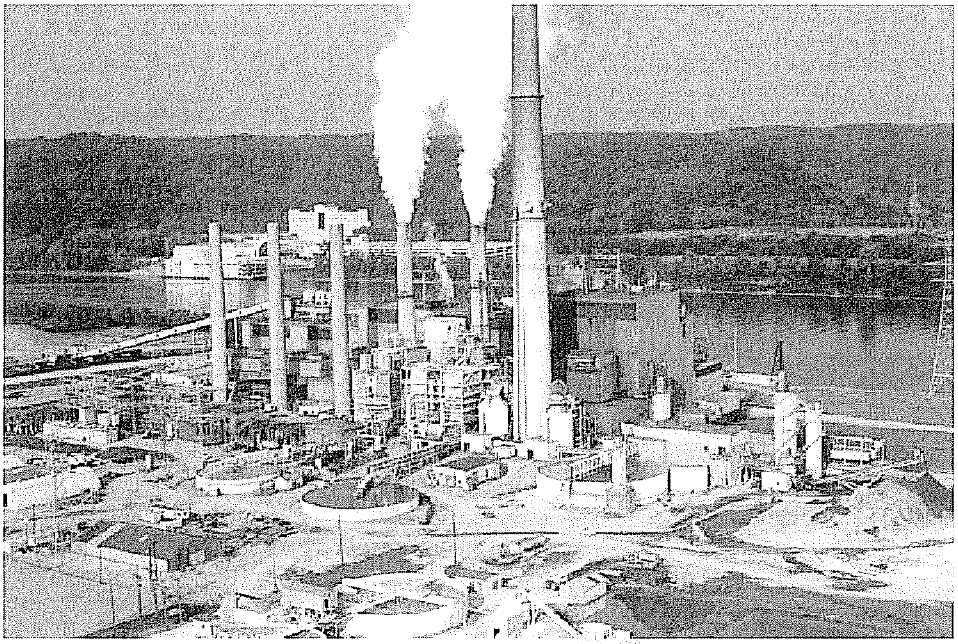

Figure 2.3-2
Cane Run Generating Station

Table 2.3-2
Cane Run Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Boiler	Unit 4	1	CE wall fired, balanced draft boiler with reheater, originally designed to fire high sulfur bituminous coal, rated for 1,200,000 lb/h of steam at 1,900 psig and 1005° F
	Unit 5	1	Riley Stoker wall fired, balanced draft boiler with reheater, originally designed to fire high sulfur western Kentucky bituminous coal, rated for 1,360,000 lb/h of steam at 1,900 psig and 1,005° F
	Unit 6	1	CE tangential-fired, balanced draft boiler with reheater, originally designed to fire high sulfur bituminous coal, rated for 1,854,000 lb/h of steam at 2,600 psig and 1,005° F
Steam Turbine	Unit 4	1	GE reheat tandem compound, double-flow turbine, rated for 1,910 psig 1000° F steam, and hydrogen-cooled generator rated for 168 MW gross average
	Unit 5	1	GE reheat tandem compound, double-flow LP turbine, rated for 1,800 psig 1,000° F steam, and hydrogen-cooled-generator rated for 181 MW gross average
	Unit 6	1	Westinghouse reheat tandem compound, double-flow LP turbine, rated for 2,400 psig 1,000° F steam, and hydrogen cooled generator rated for 261 MW gross avg
Draft System	Unit 4	2	Buffalo Forge FD fans with fluid drives and 700 hp Allis Chalmers motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, air heaters (50 percent nom.)
		2	Buffalo ID fans with variable speed drives (50 percent nom.)
	Unit 5	2	Westinghouse FD fans with Gyrol VS fluid drives and 800 hp Westinghouse motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, air heaters (50 percent nom.)
		2	Westinghouse ID fans with Gyrol VS fluid drives and 1,750 hp Westinghouse motors (50 percent nom.)
	Unit 6	2	Westinghouse FD fans with inlet vane control and 1,250 hp GE motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, air heaters (50 percent nom.)
		2	Westinghouse ID fans with Gyrol fluid drives and 2,000 hp GE motors (50 percent nom.)

Table 2.3-2 (Continued)
Cane Run Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Condenser	Unit 4	1	Two-pass vacuum condenser
	Unit 5	1	Two-pass vacuum condenser
	Unit 6	1	Two-pass vacuum condenser
Circulating Water System	Unit 4	2	Circulating water pumps (50 percent nom.)
		1	Once-through cooling system, Ohio River
	Unit 5	2	Circulating water pumps (50 percent nom.)
		1	Once-through cooling system, Ohio River
	Unit 6	2	Circulating water pumps (50 percent nom.)
		1	Once-through cooling system, Ohio River
Generator	Unit 4	1	GE 192 MVA, 3 phase, 2-pole, 18 kV, 0.85PF, hydrogen-cooled
	Unit 5	1	GE 224 MVA, 2-pole, 3-phase, 0.85 PF, 22 kV, hydrogen-cooled
	Unit 6	1	Westinghouse 320 MVA, 3-phase, 2-pole, 22 kV, 0.85 PF, hydrogen-cooled
Control Systems	Unit 4	1	Honeywell Experion
	Unit 5	1	Honeywell Experion
	Unit 6	1	Honeywell Experion
Condensate and Feedwater Systems	Unit 4	3	Byron Jackson vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Allis-Chalmers centrifugal, barrel, multistage boiler feed pumps with 2,500 hp electric motors and American Standard fluid drives (50 percent nom.)
	Unit 5	3	Westinghouse vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Allis-Chalmers centrifugal, barrel, multistage boiler feed pumps with, 3,000 hp electric motors and American Standard fluid drives (50 percent nom.)
	Unit 6	3	Ingersoll-Rand vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Allis-Chalmers centrifugal, barrel, multistage boiler feed pumps with GE 5,500 hp electric motors and American Standard fluid drives (50 percent nom.)

Table 2.3-2 (Continued)
Cane Run Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Flue Gas Treatment	Unit 4	1	Cold-side dry ESP for PM removal Lime-based, FGD system retrofitted in 1976 by American Air Filter NO_x burner combustion controls retrofit in 2003
	Unit 5	1	Cold-side dry ESP for PM removal Lime-based, FGD system retrofitted in 1976 by AAF NO_x burner combustion controls retrofit in 2003
	Unit 6	1	Cold-side dry ESP for PM removal Dual alkali based FGD system retrofitted in 1979 by Combustion Equipment Associates NO_x burner combustion controls retrofit in 1995
Electrical System	Unit 4	1	Westinghouse 18 kV-138 kV, 190 MVA
	Unit 5	1	Westinghouse 18 kV-138 kV, 220/240 MVA
	Unit 6	1	Westinghouse 20.9 kV-138 kV, 320 MVA

Steam Turbine Generators

Both CR5 and CR6 have reheat tandem compound, double-flow type LP turbines. CR5 is a GE unit rated for 1,800 psig 1,000° F steam, and includes a two-pass condenser and hydrogen-cooled generator rated for 181 MW. CR6 is a Westinghouse unit rated for 2,400 psig 1,000° F steam, and comes with a two-pass condenser and hydrogen-cooled generator rated for 261 MW.

CR4 has a GE reheat tandem compound, double-flow turbine rated for 1,910 psig 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 168 MW.

Control Systems

The control systems at Cane Run have been upgraded over the years from the original Bailey and GE systems to the Honeywell TDC-3000 Experion platform.

Extensive control upgrades to the Woods Group system are planned for the turbine controls for CR4 and CR5. This upgrade was recently performed on CR6.

The coal handling system controls will have a $550,000 upgrade in 2012, and the water treatment system controls have a $75,000 replacement scheduled for 2013. The CR6 burner management system controls will be replaced for $290,000 in 2013.

Emissions Systems

All three coal fired units are equipped with low NO_x burners, FGD modules, ESPs, and CEMS.

The low NO_x burner for CR4 is a Foster Wheeler (FW) model that was installed in 1998. CR5's low NO_x burner is from Riley (installed in 1994), and CR6's burner is from CE (installed in 1997).

The FGD modules remove SO_2 from the boiler flue gases by contact with lime slurry (calcium oxide slaked with water). Units CR4 and CR5 have lime-based FGD systems that utilize two countercurrent, open-spray tower absorbers with a common reaction slurry tank and slurry recirculation system. The Unit 6 FGD is one of two dual-alkali scrubbers still operating in the United States, consisting of separated scrubber loops, with two main reagents (lime and soda ash). Soda ash liquor is pumped onto liquid trays in the two absorbers where the solution removes SO_2 from the flue gas. Lime is then used to regenerate the sodium.

Each Cane Run active unit has a cold side ESP with collecting plates, an electromagnet rapping system to remove dust buildup on the collecting plate surfaces, and discharge electrodes.

Extractive dilution type CEMS are installed on all units for measuring NO_x, SO_2, CO_2, and stack flow. A continuous opacity monitor is also installed downstream of the ESPs and ahead of the FGD to monitor opacity. The CEMS software has been upgraded to StackVision, the latest programming available from ESC, a data acquisition and handling system OEM. This latest software upgrade should allow the station to meet future reporting requirements by the EPA or state agencies.

Auxiliary Systems

The bottom ash is collected in water filled hoppers, or ash pits, located directly below the furnaces, at the bottom each of the boilers. The bottom ash is disintegrated and cooled upon contact with the water in the hoppers. The hoppers are emptied by jet propulsion pumps that transport the bottom ash through a discharge line to the ash pond. CR4 has one water filled bottom ash hopper, Unit 5 and 6 each have two water filled bottom ash hoppers.

The pyrite systems on CR4, CR5 and CR6 transport rejects from the coal mills to the pyrite storage tank. Each coal mill has an individual pyrite hopper, jet propulsion pump, and transport line. The pyrite sluice conveying system is designed to convey pyrites from each units pyrite hoppers to a pyrite storage/transfer tank. From the pyrite storage tank, the ash is pumped to the ash pond.

Precipitator hoppers are located beneath the ESPs. This is the final removal area before the boiler flue gas is exhausted to the scrubbers. Fly ash from the precipitator hoppers is conveyed in a dry state when saving fly ash to the north bin and in a wet state when sluicing fly ash to the ash pond.

CR4 has two economizer hoppers, CR5 has 6 economizer hoppers, and CR6 has four economizer hoppers. CR4 economizer hoppers are located on the back side of the boiler on the main floor; CR5 economizer hoppers are located at the mezzanine level, and CR6 economizer hoppers are located on the third floor on the back side of the boiler. In addition to the economizer hoppers, CR6 has four duct hoppers located in the flue gas inlet ductwork to the regenerative air preheaters with two hoppers on each side. The duct hoppers are located on the CR6 mezzanine floor. The fly ash on all the economizer hoppers and the CR6 duct hoppers are transported to the ash pond.

The station has an ash water system that provides the water flow and pressure necessary to transport the bottom ash and top ash to their designated storage or disposal areas. The ash water system consists of four ash water pumps with piping and valves necessary to transport the HP water to the designated systems.

Fuel Supply

Cane Run has historically burned a high sulfur fuel from western Kentucky and southern Indiana (Illinois Basin) at an average rate of 1.5 million tons of coal per year, all of which is received at the station by railcar. The rail line has ladder sidings to stage the coal cars for unloading (it is not a loop rail system). Once the coal is transported by rail to the stations ladder rail siding, it is unloaded from the bottom dump railcars on top of the unloading hopper. The conveyor system takes the coal either to the storage pile or to the crushers; it is then conveyed to the in-plant coal bunkers.

Water and Wastewater

Most of the water serving the plant is withdrawn by an intake structure located in the Ohio River. The coal fired units utilize once-through cooling, so most of this water is returned to the river. Drinking water is supplied by a municipal system.

Electrical and Interconnection

The station is interconnected to the EON 138 kV transmission system via the Cane Run 138 kV Substation. The electrical power output of the units is delivered from unit-dedicated generators and stepped up by GSU transformers to the 138 kV voltage level. The connections from the generators to the respective GSU transformers are by isolated phase bus ducts. The station has a 4.16 kV distribution system that is common across the plant.

2.3.3 Performance

Table 2.3-3 shows the historical net generation, capacity factor, EAF, and EFOR for the Cane Run Generating Station. The table also shows the industry averages for capacity factor, EAF, and EFOR. Industry average data come from GADS provided by the NERC and are for units in the SERC and RFC NERC regions and the years 2000 to 2006. The industry averages are as reported for units between 150 and 200 MW for Unit 4, between 160 and 260 MW for Unit 5, and between 200 and 350 MW for Unit 6.

In general, Cane Run Generating Station average EAF and EFOR for the years 2004 to 2007 were comparable to industry averages. However, there were outage activities in the past 4 years that affected the EAF and EFOR of certain units. These events are listed below:

- In 2004, CR4 was down for the scheduled 2 month major steam turbine overhaul. The unit was also taken off-line separately for several days to perform scheduled maintenance for the air heater, to address furnace tube leaks, and to repair FGD recycle pumps.
- In 2004, CR5 was down for the pulverizer mills upgrade project that lasted approximately 2 months. The unit was also taken off-line for several days to perform scheduled maintenance for boiler tube leaks, air heater fouling, and FGD demister repair.
- In 2004, CR5 experienced a number of forced outage events related to boiler tube leaks and ID fans. The ID fan reliability has improved since 2004.
- In 2007, CR5 experienced a number of forced outage events related to boiler tube leaks. Boiler tube replacement projects are included in the planning period of 2008 to 2012 to improve boiler reliability.
- In 2005, CR6 experienced a high number of forced outage events related to boiler tube leaks.

Table 2.3-3
Historical Performance Data For Cane Run Generating Station Units 4, 5, and 6

	2004	2005	2006	2007	Average
Unit 4					
Net Generation (MWh)	810,896	1,049,049	959,912	1,102,772	980,657
Net Heat Rate (Btu/kWh)	11,132	10,898	10,608	10,876	10,869
Capacity Factor (%)	59.7	77.3	70.7	81.2	72.2
Industry Average CF (%)					*63.2*
Equivalent Availability Factor (%)	77.0	89.0	85.9	93.6	86.4
Industry Average EAF (%)					*86.3*
Equivalent Forced Outage Rate (%)	5.9	7.3	4.8	2.7	5.2
Industry Average EFOR (%)					*6.0*
Unit 5					
Net Generation (MWh)	894,036	1,087,989	1,086,066	1,041,442	1,027,383
Net Heat Rate (Btu/kWh)	10,889	10,524	11,064	11,227	10,924
Capacity Factor (%)	60.8	73.9	73.8	70.8	69.8
Industry Average CF (%)					*62.5*
Equivalent Availability Factor (%)	76.0	89.2	84.9	84.7	83.7
Industry Average EAF (%)					*84.8*
Equivalent Forced Outage Rate (%)	9.7	3.2	4.8	8.4	6.5
Industry Average EFOR (%)					*6.2*
Unit 6					
Net Generation (MWh)	1,508,847	1,537,931	1,529,165	1,392,397	1,492,085
Net Heat Rate (Btu/kWh)	10,387	10,235	10,569	10,556	10,434
Capacity Factor (%)	71.8	73.2	72.7	66.2	71.0
Industry Average CF (%)					*64.4*
Equivalent Availability Factor (%)	89.9	84.2	85.6	76.7	84.1
Industry Average EAF (%)					*85.0*
Equivalent Forced Outage Rate (%)	4.0	7.4	4.8	13.2	7.4
Industry Average EFOR (%)					*5.9*

- In the spring of 2007, CR6 was down for the scheduled annual 3 week boiler inspection and subsequently was taken off-line again in the fall to repair leaks on the steam turbine hydrogen cooler gaskets and diaphragms. In addition, T-2, T-3, and T-4 bearings were reconditioned in 2007 due to partial wipes and excessive heating. The CR6 T-2, T-3, and T-4 bearings have been operating at normal vibration since they were reconditioned, but CR6 suffers from high subsynchronous vibration at the No. 1 bearing that prevents prolonged operation in the range of 60 to 85 percent of full load.
- In 2007, CR6 experienced a boiler wind box fire (September 2007, 10 day unplanned outage), as well as forced outage events related to boiler tube leaks and reheater slagging/fouling. An RCA of the fire was not provided for review. Temporary repairs were made, but the burner is reported to be operating below design level, the tilting mechanism does not function, and there is significant combustion air leakage. Cane Run Station reported that the existing design is no longer available from the OEM, and the current air flow design will need to be modified in the other three corners once this corner is replaced. The current EON plan includes replacing CR6 burner corner Number 4 in 2009, as well as design changes to the air control for the remaining three burners. Boiler tube projects are also included in the planning period from 2008 to 2012 to improve boiler reliability.

Based on interviews with plant personnel and review of documentation provided, except as otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget.

2.3.4 Operations and Maintenance

The Black & Veatch assessment team reviewed the organization charts, discussed the staffing organization with EON staff, and reviewed the operating plan for Cane Run. Specific issues noted in this review include the organization of the operations group (shift workers) into four separate operating groups, the dedicated outage coordinator, and the two planning positions in the maintenance organization. The use of four operating groups is a common and recommended practice to address the challenges of covering round-the-clock operations, while also maintaining a cohesive "team" of operators. Black & Veatch noted the dedicated outage coordinator, specifically identified on the organization chart as a recommended practice to ensure that outage activities are adequately planned and given the appropriate priority.

Daily planning requirements are fulfilled by two planners noted on the organization chart. One planner has responsibility for mechanical maintenance, and the other is focused on Instrument and Electrical (I/E) processes. Given the number of units and the fact that all three units have wet scrubbers, using two planners may not be adequate, especially in light of the need to support steam unit outages as well as hydro and CT activities.

The operations plan noted that the plant is utilizing and developing multi-skilled employee groups to improve overall productivity. This program included combining the plant and yard operating groups at Cane Run and providing operators to assist with specific maintenance tasks at Ohio Falls Hydro. This practice can be a challenge to administer with respect to labor relations but, in practice, tends to improve overall productivity and broaden employees' perspective and appreciation for the skills of the "other" work groups.

Documents provided indicated that a comprehensive program for station helpers includes initial qualification, continuous reassessment, and refresher training. The documents included extensive details regarding plant systems, as well as general or introductory training programs to ensure that students are well versed in fundamentals.

The operating plan also noted that the plant management is participating in development training over and above the technical training offered to operators and/or craft persons.

Cane Run, like all the other EON assets utilizes the Maximo CMMS application for maintenance planning and associated work management functions. The Cane Run helper training materials specifically require the demonstration of knowledge regarding the maintenance work order system. Can Run also utilizes Oracle Materials for managing warehouse materials and Oracle Financials for budget management.

Black & Veatch understands that the station utilizes the Maximo work management processes and work order systems to implement both the preventive maintenance activities and the PDM tasks. The operating plan noted efforts to review the preventive maintenance routines to implement streamlined routine corrective maintenance (RCM). The operating plan outlined an extensive program to monitor and address the sources/causes of tube leaks throughout the boilers, with specific details regarding and distinguishing each boiler. This program, which is being implemented across the EON fleet, is referred to as the "Boiler Circuit Strategy." The program appears to be a comprehensive program to identify and manage the reliability of the boilers.

The operating plan included an effort to continue to develop the formal PDM program. Specific activities noted included implementation of a motor monitoring program and use of infrared cameras to troubleshoot electrical equipment.

With respect to the outage management process, Cane Run has incorporated the major elements of the corporate program, including the designation of a dedicated outage coordinator whose sole responsibility is outage planning. From the information provided, it would appear the outage and overhaul strategies are consistent with prudent management practices. The plan calls for annual 3 week boiler/auxiliary outages and turbine outages on a 7 year cycle. The turbine outages are expected to require an 8 week outage.

O&M Expenses

The historical operating costs for Cane Run are outlined in Table 2.3-4. These operating costs are those associated only with CR4, CR5, and CR6.

Table 2.3-4
Cane Run Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$32,962	$26,561	$25,687	$31,492	$27,002
Other Cost of Services	$0	$7,265	$9,028	$9,169	$11,694
Fuel Handling	$1,094	$1,022	$1,192	$1,282	$1,210
Below the Line	$23	$45	$34	$21	$9
Total Controllable	$34,079	$34,893	$35,941	$41,964	$39,915
Net Generation (GWH)	3544	3214	3676	3576	3537
Controllable/MWh	$9.61	$10.86	$9.78	$11.73	$11.28

The details of the Cane Run operating costs are shown in Appendix B.

2.3.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the plant on July 23, 2008. The plant facility appeared to be in good condition. The quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil, or steam, corrosion damage, or other distress, except for structural steel and duct degradation that has occurred in the FGD-related facilities.

The operation in the landfill area creates dust because much of the area is still uncapped, and the byproduct is exposed. The bunker room dust collectors did not appear to be adequate based on the observed coal dust accumulations. EON is aware of these issues and is working to resolve them.

The recently upgraded coal mills on CR5 were noted to be in excellent condition. Some surface corrosion and several water leaks were observed near the boiler bottom ash sluice systems and cycle makeup water areas; however, these are not considered unusual considering the age of the plant. The boiler feed pump seals were in good condition; no leaks or oil spills were observed. The boiler feed pumps have clearly been professionally maintained.

Electrical rooms were clean and not used as storage for unrelated items. Battery rooms were locked and kept clean in general. The floor space in front of the switchgear was clear and open for operation. The control room and plant lighting was functioning. Some minor degradation of the plant building roof was observed that may require some repairs in the future. However, the degradation of the building roof is not considered unusual considering the age of facility.

Boilers

Boiler tube leaks have been the main contributor to forced outage rates at the station. This is considered a common problem faced by many other coal fired stations of similar type and vintage in the industry. The station performs internal inspection and testing of each boiler every 12 to 18 months during planned outages. EON recognizes this problem and plans to increase the O&M budget as part of the boiler circuit strategy for this station. For the 2008 to 2012 planning period, the O&M budget will average approximately $5,650,000 per year for outage work (including steam turbines). This represents an increase of $3,400,000 per year for the same activities over the last 7 years. EON has also identified $26 million capital for boiler tube component replacement and improvement projects scheduled for the 2008 to 2012 planning period.

Steam Turbines

Turbine inspections are generally scheduled every 7 years. The CR4 steam turbine has more than 243,000 hours of operation as of June 2008. CR4 steam turbine last underwent major outage in 2004. The unit presently experiences higher than normal vibration at Bearings 4, 7, and 8. The higher than normal vibration levels at Bearings 7 and 8 are due to a gear box issue. EON is monitoring the vibration levels closely and is planning to perform trim balance shots at the next available opportunity. The next turbine overhaul is scheduled for 2011, at which time EON plans to replace the HP first-stage buckets and to replace the turbine packing and seals.

The CR5 steam turbine has more than 274,000 hours of operation as of June 2008. CR5 steam turbine underwent an 8 week inspection overhaul in 2008, led by turbine contractor, MD&A. The unit was returned to service following high-speed balance of the generator, with higher than normal vibration levels (3.7 mils) at Bearing 6. A recent repair performed due to generator collector ring brush failure has caused further increase in the vibration levels to 4.8 mils. EON is monitoring the vibration levels closely and is planning to resolve the vibration issue at the next available opportunity. The next CR5 major turbine outage is scheduled for 2014 to 2015.

The CR6 steam turbine has more than 243,000 hours of operation as of June 2008. The CR6 turbine overhaul is due in 2009. CR6 experiences high subsynchronous vibration that prevents operation in the range of 60 to 85 percent of full load. Capital projects to address these issues should be added where this cannot be covered by the O&M budget.

Balance-of-Plant

The ash pond is nearing capacity and has approximately 1 to 2 years of useful life remaining. The identified solution is to reclaim bottom ash material (pyrite) from the pond for beneficial reuse or for placement in the special waste landfill onsite to allow continued use of the current ash pond without the need to increase capacity.

The current landfill vertical expansion project provides capacity until approximately 2013. The vertical expansion of the landfill requires staged infrastructure improvements (e.g., permanent drainage structures and drains) to facilitate growth and closure. These are capital improvements and will occur with the expansion over time. The planned annual expenditures associated with such capital improvements appear to be reasonable.

2.3.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.3. From the information provided, the existing Cane Run Station appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON submitted a 2007 Annual Air Compliance Certification indicating that it was in intermittent compliance with permit conditions. The report indicated that several units deviated from their permit requirements. These deviations included the following issues:
  - Method 5 stack tests were performed on units, but testing reports were not submitted within the required period.
  - SO_2 excess emissions and reporting.
  - Opacity standard and conducting Method 9 tests.
  - Compliance with reporting requirements.

  The report indicated that these intermittent compliance issues were previously reported in semiannual reports or the quarterly Title V monitoring summary reports, quarterly excess emission reports, or upset condition reports.

Other

- As Black & Veatch observed during the site visit, adequate long-term options for disposal and storage of combustion products is an important consideration for Cane Run. The bottom ash pond has 1 to 2 years of remaining capacity, and the landfill for disposal of FGD byproduct and fly ash has 4 to 5 years of capacity. While plans to alleviate this problem are being developed through the potential permitting of additional specific onsite disposal sites, these plans are not finalized and can be subject to regulatory and public scrutiny. Cane Run is trying to find beneficial use opportunities for the combustion products to help alleviate the issue.

2.3.7 Key Findings

- Cane Run appears to have the required environmental permits in place and to be operating in substantial compliance with permit and regulatory requirements.
- In general, some portions of the facility's FGD systems appear to be nearing the end of their useful life. EON is currently looking at extending the facility's FGD useful life by another 20 years. An extensive engineering study has been performed recently (by a third party consultant), which will be used to evaluate capital projects in the near future for this work.

- The bottom ash pond at the facility appears to have 1 to 2 years of remaining capacity, and the landfill for disposal of FGD byproduct and fly ash appears to have approximately 4 to 5 years of remaining capacity. Plans to alleviate this problem are being developed through the potential permitting of additional specific onsite disposal sites. In addition, EON is trying to find beneficial use opportunities for the combustion products to help alleviate the issue.
- Boiler tube failures have been identified as the root cause for most of the forced outage events at the station. EON has identified approximately $26 million worth of capital improvement projects for the planning period from 2008 to 2012 to address the problem.

2.4 Ghent Generating Station

2.4.1 Introduction

The Ghent Generating Station (Ghent) is located approximately 9 miles northeast of Carrolton, Kentucky. The site location is illustrated on Figure 2.4-1. Ghent, which began commercial operations in February 1, 1974, is situated on approximately 1,670 acres.

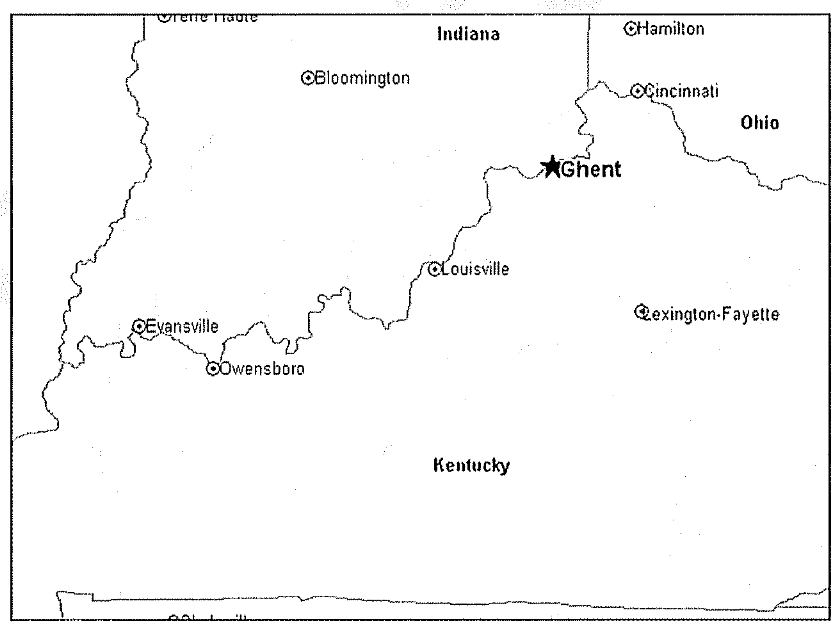

Figure 2.4-1
Ghent Site Location

The plant is a pulverized coal fired electric power plant with a nameplate capacity of 2,000 MW. It comprises four units (GH1, GH2, GH3, and GH4), each with boilers and steam turbines. Two of the boilers are manufactured by CE and two by FW. CE boilers are tangential-fired, balanced draft forced circulation boilers, and FW boilers are balanced draft natural circulation boilers. Three of the steam turbines are manufactured by GE and one by Westinghouse. They are all reheat, double-flow steam turbines with hydrogen-cooled generators. Table 2.4-1 provides a summary of the Ghent plant facts.

The project is owned by KU (100 percent). Ghent is designated as a network resource generating unit on the EON transmission system. The full load output from this unit can be used to serve the network customers interconnected to the EON transmission system.

Ghent's electrical interconnection is with Duke Energy Shared Services, Inc., with 138 kV and 345 kV transmission lines at the Kentucky state line using the Northside Substation near Sellersburg, Indiana, and the Beargrass Substation in Louisville, Kentucky.

Ghent burns high and low sulfur coal delivered by barge tow. The coal is supplied by Nally and Hamilton Enterprises and Coal Sales, LLC.

2.4.2 Plant Description and Design

Siting and Real Estate

Ghent is located on the Ohio River between Cincinnati and Louisville, just northeast of Carrolton, Kentucky. US Highway 42 runs immediately in front of the power station. The highway divides the generating facilities from the switchyard, ash ponds, gypsum pond and stack out facility, and the ammonia storage facility, all located on the south side of the highway. The generation units and coal yard are on the north side of the highway; the ash pond and gypsum handling areas are on the south side of the highway. Figure 2.4-2 illustrates the plant and neighboring real estate.

There is a railway line that also runs adjacent to US Highway 42. The plant, however, does not receive any coal or other consumable products by rail. The railway line is only used occasionally for deliveries of major equipment.

Equipment

Ghent is a 2,000 MW plant that is composed of four 500 MW (nominal capacity), coal fired and steam turbine generators. The major plant equipment is listed in Table 2.4-2.

Table 2.4-1
Ghent Generating Station Fact Sheet

Category	Data	Category	Data
Location:	Carrolton, KY	**Market Area:**	Midwest
Nominal Capacity:	1921.5 MW net	**Off-Take:**	EON network customers
Ownership:	KU - 100 %	**Electric Interconnection:**	Ghent 138 kV (Unit 1) and 345 kV (Units 2,3,4) Substations
Fuel:	Coal	**Fuel Supply:**	Contract and spot
Type:	Pulverized coal, subcritical fired steam generators	**COD:**	February 1, 1974 (Unit 1) April 1, 1977 (Unit 2) May 1, 1981 (Unit 3) August 1, 1984 (Unit 4)
Equipment:	2 x CE boilers, 2 x FW boilers, 1 x Westinghouse steam turbine and 3 x GE steam turbines	**Operator:**	KU

Notes:
1. Nominal Capacity represents 100 percent of average (winter, summer) net electrical output.

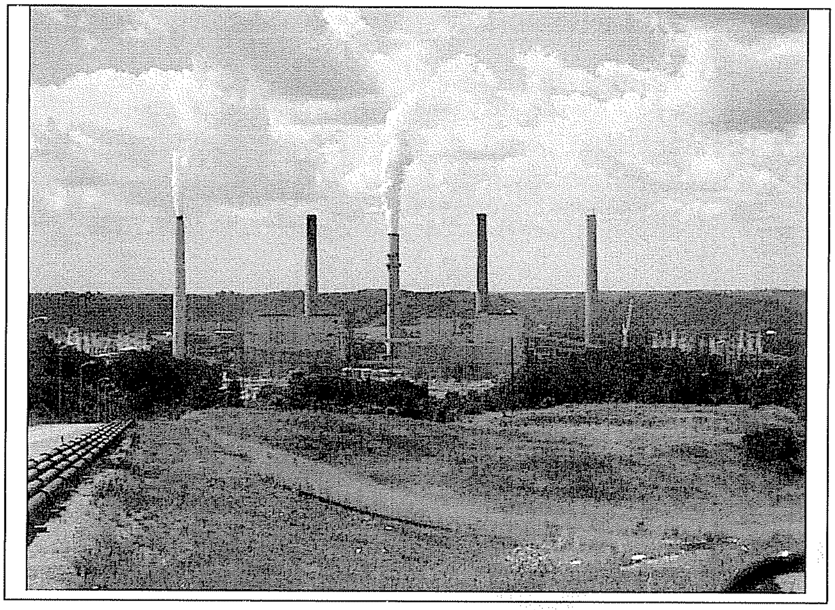

Figure 2.4-2
Ghent Generating Station

Table 2.4-2
Ghent Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Boiler	Unit 1	1	CE subcritical, controlled circulation, balanced draft boiler with reheater, originally designed to fire high sulfur Muhlenberg KY bituminous coal, at main steam flow MCR of 3,800,000 lb/h at 2,620 psig and 1,005° F
	Unit 2	1	CE subcritical, controlled circulation, balanced draft boiler with reheater originally designed to fire high sulfur western Kentucky or low sulfur eastern Kentucky bituminous coal, at main steam flow maximum continuous main rating of 3,800,000 lb/h at 2,620 psig and 1,005° F
	Unit 3	1	FW subcritical, natural circulation, balanced draft boiler with reheater, originally designed to fire low sulfur eastern Kentucky bituminous and alternate low-Btu, low sulfur western USA coal, at main steam flow maximum continuous main rating of 3,800,000 lb/h at 2,620 psig and 1,005 F
	Unit 4	1	FW subcritical, natural circulation, balanced draft boiler with reheater, originally designed to fire low sulfur eastern Kentucky bituminous and alternate low-Btu, low sulfur western USA coal, at main steam flow maximum continuous main rating of 3,800,000 lb/h at 2,620 psig and 1,005 F
Steam Turbine	Unit 1	1	Westinghouse reheat tandem compound, double-flow turbine rated for nominal 2,400 psig 1,000° F steam, with condenser and hydrogen-cooled generator rated for 515 MW gross average
	Unit 2	1	GE reheat tandem compound, double-flow turbine rated for nominal 2,400 psig 1,000° F steam, with condenser and hydrogen-cooled generator rated for 500 MW gross average
	Unit 3	1	GE reheat tandem compound, double-flow turbine rated for 2,400 psig 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 525 MW gross average
	Unit 4	1	GE reheat tandem compound, double-flow turbine rated for 2,400 psig 1,000° F steam, and hydrogen-cooled generator rated for 525 MW gross average

Table 2.4-2 (Continued)
Ghent Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Draft System	Unit 1	2	FD fans (50 percent nom)
		2	Ljungstrom rotating, regenerative-type, vertical shaft, horizontally mounted air preheaters
		2	ID fans (50 percent nom)
	Unit 2	2	FD fans (50 percent nom) with inlet vane volume control
			Ljungstrom rotating, regenerative-type, vertical shaft, horizontally mounted air preheaters
			ID fans (50 percent nom)
	Unit 3	3	Three Green Fan Company primary air (PA) fans with GE electric motors rated at 4,750 hp (50 percent nom.)
		2	FD fans (50 percent nom.)
		2	Air Preheater Corporation tri-sector air heaters with Yuba air preheating coils
		2	New Flaktwood Axial ID fans installed in 2007 with FGD installation project
	Unit 4	3	Green Fan Company PA fans with GE electric motors rated at 4,750 hp (50 percent nom.)
		2	Sturtevant Westinghouse FD fans with variable inlet guide vanes and Westinghouse 3,000 hp motors (50 percent nom.)
		2	Air Preheater Corporation tri-sector air heaters with Yuba air preheating coils
		2	Green Fan Company ID fans with variable inlet guide vanes and two-speed Electric Machinery Co. 8,000 hp motors; proposed for replacement in 2008/2009 with FGD installation project. (50 percent nom.)
Condenser	Unit 1	1	Two-pass vacuum condenser
	Unit 2	1	Two-pass vacuum condenser
	Unit 3	1	Two-pass vacuum condenser
	Unit 4	1	Two-pass vacuum condenser
Circulating Water System	Unit 1	2	Circulating water pumps (50 percent nom.)
		1	Mechanical draft cooling tower
	Unit 2	2	Circulating water pumps (50 percent nom.)
		1	Mechanical draft cooling tower
	Unit 3	2	Circulating water pumps (50 percent nom.)
		1	Mechanical draft cooling tower
	Unit 4	2	Circulating water pumps (50 percent nom.)
		1	Mechanical draft cooling tower

Table 2.4-2 (Continued)
Ghent Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Generator	Unit 1	1	Westinghouse Electric, frame 2-104X245, rated 640MVA, 18 kV, 525V excitation, H_2/water cooled, 0.9 PF
	Unit 2	1	GE serial 180X687, rated 618MVA, 22 kV, H_2/water cooled, 0.9 PF
	Unit 3	1	GE serial 180X800, rated 618 MVA, 22 kV, H_2/water cooled, 0.9 PF
	Unit 4	1	GE serial 180X856, rated 618 MVA, 22 kV, H2/water cooled, 0.9 PF
Control Systems	Unit 1	1	Emerson Ovation installed in 2005-2009
	Unit 2	1	Emerson Ovation installed in 2005-2009
	Unit 3	1	Emerson Ovation installed in 2005-2009
	Unit 4	1	Emerson Ovation installed in 2005-2009
Condensate and Feedwater Systems	Unit 1	3	Vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Byron Jackson centrifugal, barrel, 5-stage boiler feed pumps with GE steam turbine drives rated at 11,429 hp and 5,800 rpm (50 percent nom.)
	Unit 2	3	Vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Byron Jackson centrifugal, barrel, 5-stage boiler feed pumps with Westinghouse steam turbine drives rated at 12,000 hp and 5,800 rpm (50 percent nom.)
	Unit 3	3	Vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Byron Jackson centrifugal, barrel, 5-stage boiler feed pumps with Westinghouse steam turbine drives rated at 12,000 hp and 5,800 rpm (50 percent nom.)
	Unit 4	3	Vertical, centrifugal, multistage axial condensate pumps (50 percent nom.)
		2	Byron Jackson centrifugal, barrel, 5-stage boiler feed pumps with Westinghouse steam turbine drives rated at 12,000 hp and 5,800 rpm (50 percent nom.)

Table 2-4-2 (Continued)
Ghent Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Flue Gas Treatment	Unit 1	1	Cold-side dry ESP for PM removal Babcock Power limestone-based FGD system (under construction) SCR and low NO_x burner combustion controls
	Unit 2	1	Hot-side dry ESP for PM removal B&W wet limestone FGD, originally designed for GH1 original construction, to be switched over to handle GH2 in near future Low NO_x burner combustion controls
	Unit 3	1	Hot-side dry ESP for PM removal New limestone-based FGD system designed for 98.5 percent SO_2 removal SCR and low NO_x burner combustion controls
	Unit 4	1	Hot-side dry ESP for PM removal New limestone-based FGD system designed for 98.5 percent SO_2 removal SCR and low NO_x burner combustion controls
Electrical System	Unit 1	1	Westinghouse 18 kV-144 kV, 550/616 MVA, 55° C/65° C
	Unit 2	1	McGraw Edison 21 kV-345 kV, 40/604 MVA, 55° C/65° C
	Unit 3	1	ABB 21 kV-345kV, 40/604 MVA, 55° C/65° C
	Unit 4	1	ABB 21 kV-345kV, 40/604 MVA, 55° C/65° C

The plant has recently made a transition to high sulfur coal, and GH1, GH3, and GH4 currently burn high sulfur coal. GH2 is the only unit still burning low sulfur coal.

Boilers

There are four boilers at Ghent Station. GH1 and GH2 have CE subcritical, controlled circulation boilers. GH3 and GH4 have FW subcritical, natural circulation boilers. All four boilers are balanced draft boilers with reheater, with a main steam flow maximum continuous main rating of 3,800,000 lb/h at 2,620 psig and 1005° F.

Steam Turbine Generators

GH1 has a Westinghouse steam turbine generator, and GH2, GH3, and GH4 have GE steam turbine generators. Each turbine is a reheat tandem compound, double-flow unit and is rated for nominal 2,400 psig 1,000° F steam, with a condenser and hydrogen-cooled generator rated from 500 to 525 MW gross average.

Control Systems

The protective relaying in the plant is almost all the original, electro-mechanical type, discrete function design components manufactured by Westinghouse/ABB type CO and GE BDD for differential.

Emissions Systems

All four boilers were modified by installation of new burners to reduce NO_x emissions. While GH1 and GH2 use LNCFS II burners, GH3 and GH4 use advanced burner technology. The burner installation dates are as follows: GH1 - 1994, GH2 - 2000, and GH3 and GH4 - 1998.

GH1 has two ESPs that were supplied by PECO as part of the original GH1 construction. For GH2, two ESPs were supplied as part of the original unit construction. The GH2 ESPs are located prior to air heater where it operates in a temperature range of 700° F, or in a configuration typically called a "hot-side ESP." For GH3 and GH4, two ESPs were supplied by Envirotech/Buell as part of the original GH3 construction.

Original construction of GH1 did not include a FGD system. The GH1 unit was retrofit with a wet limestone FGD supplied by B&W in 1994. It is important to note that this FGD equipment will be switched in the near future to handle the flue gas from GH2. A new GH1 FGD system is being built by Babcock Power to treat the flue gas of GH1, so as to allow the original GH1 FGD system to be converted to serving GH2. GH3 has a newly constructed and commissioned (2007), limestone-based, FGD system that utilizes a single countercurrent, open spray tower absorber with an integral reaction slurry tank, slurry recirculation system and in situ forced oxidation. GH4 has a newly constructed and commissioned (2008), limestone-based, FGD system that utilizes a single countercurrent, open spray tower absorber with an integral reaction slurry tank, slurry recirculation system and in-situ forced oxidation. This scrubber is essentially a duplicate of the GH3 FGD and the GH3 description of the system also represents GH4.

GH1 has a SCR system designed to reduce the outlet NO_x concentration by 90 percent that was installed by Babcock Power Inc. GH2 does not have an SCR. GH3 has a SCR system designed to reduce the outlet NO_x concentration by 90 percent that was installed by Babcock Power Inc. GH4 has a SCR system designed to reduce the outlet NO_x concentration by 90 percent that was installed by Babcock Power Inc.

Auxiliary Systems

The station generates the following coal combustion products: bottom ash, pyrites, fly ash, scrubber sludge, and synthetic gypsum. All of the combustion products generated are currently stored onsite, with the exception of the synthetic gypsum, which is currently taken offsite.

The station has two ash treatment basins (ATB): ATB 1 and ATB 2. The bottom ash is collected at the bottom of the boiler of each unit and is sluiced with water to ATB 2. In an emergency, the bottom ash is sluiced to ATB 1. Similar to the bottom ash, pyrites are also sluiced to ATB 2. Fly ash is collected in the economizer section of the boilers, duct hoppers, and in the ESPs, and is sluiced to ATB 2.

The draft system for each unit consists of two FD fans and two ID fans. All four units have centrifugal axial multistage condensate pumps and air preheaters. Each unit has five-stage boiler feed pumps rated at 11,300 to 12,000 hp and 5,600 to 5,800 rpm. While unit GH1 and GH2 have Byron Jackson feed pumps, GH3 and GH4 have Pacific Centrifugal feed pumps. Units GH3 and GH4 have primary air fans with GE electric motors rated at 4,750 hp.

Fuel Supply

Coal is brought to the plant solely by barge on the Ohio River, and there are no provisions for rail or truck unloading.

There is a stacker-reclaimer that can stack out 3,600 tons of coal per hour and can reclaim 2,400 tons of coal per hour. There is also a reclaim hopper that can feed 2,400 tons per hour. There are four earth movers and two truck dozers.

GH1 receives pulverized coal from six CE 863 RS Raymond Bowl pulverizer mills. GH2 and GH3 receive coal from six CE 903 RP Raymond bowl mills. GH4 receives coal from six MB-23 mills.

Limestone is supplied by barge on the Ohio River, and ammonia, in anhydrous form, is delivered by truck to a storage facility located immediately across Highway 42 from the plant site.

Water and Wastewater

Cooling water is supplied at Ghent Station from the Ohio River. All four units utilize mechanical draft cooling towers for heat rejection.. Drinking water is supplied by Carroll County Water District No. 1. Five onsite groundwater supply wells provide makeup water for the deionizers.

Ghent Station has a KPDES wastewater discharge permit (Permit. No. KY0002038), effective July 2002 (as modified July 1, 2004).

Electrical and Interconnection

The GSU transformer for GH1 has a rating of 18 kV to 144 kV, 550/616 MVA, 55° C/65° C. The GSU transformers for GH2, GH3, and GH4 are all rated 21 kV to 345 kV, 40/604 MVA, 55° C/65° C. The transformers are the original equipment of the plant and were manufactured by Westinghouse (GH1), McGraw Edison (GH2), and ABB (GH3 and GH4). There is an isolated-phase bus duct routed between the generator and the GSU transformer.

Each unit has main station 125 VDC batteries of the flooded wet cell type. There are also three different types of switchgears used at Ghent: 25 kV, 4.16 kV, and 480 V. Ghent also uses medium voltage motors manufactured by GE, Westinghouse, and others.

2.4.3 Performance

Table 2.4-3 shows the historical net generation, capacity factor, EAF, and EFOR for Ghent. The table also shows the industry averages for capacity factor, EAF, and EFOR. Industry average data come from GADS provided by the NERC and are for units in the SERC and RFC NERC regions and the years 2000 to 2006. The industry averages are as reported for units between 450 and 650 MW.

In general, the Ghent Generating Station average EAF and EFOR for the years 2004 to 2007 were comparable to industry averages. However, there were outage activities in the past 4 years that affected the EAF and EFOR of certain units. These events are listed below:

Table 2.4-3
Historical Performance Data for Ghent Generating Station Units 1 to 4

	2004	2005	2006	2007	Average
Unit 1					

Net Generation (MWh)	3,304,417	3,488,619	3,374,404	2,915,043	3,270,621
Net Heat Rate (Btu/kWh)	10,397	10,303	10,628	10,637	10,485
Capacity Factor (%)	80.0	84.5	81.7	70.6	79.2
Industry Average CF (%)					*65.2*
Equivalent Availability Factor (%)	84.7	87.8	89.4	72.6	83.6
Industry Average EAF (%)					*82.9*
Equivalent Forced Outage Rate (%)	3.0	4.6	3.5	7.9	4.8
Industry Average EFOR (%)					*7.4*
Unit 2					
Net Generation (MWh)	2,843,658	2,762,178	3,013,392	3,454,216	3,018,361
Net Heat Rate (Btu/kWh)	10,308	10,232	10,145	10,158	10,207
Capacity Factor (%)	63.3	66.4	72.4	83.0	71.3
Industry Average CF (%)					*65.2*
Equivalent Availability Factor (%)	92.8	81.1	86.5	90.7	87.8
Industry Average EAF (%)					*82.9*
Equivalent Forced Outage Rate (%)	1.3	3.9	3.5	3.8	3.1
Industry Average EFOR (%)					*7.4*
Unit 3					
Net Generation (MWh)	2,829,972	3,086,506	2,967,905	2,358,308	2,810,673
Net Heat Rate (Btu/kWh)	10,546	10,670	10,957	10,876	10,758
Capacity Factor (%)	67.2	73.3	70.4	56.0	66.7
Industry Average CF (%)					*65.2*
Equivalent Availability Factor (%)	89.0	90.8	86.1	63.5	82.4
Industry Average EAF (%)					*82.9*
Equivalent Forced Outage Rate (%)	1.6	1.7	3.5	14.9	5.4
Industry Average EFOR (%)					*7.4*

Table 2.4-3 (Continued)
Historical Performance Data for Ghent Generating Station 4 Units

	2004	2005	2006	2007	Average
Unit 4					
Net Generation (MWh)	3,088,747	3,249,370	2,852,022	3,232,661	3,105,700
Net Heat Rate (Btu/kWh)	10,325	10,110	10,663	10,678	10,438
Capacity Factor (%)	71.4	75.1	65.9	74.7	71.8
Industry Average CF (%)					*65.2*
Equivalent Availability Factor (%)	94.1	93.0	85.2	92.8	91.3
Industry Average EAF (%)					*82.9*
Equivalent Forced Outage Rate (%)	0.3	1.5	3.4	8.0	3.3
Industry Average EFOR (%)					*7.4*

- In the fall of 2007, GH1 was down for the scheduled 2 month major steam turbine overhaul. The unit was also taken off-line separately during the spring for several weeks to perform plant modifications associated with installation of new environmental systems projects.
- In 2007, GH3 was down for approximately 10 weeks in the spring to perform the new FGD system tie-in and commissioning.
- In 2007, GH3 experienced several forced outage events due to problems with the new ID fans associated with the new FGD system. The ID fans were replaced as part of the FGD project commissioned in 2007. The axial type fans had variable blade bearing problems and caused numerous forced outages and derates. EON submitted a warranty claim to the fan vendor due to the lack of performance. A modified design was installed by the vendor in June 2008. In addition, GH3 in 2007 also experienced 296 unplanned outage hours due to superheater tube leaks. An ongoing issue with the GH3 superheater is solid tube spacer crack problems. These boiler spacer ties tend to crack and propagate into tube failures. EON is aware of these problems and is looking into possible solutions, such as improving the quality, alignment, and distribution during installation of the tubes, as well as replacing cracked spacers instead of repairing them. Appropriate O&M appears to have been allocated to address these issues to ensure improved reliability and reduced EFOR in the near future.

Based on interviews with plant personnel and review of documentation provided, except as otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget.

2.4.4 Operations and Maintenance

A review of the organization chart and discussions about staffing with EON staff indicated that the operations group is separated into four operating groups (A through D) for plant operations and fuel yard management. There is also a dedicated laboratory group with six lab technicians. Also of note are the dedicated outage coordinator and the four planning positions in the maintenance organization.

Using four operating groups is a common and recommended practice to address the challenges of covering round-the-clock operations while also maintaining a cohesive "team" of operators. Using a dedicated outage coordinator is a recommended practice to ensure that outage activities are adequately planned and given the appropriate priority. This position is complemented with respect to the daily planning requirements with a complement of four planners.

Overall, the station currently has approximately 200 employees. This level appears appropriate, given the number of units and the complexity of the systems at the facilities.

A review of the plant training programs identified a comprehensive program for operators that includes initial qualification, continuous reassessment, and refresher training. Training documents included extensive details regarding specific plant systems, as well as general or introductory training programs to ensure that the students are well versed in the fundamentals. In addition to the operations, focused training elements plans are in place to review the training needs matrix for the maintenance departments.

Ghent provided a large number of example operating procedures for review. These procedures are broken into sections of the plant to address FGD, SCR, and BOP separately. These procedures seem to focus on abnormal events and specific issues or actions. The guidelines for unit startup appear somewhat limited in detail and would require a very experienced operator to know how to execute all of the instructions noted. There was no indication in the procedures of how often they are reviewed or who would need to be involved in the review. However, the Ghent Station Operating Plan specifically calls for additions and enhancements to the current operating procedures. The plan noted the need to reformat and update various different (but specific) startup and shutdown procedures. The plan outlined not only the systems that need to be addressed, but also the timeline for completion of each respective system. Given that timeline, a significant portion of this work may already be completed.

Ghent, like all the other EON assets, utilizes the Maximo CMMS application for maintenance planning and associated work management functions. Extensive application of the capabilities of Maximo is an integral part of the best practices identified by EON as part of a Regulated Generation Business Plan. In addition to the work management effort, Ghent is also implementing the boiler circuit maintenance strategy as outlined for all the EON assets.

Ghent has also instituted a number of strategic alliances to enhance the maintenance processes. This effort includes contracts to address boiler outage maintenance, cooling tower construction, mechanical maintenance, facilities support, and coal yard equipment operations. The facility is also looking to develop additional relationships to that could provide needed skills and/or resources.

The PDM program is continuing to develop, while enjoying substantial success from current efforts. PDM applications include infrared (IR) thermography, vibration analysis, oil sampling, and motor current analysis. In the reports provided, the PDM team noted that the culture and acceptance of PDM technologies and their application has been enhanced as the technicians observe potential issues beyond the specific technology being applied. They noted, as an example, that as they walk down units prior to outages with the IR thermography camera looking for problems with leaking valves, switchgear, substations, hot bearings, conveyor rolls, motors, steam leaks, duct cold air intake, and loose boiler insulation, they are also observing the equipment and noting any unusual issues that may also need to be addressed

Application of PDM technologies has included performing vibration analysis and checks on more than 500 pieces of equipment (routine), more than 200 equipment (nonroutine) and performing oil sampling on equipment with 10 or more gallons on more than 200 pieces of equipment. The team has also performed motor analysis on approximately 130 pieces of equipment and annual thermal scans on all switchgears, motor control centers (MCCs), and substations. All of this is in addition to the boiler circuit management efforts and the combustion improvement activities.

The station planning cycle currently calls for outage and overhaul strategies that include an annual boiler outage of approximately 3 weeks and an 8 week turbine outage every 6 to 7 years. In addition, the units also plan for chemical cleaning of the boiler water wall circuits every 4 years for GH1, GH3, and GH4. These schedules are consistent with prudent generating asset management practices.

O&M Historical Expenses

The historical operating costs for Ghent are outlined in Table 2.4-4.

Table 2.4-4
Ghent Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$33,685	$32,291	$34,639	$35,829	$43,956
Other Cost of Services		$2,978	$2,299	$3,084	$3,920
Fuel Handling	$1,756	$1,820	$1,945	$2,015	$2,235
Below the Line	$669	$25	$17	$6	$10
Total Controllable	$36,110	$37,114	$38,900	$40,934	$50,121
Net Generation (GWH)	11453	11723	12587	12460	11961
Controllable/MWh	$3.15	$3.17	$3.09	$3.29	$4.19

2.4.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the plant on July 15 and 16, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil or steam, corrosion damage, or other distress. Some water leaks from equipment were noticed in the lower levels; however, these areas were barricaded off to prevent access. The water leaks are not considered unusual, considering the age of the plant. The access and space availability on the site is limited by the current ongoing construction of a new FGD system for Unit 1, but this appears to be managed in a reasonable manner.

Electrical rooms were clean and not used as storage for unrelated items. Battery rooms were locked and kept clean. The floor space in front of the switchgear was clear open for operation activities. The control room and plant lighting was functioning properly. Electrical rooms have been added around the electrical switchgear for arc flash safety reasons. However, some of the new room construction appeared to have poor ventilation. The station maintenance personnel interviewed indicated that a project was planned to improve the ventilation of these rooms.

Boilers

Change of the station's historical fuel type to Illinois Basin coal or high sulfur coal appear to have increased erosion to all four boiler economizers, reheaters, superheaters, and outlet headers. The impacts have been identified in GH1 and GH2 water wall slopes from slag damage, GH3 and GH4's solid tube spacer cracking, and the potential for soot blowing-related erosion. Blistering of the GH3 and GH4 water wall due to internal deposits is also evident and requires continued monitoring and repairs. The replacements and upgrades of major boiler components are included in the capital plan to address these problems.

In 2007, GH1 was thoroughly inspected at nearly all areas of the boiler, with full scaffolding that provided excellent access for all components required. The inspection found that approximately 1/3 of the slope was bridged by slag buildup, and the added weight damaged support struts throughout the lower dead air spaces. The damage was subsequently repaired or replaced. EON plans to continue to monitor and replace these components as required.

A minor inspection of GH2 was undertaken by the original boiler manufacturer in 2007. The boiler manufacturer recommended that the front reheat section be upgraded to stainless material (similar to GH1) to prevent future problems from coal ash corrosion, and that the economizer be replaced to avoid possible failure from fly ash erosion and worsening of pluggage. Based on these findings, EON has included plans to replace the GH2 reheater tubes, pendants, and economizers in the budgeted capital plan through 2012. EON also plans to replace the GH2 reheat header as a precaution to avoid running into the same problems found at GH1.

A GH3 inspection was carried out in 2007 by the original boiler manufacturer. At that time, a condition assessment of the reheat outlet header was performed. It was found during the assessment that 30 percent of the header nipples were in deteriorated condition, with 50 to 60 percent original wall thickness remaining. Type 3A creep-damage (oriented cavitation) was identified in two tube-to-header weld replications. Oxide scale, pitting, and external wastage were also found on the reheat outlet terminal tubes. Because of these noted concerns, Alstom recommended that select terminal tubes and the header be replaced. However, EON's current plan is to replace select terminal tubes based on condition assessment and to continue testing and monitoring the header to further assess its condition.

The condition of the GH4 reheat outlet header is unknown at this time, but the header is planned for inspection in 2008. In consideration of the findings on the GH3 reheat header, the boiler manufacturer has recommended a thorough inspection be performed.

Steam Turbines

All four of the Ghent Station steam turbines are cleaned with a special process on approximately a semiannual basis to remove copper deposits that could cause lost capacity of approximately 2 MW per month for 9 months--up to 20 MW loss from their overhauled condition. EON plans to replace several of the remaining feedwater heaters built with tubing containing copper during the planning period from 2009 to 2012. This will help to minimize this issue.

The GH1 steam turbine rotor has more than 249,000 hours of operation as of June 2008. GH1 recently underwent a major turbine overhaul, at which time several issues were found. The unit was returned to service was slightly elevated vibration (4.2 mils) at Bearing No. 2. At present, EON is monitoring the vibration level closely while waiting for the final analysis results and recommendations in the spring 2008 outage report that Siemens will release soon. The recommended capital projects required to address these issues have recently been added to the 2009 to 2012 time period capital plan:

- No. 1 IP blade ring replacement ($1,350,000).
- No. 2 IP blade ring replacement ($975,000).
- IP dummy blade ring replacement ($550,000).
- Throttle valves seat restoration ($400,000).

The GH2 steam turbine rotor has more than 220,000 hours of operation as of June 2008. GH2 steam turbine was overhauled in 2005. A rotor bore inspection of the HP-IP rotor revealed that no internal change occurred in the rotor between 1996 and 2005; therefore, GE recommended reinspecting the rotor after an additional 10 years of service.

The GH3 steam turbine rotor has more than 183,000 hours of operation as of June 2008. The GH3 steam turbine was last overhauled in 2003. The inspection of the rotors found them to be in good overall condition, with a minor crack in an LP cover that was weld repaired. Significant leakage was noticed at the existing HP and reheat section packing and spill strip. These packing and spill strips were refurbished or replaced, as recommended. All of the bearings were found to be in good condition, except for the T-1 and T-2 Double Tilt Pad bearings, which were refurbished.

The GH4 steam turbine rotor has more than 175,000 hours of operation as of June 2008. In 2002, the GH4 steam turbine was overhauled. The activities undertaken included onsite bucket replacements, diaphragm repairs, machining of rotor journals, low speed balancing of all three rotors, repair to main turbine thrust bearings, and valve maintenance. The HP-IP and both LP rotors were inspected, with no significant deficiencies found.

Balance-of-Plant

The original ID fans and motors at GH4 presently remain in operation, with a derate of approximately 25 to 45 MW, because of the added pressure drop across the new FGD system. Final resolution of this ID fan issue is under consideration by EON. Possible resolutions to resolve this issue include retipping the fan rotors (completed) and adding motor horsepower to the original GH4 ID fans, or commissioning the new axial-type ID fans, if the reliability of this supplier's design modifications is found successful at GH3. The hot-side ESPs have been problematic with the ESP on GH2 causing the most hours of planned and forced outages at 1,430 hours for the last 3 years, while GH3 and GH4 had approximately 380 and 230 outage hours, respectively. The plant personnel noted that flexibility in the station outage schedule is limited by the impacts of the hot-side performance, which require outages to allow cleaning of the ESP. Hot-side precipitators have presented this type of operating challenge for decades, since they were introduced in the power industry to try to assist in collecting the ash of low sulfur coals. Their reliability is typically compromised by sodium depletion in the ash layer, which serves to adhere a high resistivity ash layer to the plates that electrically insulates the electrodes and reduces power generation of the ESP. The costs and loss generation due to the cleanings and the impacts to the plant operation from excess air in leakage, due to the elevated temperatures and thermal expansion, has caused many hot side ESPs to be converted to cold-side units. To prevent damage from these frequent cleanings, the plant personnel have decided that all future ESP cleans will normally be completed by dry grit blasting to reduce long-term damage to the equipment.

2.4.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.4. From the information provided, the existing Ghent Station appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON correspondence from November 2007 indicated that the EPA is interested in the increase in sulfuric acid mist (SAM) emissions and thereby the potential to trigger NSR Prevention of Significant Deterioration (PSD) requirements due to the previous installation of the SCR systems on GH1, GH3, and GH4. While correspondence indicates that the installations were made under the authority of an approval letter from the Kentucky Division of Air Quality (KDAQ) and during the time period when Pollution Control Projects (PCPs) were still allowed under the EPA rule, there has been no resolution to the issue of EPA's inquiry.
- Similar to the above issue, company planning documents indicate several air PCPs have either recently been completed or are in planning stages (including new stacks, wet FGD systems, sulfur trioxide [SO_3] mitigation systems, and an SCR system). An application submittal and approval letter from the KDAQ for the SO_3 mitigation systems was available for review. Additionally, a submittal letter for the wet FGD application (without supporting information) and an approval letter from the KDAQ from January and February 2005, respectively, were available for review. The approval letter from the KDAQ indicated that the minor permit modification for the project was classified as "environmentally beneficial" or otherwise known as a PCP. However, no additional information was found indicating that these changes at Ghent Station underwent the necessary permitting review and met the applicable requirements in light of the vacature of the NSR PCP exemption on June 24, 2005. This would also include current or anticipated changes in material handling (fuel and byproduct) due to the addition of the FGD system. However, when notified of this issue , EON indicated that the KDAQ does not consider the vacature a concern for its FGD projects because the coincidental increases of particulate from the associated material handling systems were included in the application and were less than the applicable significance level.
- A Notice of Violation (NOV) was issued by the EPA on September 26, 2007, for opacity violations based on EPA Method 9 observations on June 20, 2007. The 2007 Annual Compliance Certification indicates that EON met with the EPA on November 20, 2007, and is currently awaiting EPA response.

- EON submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with permit conditions, with the exception of the following items:
  - GH1 was in continuous compliance, except for 2 hours of PM exceedances and the September 26, 2007, NOV for opacity.
  - GH2 was in continuous compliance, except for opacity exceedances less than 0.5 percent of operating time and five SO_2 exceedances.
  - GH3 was in continuous compliance, except for opacity exceedances, which totaled 1.08 percent and 2 hours of PM exceedances.
  - GH4 was in continuous compliance, except for opacity exceedances, which totaled 1.08 percent and 2 hours of SO_2 exceedances.
- The opacity exceedances were primarily due to startups, shutdowns, load changes, blowing, precipitator trouble, and unit trip/upset. The SO_2 exceedances were due to fuel problems.
- The KDAQ performed an onsite tour/inspection of the facility in 2007 and documented the results in a report titled *DAQ-Full Compliance Evaluation*, dated December 21, 2007. The official overall compliance status is listed as "Out of Comp. - Viol documented." The inspection report noted numerous opacity violations, such as the following:
  - GH2 experienced 249 six minute opacity violations between January 1, 2007, and September 30, 2007; relief was granted for 180 of them.
  - Stack 3/4 experienced 119 six minute opacity violations between January 1, 2007, and March 31, 2007; relief was granted for 28 of them on GH3.
  - There is no mention of what is to become of the violations for which no relief was granted.

Other

- As observed during the Black & Veatch site visit, adequate long-term options for disposal and storage of combustion products is one of the most critical issues for Ghent at present. The need for additional product disposal/storage is critical. A study has been performed, and a plan is presently being finalized to construct a new ash pond, landfills, or a combination, to provide another 25 years of storage. According to EON, the decision as to which plan to implement will be made in the near future.

2.4.7 Key Findings

- Ghent appears to have the required environmental permits in place and to be operating in substantial compliance with permit and regulatory requirements.
- The extensive construction program at this plant over the last several years of adding new SO_2 and NO_x controls has positioned the station well for meeting current and future air emissions regulations, including mercury (Hg) regulations if the co-benefit control of the existing air quality control technologies is as high as may be expected. GH1, GH3, and GH4 will have wet FGD, SCR system, SO_3 controls, and PM controls. Unit 2 also has similar projects planned, except for the SCR system, which is targeted for the future.
- The current capacity for long-term disposal of combustion byproducts, such as gypsum byproduct from the FGD process and ash disposal, will likely be exhausted by 2013. The plant is currently reviewing several possible solutions to address this problem. A cost allowance for capital projects to address this issue has been included in the EON forecasted capital cost budget.
- The facility is in the process of switching the primary fuel to Illinois Basin coal or other high sulfur coal. Since it is expected that potential for slag fall, erosion damage, and fireside corrosion in some boiler units may increase, EON has allocated approximately $23 million for boiler component replacements to address these potential problems.
- The GH1 steam turbine was recently overhauled in 2008, but returned to service with higher than normal vibration. EON is aware of the problem and is also planning to implement the recommended IP blade ring replacement project (at a cost of approximately $3 million) at the next outage.

2.5 E.W. Brown Generating Station

2.5.1 Introduction

The E.W. Brown Station, as illustrated on Figure 2.5-1, is located on Herrington Lake in Mercer County, Kentucky, between Shakertown and Burgin, off of Hwy 33. The station was constructed on the west side of Herrington Lake, the impoundment behind Dix Dam. Table 2.5-1 provides a summary of the E.W. Brown plant facts.

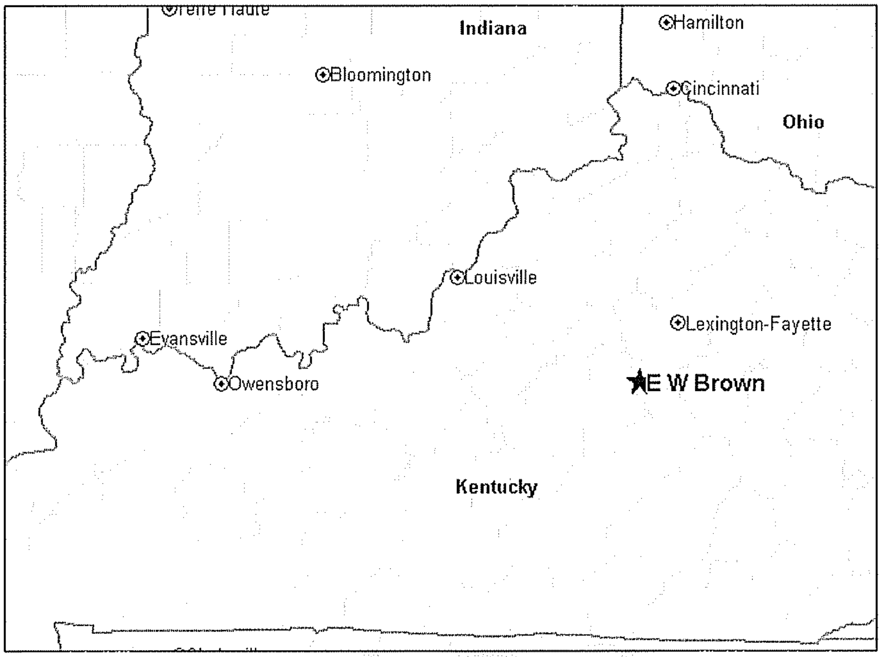

Figure 2.5-1
Location of E.W. Brown Generating Station

Table 2.5-1
E.W. Brown Generating Station Fact Sheet

Category	Data	Category	Data
Location:	Burgin, KY	**Market Area:**	Midwest
Nominal Capacity:	700.5 MW net	**Off-Take:**	EON network customers
Ownership:	KU - 100%	**Electric Interconnection:**	Brown 138kV Substation (Units 1, 2, and 3)
Fuel:	Coal	**Fuel Supply:**	Contract and spot
Type:	Pulverized coal, subcritical fired steam generators	**COD:**	May 1, 1957 (Unit 1) June 1, 1963 (Unit 2) July 1, 1971 (Unit 3)
Equipment:	2 x CE boilers, 1 x B&W boiler, and 3 x Westinghouse steam turbines	**Operator:**	KU

Notes:
1. Capacity represents 100 percent of average (winter, summer) net electrical output.

The plant began commercial operation in 1957. The station includes three coal fired electric generating units with a total nameplate capacity of 740 MW gross and 700 MW net. The electrical power from the E.W. Brown Station units is used to provide both load and voltage support for the 138 kV transmission systems.

The project is owned by KU, and its electrical interconnection is through the E.W. Brown 138 kV Substation. Units 1, 2, and 3 (BR1, BR2, and BR3) are designated as network resource generating units on the EON transmission system. The full load output from these units can be used to serve the network customers interconnected to the EON transmission system.

Coal is delivered to the E.W. Brown Generating Station primarily by unit train. The plant uses 5,000 to 6,000 tons of coal per day. The fuel supply is provided through a combination of fuel supply contracts and the spot market.

Water supply is withdrawn from Herrington Lake. The water is used for plant service water, potable water, fire water, makeup for the cooling towers, and makeup to the steam/condensate cycles.

2.5.2 Plant Description and Design

Siting and Real Estate

The E.W. Brown Station, pictured on Figure 2.5-2, is located on the western shore of Herrington Lake in Mercer County, Kentucky, between Shakertown and Burgin, off of Hwy 33. The sole plant access road off of Hwy 33 is Hwy 342, also known as Dix Dam Road. The plant is located approximately 1.3 miles off of Hwy 33.

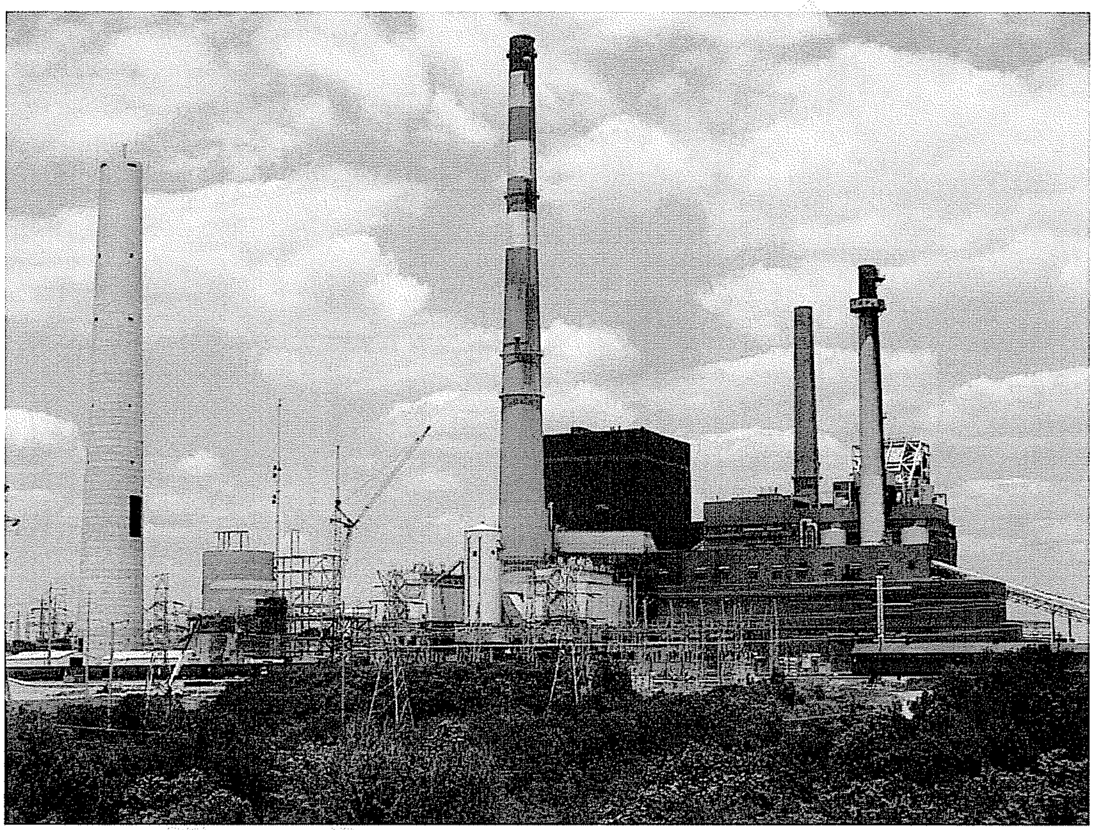

Figure 2.5-2
E.W. Brown Generating Station

Equipment

The plant consists of three coal fired generating units (BR1, BR2, and BR3) with 740 MW total gross output. The major plant equipment is listed in Table 2.5-2.

Table 2.5-2
E.W. Brown Station Major Equipment

Description	Unit	Quantity	Characteristics
Boiler	Unit 1	1	B&W balanced draft Carolina type radiant boiler with reheater originally designed to fire low sulfur Kentucky bituminous coal, rated for 750,000 lb/h of steam at 1,500 psig and 1,005° F
	Unit 2	1	CE natural circulation steam generator boiler with reheater originally designed to fire low sulfur Kentucky bituminous coal, rated for 1,100,000 lb/h of steam at 1,870 psig and 1,005° F
	Unit 3	1	CE controlled circulation radiant reheat steam generator boiler with reheater originally designed to fire low sulfur Kentucky bituminous coal. The boiler was rated for 3,025,000 lb/h of steam at 2,620 psig and 1005° F
Steam Turbine	Unit 1	1	Westinghouse reheat tandem compound, double-flow turbine, rated for 1,450 psig and 1,000° F steam, and hydrogen-cooled generator rated for 110 MW gross average
	Unit 2	1	Westinghouse reheat tandem compound, double-flow turbine, rated for 1,800 psig and 1000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 179 MW gross avg
	Unit 3	1	Westinghouse reheat tandem compound, double-flow turbine rated for 2,400 psig and 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 456 MW gross avg
Draft System	Unit 1	2	Westinghouse FD fans with variable speed hydraulic couplings (50 percent nom.)
		2	Ljungstrom rotating, regenerative-type, vertical shaft, horizontally mounted air preheaters with one external recirculation air fan (50 percent nom.)

Table 2.5-2 (Continued)
E.W. Brown Station Major Equipment

Description	Unit	Quantity	Characteristics
	Unit 1	2	Westinghouse ID fans with variable speed hydraulic couplings (50 percent nom.)
	Unit 2	2	Sturtevant Westinghouse FD fans with variable speed hydraulic couplings and 1,250 hp electric motors (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters and Buffalo Forge preheating coils with coil pumps (50 percent nom.)
		2	R.J. Perkins Co. inlet vane controlled ID fans with 2,500 hp Westinghouse two-speed motor drives (50 percent nom.)
	Unit 3	2	Sturtevant-Westinghouse FD fans with variable speed hydraulic couplings (50 percent nom.)
		2	Ljungstrom rotating, regenerative type, vertical shaft, horizontally mounted air preheaters with American Standard preheating coils and coil pumps
		2	Westinghouse ID fans with inlet control vanes and 6,000 hp Westinghouse two-speed motors (50 percent nom.)
Condenser	Unit 1	1	Two-pass vacuum condenser
	Unit 2	1	Two-pass vacuum condenser
	Unit 3	1	Two-pass vacuum condenser
Circulating Water System	Unit 1	2	Circulating water pumps (50 percent nom.)
		1	Mechanical draft cooling tower
	Unit 2	2	Circulating water pumps (50-percent nom.)
		1	Mechanical draft cooling tower
	Unit 3	2	Circulating water pumps (50 percent nom.)
		2	Mechanical draft cooling towers
Generator	Unit 1	1	Westinghouse Frame 2-092X150, rated 114 MW, 13.8 kV, H_2 cooled
	Unit 2	1	Westinghouse, SO 1-S-65-P-992, rated 180 MW, 18 kV, H_2 cooled
	Unit 3	1	Westinghouse Frame 2-104X225-1, rated 446 MW, 495 MVA, 24 kV, H_2 cooled

Table 2.5-2 (Continued)
E.W. Brown Unit 1 Major Equipment

Description	Unit	Quantity	Characteristics
Control Systems	Unit 1	1	Foxboro IA (2006-2007)
	Unit 2	1	Bailey and is scheduled to be replaced with Foxboro in 2010
	Unit 3	1	Foxboro IA (2005-2007)
Condensate and Feedwater Systems	Unit 1	2	Westinghouse vertical, centrifugal, multi-stage axial condensate pumps (50 percent nom.)
		3	Ingersoll-Rand centrifugal, barrel, 10-stage boiler feed pumps with American Blower variable speed fluid drives and General Electric 1,250 hp motor drivers (50 percent nom.)
	Unit 2	2	Allis-Chalmers vertical, centrifugal, multi-stage axial condensate pumps (50 percent nom.)
		2	Ingersoll-Rand centrifugal, barrel, 10-stage boiler feed pumps with American Standard variable speed fluid drives and General Electric 2,250 hp motor drivers (50 percent nom.)
	Unit 3	2	Allis-Chalmers vertical, centrifugal, multi-stage axial condensate pumps (50 percent nom.)
		2	Ingersoll-Rand centrifugal, barrel, 4-stage boiler feed pumps with Westinghouse steam turbine drives (50 percent nom.)
Flue Gas Treatment	Unit 1	1	Cold-side dry ESP for PM removal
			New, common (GH1/2/3) limestone-based FGD system designed for 98.5 percent SO_2 removal (under construction)
			Low-NO_x burner combustion controls.
	Unit 2	1	Cold-side dry ESP for PM removal
			New, common (GH1/2/3) limestone-based FGD system designed for 98.5% SO_2 removal (under construction)
			Low-NO_x burner combustion controls
	Unit 3	1	Cold-side dry ESP for PM removal
			New, common (GH1/2/3) limestone-based FGD system designed for 98.5% SO_2 removal (under construction)
			Low-NO_x burner combustion controls
Electrical System	Unit 1	1	Westinghouse 14.4 kV-138 kV 120 MVA
	Unit 2	1	Westinghouse 18.8 kV-138 kV 185 MVA
	Unit 3	1	McGraw-Edison 24 kV-138 kV 450

Boilers

There are three boilers at the E.W. Brown Generating Station. All three boilers were modified by installation of new burners between 1992 and 1995 to reduce NO_x emissions.

BR1 has a B&W, balanced draft, Carolina type natural circulation radiant boiler designed for Kentucky bituminous low sulfur coal. The unit was designed for a maximum continuous main steam flow of 750,000 lb/h at 1,450 psig with reheat steam flow of 683,000 lb/h and steam temperatures of 1,005° F. BR1 receives pulverized coal from four B&W EL-64 pulverizers, rated to deliver 29,820 lb/h of coal that is fired through 16, single wall DRB-XCL (low NO_x) burners.

The BR1 boiler was originally designed for coal, with a heating value of 13,220 Btu/lb and ash softening temperature of 1,950° F. The BR1 16 low NO_x burners were a retrofit in 1995 to B&W, DRB-XCL System.

BR2 has a CE natural circulation steam generator designed for Kentucky bituminous low sulfur coal. The unit was designed to deliver 1,100,000 lb/h MCR steam at 1,870 psig and 1,000° F. The unit was originally designed to operate with a pressurized furnace, but has since been converted to balanced draft operation. The unit went commercial in 1963 and had induced draft fans installed around 1974.

BR3 has a CE-controlled circulation, radiant reheat steam generator, originally designed for Kentucky bituminous low sulfur coal. The unit was designed for an MCR steam flow of 3,025,000 lb/h at 2,620 psig, with reheat steam flow of 2,644,000 lb/h and steam temperatures of 1,005° F.

Steam Turbine Generators

The E.W. Brown Generating Station has three Westinghouse steam turbine generators.

BR1 has a Westinghouse reheat tandem compound, double-flow turbine rated for 1,450 psig and 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 114 MW. The BR1 steam turbine rotor has more than 347,000 hours of operation, and 830 total starts (168 cold starts, 489 warm starts, and 173 hot starts) as of June 2008.

BR2 has a Westinghouse reheat tandem compound, double-flow turbine rated for 1,800 psig and 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 180 MW and 94 percent power factor. The BR2 steam turbine has more than 313,000 hours of operation and 643 total starts (506 cold starts and 137 hot starts) as of June 2008.

BR3 has a Westinghouse reheat tandem compound, double-flow turbine rated for 2400 psig and 1,000° F steam, with a two-pass condenser and hydrogen-cooled generator rated for 446 MW and 90 percent power factor. The BR3 steam turbine has more than 256,705 hours of operation and 542 total starts (368 cold starts and 174 hot starts) as of June 2008, except for the LP rotor that was replaced in 1997. The BR3 LP rotor was replaced in 1997 as an output improvement upgrade of capacity up to 446 MW from 409 MW. This project involved rerating for the BR3 generator and is currently reported to be in the final stages of settlement of NSR NOV proceedings.

The BR1 generator is Frame 2-092X150, rated 114 MW, 13.8 kV, hydrogen-cooled, and was placed into service in 1957. The BR2 generator is SO 1-S-65-P-992, rated 180 MW, 18 kV, hydrogen-cooled, and was placed into service in 1963. The BR3 generator is Frame 2-104X225-1, rated 446 MW, 495 MVA, 24 kV, hydrogen-cooled, and was placed into service in 1971. The BR3 generator rotor was rewound during the 1997 output improvement project.

Emissions Systems

All three coal fired units are equipped with low NO_x burners, ESPs, and CEMS.

All three boilers were modified by installation of new burners between 1992 and 1995 to reduce NO_x emissions.

BR1 has a cold-side ESP that was supplied by Buell Engineering as part of a retrofit to Unit 1 in 1973. BR2 has a cold-side ESP that was supplied by the Buell Division of Envirotech as part of a retrofit to the unit in 1975. Two cold-side ESPs are installed on BR3. One ESP was supplied by Research Cottrell as part of the initial design of the unit. Another ESP, which also was supplied by Research Cottrell, was added to the first ESP within several years of initial unit operation in the mid-1970s.

An existing extractive dilution type CEMS is installed on each unit for measuring NO_x, SO_2, CO_2, and stack flow. On BR2, the existing CEMS will remain in service when the FGD system becomes operational, since the stack will still be used to bypass Unit 2 from the FGD system. The BR1 and BR3 systems will be retired, since the flue gas from these units will only be able to be discharged through the FGD to the new stack, which will have a new CEMS unit for measuring NO_x, SO_2, and CO_2 and flow for the flue gas from all three units passing through the stack

The new construction of the FGD system and the level of redundancy that is common with the equipment should allow for reliable operation of the equipment in the future, if the level of initial construction and future maintenance are maintained at normal industry standards.

Flue gas from BR1, BR2, and BR3 will be treated by the single, new, limestone-based FGD system that is being installed as a common system. The new FGD system, which utilizes a countercurrent, open spray tower absorber with an integral reaction slurry tank, slurry recirculation system and in situ forced oxidation, is currently being installed to reduce the SO_2 emissions of the plant by processing the combined flue gas discharges of all three coal fired boiler units at the E.W. Brown Generating Station. Flue gas from each of the three boiler units will be routed through the unit specific ID fans and discharged into new ductwork and then combined and routed to the inlet of the new common absorber tower. A new concrete chimney with a FRP liner will be installed to route the exiting scrubbed flue gas from the FGD absorber to the atmosphere.

Babcock Power Environmental Inc. (BPEI) is the process technology supplier, which is guaranteed to reduce SO_2 emissions by 98 percent.

There are many sections of new flue gas ductwork in the project: inlet duct to each of the new ID fans, discharge duct from the ID fans, bypass ductwork from BR2 to the existing BR3 stack, and combined ductwork to the inlet of the FGD absorber. No bypass will be provided for BR1 orBR3. Five guillotine dampers will be installed in the ductwork for isolating the ID fans and absorber tower.

The FGD addition work is composed of ID fans; inlet ductwork; dampers; expansion joints; absorber inlet duct; absorber cap and outlet duct; chimney; emergency quench system; absorber tower and mist eliminator; absorber reaction oxidation tank; reaction/oxidation tank agitators; oxidation air blowers; absorber recycle system, including recycle pumps, piping and spray nozzles, mist eliminator wash water storage tank, and pumps; absorber bleed/gypsum slurry storage tanks with agitators; and gypsum slurry transfer pumps.

The single absorber will have an integral Stebbins tile lined concrete reaction tank as is typical for other FGD systems in the KU and LG&E system. The absorber tower will be roll-bonded C-686 to carbon steel with external carbon steel stiffeners. Tower access doors will be constructed of C-2000 clad carbon steel.

BR1, BR2 and BR3 will share the new, single module FGD common system. BR2's current stack will be maintained as a bypass stack for BR2 only.

Control Systems

The BR1 and BR3 DCS manufacturer/model is Foxboro IA. The BR2 DCS manufacturer/model is Bailey and is scheduled to be replaced with Foxboro in 2010.

Auxiliary Systems

Ash disposal is all onsite. The ash pond onsite currently receives bottom ash (including pyrites), fly ash, discharges from three different oil/water separators, coal pile runoff, demineralizer and reverse osmosis (RO) system backwash, and red water (ash pond seepage). These wastes are disposed of in a large onsite surface impoundment (ash treatment basin), and then water is discharged into Herrington Lake. The ash treatment basin covers 117.5 acres and was designed for a 25 year storage life.

The site has recently completed a new 56 acre auxiliary ash pond. This auxiliary pond was reported to have all the required permits and was to start receiving ash immediately. The plan is for this auxiliary ash pond to receive all plant fly ash and bottom ash for the next 3 years, during which time a liner will be installed in the original plant ash pond.

Overall, the plant has a 20 year ash disposal plan in place, involving expansion of the existing ash pond. The first phase of the expansion, which is the auxiliary ash pond, has been completed. The next phase will involve installing a liner in the original ash pond, and raising the height of the ash pond berms approximately 60 feet. The construction of this elevated ash pond will occur over a period of 12 years. The ash disposal plan at the station should ensure that there are no disruptions due to ash waste issues.

The BR1 condenser was furnished by Westinghouse as a two-pass, divided water box with inhibited Admiralty, 18 BWG tubes. The BR2 condenser was furnished by Allis-Chalmers as a two water pass, rectangular section, divided, water box design with Admiralty (90Cu-10Ni) tubes. The BR3 condenser was furnished by Ingersoll-Rand as a horizontal surface, multi-steam pass, two water pass rectangular section with 304 stainless steel tubes.

The E.W. Brown Generating Station units are all equipped with two (50 percent capacity) vertical, centrifugal, multistage axial condensate pumps.

BR1 has three boiler feed pumps that were furnished by Ingersoll Rand, with GE 1,250 hp motor drives and American Blower variable speed fluid couplings. BR2 has two 50 percent boiler feed pumps that were furnished by Ingersoll-Rand, with GE 2250 hp motor drives and American Standard variable speed hydraulic couplings. BR3 has two (50 percent capacity) Ingersoll-Rand centrifugal, barrel, 4-stage boiler feed pumps, with Westinghouse steam turbine drives.

Fuel Supply

Coal is delivered to E.W. Brown Generating Station primarily by unit train. The plant can unload 90 railcars in 12-1/2 hours. The plant uses 5,000 to 6,000 tons of coal per day. The coal pile was reported to be maintained at 40 to 60 days of storage. E. W. Brown Generating Station also receives deliveries from 15 to 20 coal trucks per day from the Hazard Mine.

The E. W. Brown units will normally burn 6 pound sulfur coal after the FGD systems are commissioned, instead of the 2 to 3 pound sulfur coal burned in the past. The operating plan for future required FGD maintenance is to perform the required maintenance while BR1 and BR3 are down, and BR2 is in bypass mode. At these times, BR2 will be required to burn 2 to 3 pound sulfur coal. After commissioning the new FGD, there will be a need to segregate coal in the coal yard. This required segregation of coal will be a new process activity at the plant.

Water and Wastewater

Herrington Lake, the reservoir impounded behind Dix Dam, serves as the water supply for the E.W. Brown Generating Station. All waters serving the plant are withdrawn from two intake structures located in the lake. Sanitary wastes are treated in a septic tank and lateral fields, except that CT area sanitary wastes are tanked and privately contracted to a treatment facility.

There has been a recent concern regarding the amount of water that seeps through the Dix Dam. A study released in draft form in April 2008 concluded that the present leakage rate through the dam is not considered alarming, and the structural integrity of the dam is considered intact. However, it was noted that even with the present leakage rate, the water supply to the E.W. Brown Station could be at risk if a severe multiyear drought occurred that lowered the water level behind the dam. At present, the current EON budget includes a $2.2 million project to re-caulk the face slab of Dix Dam, which is scheduled for 2011. Subsection 4.2.5 of this report provides further information about the Dix Dam.

The E.W. Brown Generating Station facility has five oil/water separators and miscellaneous drains are directed to these devices for treatment. Three of the oil/water separators are located at the CT portion of the facility and all five of the oil/water separators discharge to the ash treatment basin prior to discharge to Herrington Lake.

Condenser cooling water is supplied via three mechanical-draft cooling towers in a closed-loop configuration. The makeup water for the cooling towers and cycle makeup is drawn from Herrington Lake.

Electrical and Interconnection

The electrical power output from BR1 and BR2 generators is delivered to the EON 138 kV transmission system through the South Switchyard. The electrical power from BR3 is delivered to the EON 138 kV transmission system through the North Switchyard. The electrical power from the E.W. Brown Station units is used to provide both load and voltage support for the 138 kV transmission systems.

The BR1 GSU transformer has a rating of 14.4 kV-138 kV 120 MVA and was manufactured by Westinghouse. The BR2 GSU transformer has a rating of 18.8 kV-138 kV 185 MVA and was manufactured by Westinghouse. The BR3 GSU transformer has a rating of 24 kV-138 kV 450 MVA and was manufactured by McGraw-Edison.

The electrical power output of the generators is stepped up by GSU transformers to the 138 kV system. The connection from the generators to their associated GSU transformers is by isolated phase bus duct. Normal operating power for auxiliary equipment for each unit is derived from dedicated main auxiliary transformers, which are directly connected to their associated generator buses. The power for starting the units is presently derived from two RAT-rated 138 kV-2.4 kV. BR1 and BR2 share one RAT for startup and BR3 has a dedicated RAT.

2.5.3 Performance

Table 2.5-3 presents recent historical net generation, CF, EAF, and EFOR for the E.W. Brown Generating Station. The table also shows the industry averages for CF, EAF, and EFOR. Industry average data come from GADS provided by the NERC and are for units in the SERC and RFC NERC regions for the years 2000 to 2006. The industry averages are as reported for units between 100 and 125 MW for Unit 1, between 150 and 200 MW for Unit 2, and between 350 and 550 MW for Unit 3.

In general, the E.W. Brown Generating Station average EAF and EFOR for the years 2004 to 2007 were comparable to or better than industry averages. However, there were outage activities over the past 4 years that affected the EAF and EFOR of certain units. These events are listed below:

- In 2007, BR1 was down for the scheduled 2 month major steam turbine overhaul.
- BR3 was down in 2005 for a scheduled 2 month turbine major overhaul in the spring.
- BR3 experienced a breaker fire in 2005 that caused a forced outage event lasting approximately 3 months. The failed breaker associated with a high horsepower fan has since been moved to a separate electrical bus to reduce the load on that system, which was near its limit at the time. Since the event, EON has enhanced the station's breaker overhaul procedures with the maintenance provider to include more rigorous trip-timing and test requirements. BR3 further experienced unplanned outage events of more

than 200 hours in 2005 because of boiler tube leaks. EON was able to resolve the boiler tube leak problem and has plans to improve reliability of the boiler through condition assessment and replacement of boiler tubes. Boiler tube replacement projects are included in the planning period of 2008 to 2012 to improve boiler reliability.

Table 2.5-3
Historical Performance Data for E.W. Brown Generating Station Units 1, 2 and 3

	2004	2005	2006	2007	Average
Unit 1					
Net Generation (MWh)	568,432	563,532	480,534	493,483	526,495
Net Heat Rate (BTU/kWh)	10,980	11,091	11,254	11,124	11,106
Capacity Factor (%)	63.9	63.4	54.0	55.5	59.2
Industry Average CF (%)					*51.3*
Equivalent Availability Factor (%)	90.1	91.2	89.8	77.6	87.2
Industry Average EAF (%)					*84.4*
Equivalent Forced Outage Rate (%)	3.8	3.2	3.5	5.4	4.0
Industry Average EFOR (%)					*6.9*
Unit 2					
Net Generation (MWh)	971,532	1,075,007	956,008	1,013,933	1,004,120
Net Heat Rate (BTU/kWh)	10,215	10,079	10,252	10,352	10,222
Capacity Factor (%)	66.0	73.1	65.0	68.9	68.2
Industry Average CF (%)					*63.2*
Equivalent Availability Factor (%)	90.3	87.8	89.4	91.9	89.9
Industry Average EAF (%)					*86.3*
Equivalent Forced Outage Rate (%)	2.7	2.5	3.5	2.0	2.7
Industry Average EFOR (%)					*6.0*
Unit 3					
Net Generation (MWh)	2,246,620	1,584,997	2,031,288	2,396,909	2,064,954
Net Heat Rate (BTU/kWh)	10,512	10,526	10,447	10,282	10,434
CF (%)	59.5	42.0	53.8	63.5	54.7
Industry Average CF (%)					*57.4*
EAF (%)	85.9	54.4	88.8	85.0	78.5
Industry Average EAF (%)					*83.5*
EFOR (%)	1.2	32.3	4.0	2.9	10.1
Industry Average EFOR (%)					*6.7*

Based on interviews with plant personnel and a review of the documentation provided, unless otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget.

2.5.4 Operations and Maintenance

Black & Veatch reviewed the organization chart provided and noted that the management of the Brown and Tyrone stations is combined. The total (approved) staff dedicated to the E.W. Brown Generating Station is 135, with 3 vacancies (at the time the chart was printed). These numbers reflect a four (4) shift operating rotation and a maintenance complement inclusive of a dedicated outage coordinator.

The documents provided indicated that the E.W. Brown units have a very comprehensive program for operator training. This program encompasses initial qualification and continuous reassessment and refresher training. The materials appear to be of high quality and include detailed explanations of the purpose and function of all of the major systems.

As was the case with the training information, the data provided regarding the operating procedures was comprehensive and of high quality. The ease with which this information was produced and available for review would suggest it is also very accessible to the users in the plant. The actual procedure documents suggested that the program provides significant detail and explanation of exactly what is expected of the operator. The documents also have a clear indication of the procedure control and review process. The only issue that might be raised relative to the overall process has to do with the review of changes to the procedures. A truly comprehensive control process would incorporate review by several parties to ensure that any change addresses not only the control of the equipment, but also any potential impacts on the unit control design and safety, environmental concerns, safety, and engineering. These parties may be integrated in the document control process, but it was not obvious from the documents provided.

The Operating Plan also noted that the E.W. Brown Station is in the process of implementing a standardized maintenance planning process utilizing the Maximo CMMS. In this process, the bulk of the maintenance planning efforts will be transferred to maintenance planners. This will relieve the crew chiefs and supervisors from responsibility for many aspects of work planning. The information provided included detailed descriptions of their preventive maintenance tickets. These descriptions were broken down by systems and crews and included priority, crew size, and estimated duration. These appeared to be comprehensive and thorough.

The E.W. Brown units also utilize the formal PDM program administered through the corporate office. The information provided included copies of current reports to show depth and application of the program. This was a reasonably detailed example that used a color code to distinguish new problems versus issues that have previously been identified and are still being observed. The example report appeared to emphasize vibration, with little or no information provided with regard to the other three technologies.

The E.W. Brown Station Operating Plan suggested that the station is in the process of implementing the corporate guidelines for outage management. This effort was complemented with extensive data showing projects directly linked to known forced outage issues for both the steam plant and, separately, for the gas turbines. The current general planning cycle calls for an annual boiler outage (3 week duration) on each of the steam units and a major outage lasting 8 weeks every 7 years.

O&M Expenses

The historical O&M costs for all of the E.W. Brown Generating Station units are shown in Table 2.5-4.

Table 2.5-4
E.W. Brown Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$14,575	$18,254	$20,905	$19,331	$22,184
Other Cost of Services		$424	$859	$1,260	$1,088
Fuel Handling	$41,225	$1,256	$1,374	$1,440	$1,531
Below the Line	$627	$-271	$184	$80	$2,113
Total Controllable	$16,427	$19,663	23,322	$22,111	$26,916
Net Generation (GWH)	4,098	3,987	3,224	3,468	3,904
Controllable/MWh	$4.01	$4.93	7.23	$6.38	$6.89

2.5.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the station on July 17 and 18, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition with no signs of significant leakage of oil, water, or steam; corrosion damage; or other distress. Electrical rooms were clean and not used as storage for unrelated items. Battery rooms were locked and kept generally clean. The floor space in front of the switchgear was clear and open for operation, unless breaker maintenance was currently being performed. The control room and plant lighting were functioning.

The construction of the new FGD to scrub BR1, BR2, and BR3 was in progress at the time of the site visit. The new ash pond annex was observed to be complete; and Black & Veatch was informed that it was ready to start receiving ash.

Boilers

The impending fuel switch to Illinois Basin coal, associated with the commissioning of the new FGD, is expected to contribute to increased boiler slag, erosion damage, and coal mill performance issues. A fuel switch study is currently underway with the EON project engineering group. Recent boiler projects identified prior to the final results available of the fuel switch study include BR1 primary superheater top intermediate bank and reheat bank, BR2 reheater and inlet/outlet headers, and BR3 primary superheater. These planned boiler projects have been identified in anticipation of erosion issues associated with the impending fuel switch.

In 2007, the BR1 furnace (waterwall area) was fully scaffolded and a tube thickness survey was performed on every fifth tube of the furnace front, rear, left, and right walls. Minor corrosion was found on the front wall that should be closely monitored. There is some minor waterwall wastage at the upper burner elevations that is to be monitored, mostly because of soot blower erosion. Some erosion has been found recently in the BR1 reheater near the top of the outlet bank and top intermediate banks, and tube shields installed in 2007. EON capital plan includes select replacement of BR1 reheater components in 2012, in anticipation of additional erosion expected due to fuel switch associated with commissioning the new FGD.

In 2006, the BR2 exterior insulation on the boiler was found in fair to poor condition, and it was noted that the majority of the insulation is still asbestos. The boiler manufacturer representative recommended replacement of insulation on the boiler, including removal of all asbestos and inspection of the buckstay attachments to the tubes where several exterior leaks have occurred.

The BR2 boiler manufacturer has recommended that the station diligently pursue a fuel conversion study to better understand which components are at risk for design issues (such as convection pass clogging due to lateral spacing, reheater spacing design) as a result of conversion to higher sulfur coal once the new scrubber goes into service. EON project engineering is currently conducting this study. EON has identified the BR2 reheater (including inlet/outlet header) as requiring replacement. Metallographic examinations showed that the reheater outlet header had possible early stage creep damage at a longitudinal seam weld. EON plans to replace the reheat inlet and outlet headers in 2008/2009.

The BR3 primary superheater was found to have erosion damage during the 2008 inspection. Repairs and shielding were installed in 2008, and the boiler manufacturer recommended redesign of the baffling/screening in an attempt to reduce velocities and erosion in the front quarter of this component. The EON capital plan includes replacement/redesign of the BR3 superheater for 2010, in anticipation of additional erosion expected due to the fuel switch associated with commissioning the new FGD.

The upper arch that includes the rear waterwall screen tubes was found to have wall loss of up to 35 percent due to erosion. Erosion rate may increase due to fuel switch to high sulfur coal and expected increase in soot blowing.

Steam Turbines

In 1999, Westinghouse recommended that BR1 LP rotor be retired, based on rotor bore inspection results and vintage (1955) of the rotor. To get a second opinion, KU engaged a third party consultant who performed a probabilistic analysis and recommended a special overbore operation, including some bore surface grinding to remove some bore surface cracks. With this operation, the consultant determined that the rotor could be placed back in service for another 100 starts. Plant operators put the rotor in service in 1999. Again in 2005, Structural Integrity Associates (SI) was engaged by KU to determine the status of the rotor. They performed two analyses of the rotor. In the first analysis, they used Westinghouse bore ultrasonic 1999 test data and an assumed rotor material fracture toughness value of 40. The results of this analysis have allowed 225 starts since the return to service in 1999. The second analysis, which used more definitive fracture toughness value of 180 from actual rotor material testing, predicted that the rotor could undergo 1,000 additional starts. BR 1 had 104 starts from 1999 to 2007, with an average of 12 starts per year.

Upon review of the reports received from EON, Black & Veatch is of the opinion that these analytical analyses produced a very wide range of conclusions based on the assumptions that were used. Westinghouse used its data base and the vintage (1957) of the rotor to come up with the conclusion. Normally, OEMs are very conservative in their assessments. SI is quite well known and is a competent analytical organization. SI's recommendation may be more reliable than the OEM's. However, the conclusions from SI are based on two assumptions. First, the fracture toughness value does not change substantially along the rotor, and second, the maximum size of the crack is not more than 0.75 inch. These assumptions appear to be reasonable and conservative based on the fact that SI used the lowest value of the measured fracture toughness (180) and a conservative crack size (0.75 inch), whereas the maximum size of any crack measured in 1999 and 2005 was not more than 0.5 inch.

Black & Veatch agrees with SI's recommendations, but cautions that there is a slight risk of a rotor burst because of the following reasons:

- SI could not perform bore ultrasonic inspection at the more critical bottle bore section of the rotor because of dimples from prior grinding operation.
- The 1999 ultrasonic inspections show a very high density of indications in the bottle bore area. In this area, the cracks could link up and get bigger than the critical size.

Black & Veatch is of the opinion that it will be prudent for EON to replace the rotor with a new rotor in the long-term plan.

The BR1 HP/IP rotor bore examination was completed in 2007 by Siemens. Based upon the data taken from the bore examination, Siemens' calculations showed that, if the rotor were to be operated within the specific recommendations for a bored rotor, it would be acceptable to run the rotor for another 10 years from 2007. Siemens recommended that if the rotor was to be run for many more years beyond the 10 year interval, it would require material testing to be performed to assess creep damage to the rotor material.

The BR2 steam turbine is scheduled for major overhaul outage in 2009. The capital plan for the 2009 BR2 overhaul is to replace the steam seals (restore design seal clearances) and the LP turbine L-1 blade rows. These particular repairs were based upon the results of previous major overhaul repairs (1994, 2001, and others) and based upon reported repairs made in 2007 during a minor overhaul. The present capital budget for these repairs is $986,000.

The BR3 LP rotor was replaced in 1997 as an output improvement upgrade of capacity up to 446 MW from 409 MW. This project involved additional capacity for the unit and is reported to be currently in final stages of settlement of NSR NOV proceedings. In 1997, the BR3 generator had its retaining rings replaced with nonmagnetic type rings. In addition, the generator rotor was completely re-wound. In the fall of 2005, the exciter rotor for the BR3 generator was refurbished with a replacement (seed) exciter rotor that was purchased from Siemens, as a result of inspection findings in spring 2005. The nameplate kVA rating of the BR3 generator has not changed from the original design according to the Siemens-Westinghouse design data reviewed by Black & Veatch.

The BR3 HP-IP rotor is presently planned for replacement in 2012, for a cost of $17,967,000 in order to achieve improved efficiency/capacity. Siemens performed an

HP-IP rotor bore examination on BR3 in 2005. Based on the stress evaluations performed, it was determined that the life of the rotor was well above 3,000 speed cycles, assuming that startup and operation procedures were followed. Siemens recommended that the rotor be re-inspected after 10 years of operation.

Balance-of-Plant

The low NO_x burners on the units have kept the units within their respective NO_x emissions limits for 2007. New emission regulations that are in line with the vacated CAIR may require additional NO_x controls to be installed, to achieve targeted emission allowances apportioned to the plant. Past reliability of the CEMS has been within expected EPA standards and should continue with maintenance levels as required. Some analyzers may be required to be replaced that were noted as still being of the original installation in the mid 1990s. The ESPs did not appear to have caused any major reliability or performance issues in the recent past, as represented by reported particulate and opacity emissions compliance and forced outage records. There is no reason to assume that, with the same level of maintenance, this performance should not continue. No significant building structure issues were indicated by plant operating staff during the site visit. The station did not report any issues relative to system air, and no forced outage events were reported.

2.5.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.5. From the information provided, the existing E.W. Brown Station appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON was issued two NOVs in 2006 for performing "major capital expenditures for Unit 3 at the E.W. Brown Generating Station to increase electrical production from the unit to 446 MW." These NOVs concerned the fact that the facility failed to obtain the appropriate permits (Prevention of Significant Deterioration and Title V) and follow certain other regulatory programs, such as the New Source Performance Standards (NSPS) prior to executing the changes. The 2008 to 2012

Operating Plan indicates that EON is currently in NSR proceedings, including responding to EPA/Department of Justice (DOJ) requests, settlement negotiations, and discovery. Documentation further indicates that along with other potential new limits on the facility, as part of the settlement, the installation of the SCR on Unit 3 may be moved up from 2015 to 2012. Follow-up correspondence concerning the progress of the NOVs was not available for review.

- Similar to the above issue, company planning documents indicate that several major projects, including the installation of a common FGD system for BR1, BR2, and BR3, have either recently been completed or are in planning stages. A submittal letter for the wet FGD application (without supporting information) and an approval letter from the KDAQ (both dated in March 2005) were available for review. The approval letter from the KDAQ indicated that the minor permit modification for the project was classified as "environmentally beneficial" or otherwise known as a PCP. However, no additional information was found indicating that these changes at E.W. Brown Station underwent the necessary permitting review and met the applicable requirements in light of the vacature of the NSR PCP exemption on June 24, 2005. This would also include current or anticipated changes in material handling (fuel and byproduct) due to the addition of the FGD system. However, when notified of this issue, EON indicated that the KDAQ does not consider the vacature a concern for its FGD projects because the coincidental increases of particulate from the associated material handling systems were included in the application and were less than the applicable significance level.
- EON has submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with permit conditions (and other regulatory programs such as acid rain and risk management planning), with the exception of the following items:
  - BR1, BR2, and BR3 were in continuous compliance, except for numerous opacity and opacity trigger levels throughout the year. The report indicated that stack tests were not triggered. The opacity exceedances were mainly due to startups, shutdowns, load changes, blowing, precipitator trouble, and unit trip/upset. The SO_2 exceedances were due to fuel problems.

Other

- The facility has some sizable oil spills in its history. Enforcement action was taken by EPA in 2005 regarding the October 2, 1999 spill of 38,000 gallons of diesel fuel into Cedar Branch Creek. Other documented spills include the September 24, 2006 reportable spill quantity of 75 gallons and a November 30, 2007 spill quantity of 75 gallons. The 2006 and 2007 spills were documented as being cleaned up, with contaminated soil removed and disposed of.

2.5.7 Key Findings

- E.W. Brown Generating Station appears to have the required environmental permits in place and to be operating in substantial compliance with permit and regulatory requirements.
- E.W. Brown Generating Station (BR1, BR2, and BR3) draws raw water from Herrington Lake, the reservoir impounded behind Dix Dam. A study released in draft form in April of 2008 concluded that the present leakage rate through the dam is not considered alarming, and the structural integrity of the dam is considered intact. At present, the current EON budget includes a $2.2 million project to re-caulk the face slab of Dix Dam, which is scheduled for 2011.
- There is a pending litigation associated with NSR for Unit 3 with regard to the extra generating capacity provided to the unit by a new LP turbine replacement and HP/IP turbine enhancement. No resolution to this litigation has been reached at this time. The potential impact of this issue could be a resolution that would require additional emissions controls being applied to the unit.
- The BR3 turbine generator experiences higher than normal vibration due to a potential HP/IP imbalance or possibly to an LP rotor to generator alignment issue. EON is aware of this issue and has planned capital projects, such as replacement of the HP/IP rotor, to resolve this issue, as well as increasing the efficiency and capacity of the unit.

2.6 Green River Generating Station

2.6.1 Introduction

The Green River Generating Station, as illustrated on Figure 2.6-1, is located 3 miles north of Central City in Muhlenberg County. The property is bounded on the north by coal strip mines, on the southeast by the Green River, and on the south and west by rolling hills with a few residences. Table 2.6-1 provides a summary of the Green River Generating Station plant facts.

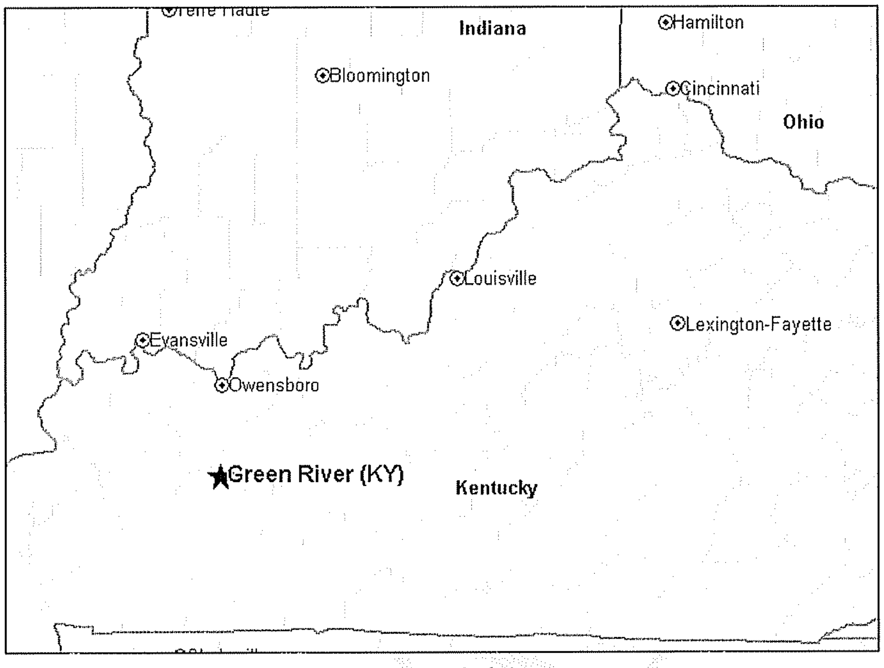

Figure 2.6-1
Green River Generating Station Location

Table 2.6-1
Green River Generating Station Fact Sheet

Category	Data	Category	Data
Location:	Central City, KY	**Market Area:**	Midwest
Nominal Capacity:	168 MW net	**Off-Take:**	EON network customers
Ownership:	KU - 100%	**Electric Interconnection:**	Green River 138 kV Substation
Fuel:	Coal	**Fuel Supply:**	Contract and spot
Type:	Pulverized coal fired, sub-critical steam generators	**COD:**	April 1, 1954 (Unit 3) July 1, 1959 (Unit 4)
Equipment:	2 x B&W boilers and 2 x Westinghouse steam turbines	**Operator:**	KU

Notes:
1. Capacity represents 100 percent of average (winter, summer) net electrical output.

The station is a four unit, coal fired electric generating station with a total nameplate capacity of 189 MW gross (168 MW net). Units 3 (GR3) and 4 (GR4) are pulverized coal fired generating units. Units 1 (GR1) and 2 (GR2) were decommissioned in January 2002 and are, therefore, not included within this review.

The station is owned by KU, and its electrical interconnection is through the Green River 138 kV Substation. The units are designated as network resource generating units on the EON transmission system. The full load output from these units can be used to serve the network customers interconnected to EON transmission system.

Coal is delivered to the site via trucks from mines in Kentucky and Illinois. Condenser cooling water is drawn from the Green River in a once-through configuration.

2.6.2 Plant Description and Design

Siting and Real Estate

The Green River Generating Station is located 3 miles north of Central City in Muhlenberg County. The property is bounded on the north by coal strip mines, on the southeast by the Green River, and on the south and west by rolling hills with a few residences. The elevation at the plant averages 400 feet above mean sea level. The water table in the alluvial aquifer underlying the plant is estimated to occur at approximately 25 feet below land surface, based on interpretation of topographic contours. The plant is accessible via US Highway 431 just north of Central City, and also via the Green River. An elevation view of the plant is shown on Figure 2.6-2.

Figure 2.6-2
Green River Generating Station

Equipment

GR3 and GR4 are pulverized coal fired generating units with Westinghouse turbine generators, for a total plant generation of 189 MW gross. Depending on the company's load requirement, these units either serve native load on higher load demand days or generate for sales opportunities if their dispatch cost remains below the sale price. The major plant equipment is listed in Table 2.6-2.

Boilers

GR3 has a natural circulation B&W pulverized coal boiler (Boiler 4) rated for 660,000 lb/h of steam at 875 psig and 905° F. GR4 has a natural circulation B&W pulverized coal boiler (Boiler 5) rated for 750,000 lb/h of steam at 1,525 psig and 1,000 F with 1,000 F reheat. Both GR3 and GR4 boilers fire bituminous coal from mines in Kentucky and Illinois. Based on available recent coal data, the as-received heating value is in the range of 10,900 Btu/lbm to 12,100 Btu/lbm, with approximately 9 percent ash and 2.5 percent sulfur.

Table 2.6-2
Green River Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Boiler	Unit 3	1	Natural circulation B&W pulverized coal boiler (Boiler 4) rated for 660,000 lb/h of steam at 875 psig and 905° F
	Unit 4	1	Natural circulation B&W pulverized coal boiler (Boiler 5) rated for 750,000 lb/h of steam at 1,525 psig and 1,000° F with 1,000° F reheat
Steam Turbine	Unit 3	1	Westinghouse tandem compound turbine rated for 850 psig and 900° F steam, with a two-pass radial flow condenser and hydrogen-cooled generator rated for 74 MW gross average
	Unit 4	1	Westinghouse tandem compound turbine rated for 1450 psig and 1,000° F and 1,000° F reheat, with a two-pass condenser and hydrogen-cooled generator rated for 106 MW gross avg
Draft System	Unit 3	2	Westinghouse mechanical draft FD fans with inlet vane control
		2	Air heaters
		2	Westinghouse mechanical draft ID fans with fluid drives
	Unit 4	2	American blower mechanical draft FD fans with inlet vane control (50 percent nom.)
		2	Air heaters
		1	American Blower mechanical draft gas recirculation fan with inlet vane control
		2	American Blower mechanical draft ID fans with fluid drives
Condenser	Unit 3	1	Two-pass vacuum condenser
	Unit 4	1	Two-pass vacuum condenser
Circulating Water System	Unit 3	2	Circulating water pumps
		1	Once-through cooling system, Green River
	Unit 4	2	Circulating water pumps
		1	Once-through cooling system, Green River
Generator	Unit 3	1	Westinghouse, 75 MW, 13.8 kV
	Unit 4	1	Westinghouse,133.7 MVA, 13.8 kV, 0.85 PF at 30 psi H_2

Table 2.6-2 (Continued)
Green River Generating Station Major Equipment

Description	Unit	Quantity	Characteristics
Control Systems	Unit 3	1	Bailey Infi-90, installed in 1999
	Unit 4	1	Hybrid DCS solution encompassing all aspects of boiler control and most subsystems
Condensate and Feedwater Systems	Unit 3	2	Westinghouse vertical multistage axial condensate pumps (50 percent nom.)
		2	Ingersoll-Rand centrifugal 5 stage boiler feed pumps (50 percent nom.)
	Unit 4	2	Vertical pit type, multistage mixed flow condensate pumps (50 percent nom.)
		2	Ingersoll-Rand centrifugal, vertically split, barrel, 5-stage boiler feed pumps with GE 1,500 hp motor drivers (50 percent nom.)
Flue Gas Treatment	Unit 3	1	Cold side ESP retrofit in 1973 Low NO_x burner combustion controls, installed in 2002
	Unit 4	1	Cold side ESP retrofit in 1975. Low NO_x burner combustion controls, installed in 1995
Electrical System	Unit 3	1	13.2kV – 138kV, 80MVA
	Unit 4	1	Westinghouse, 13.2-138kV, 120MVA

Steam Turbine Generators

The station has two Westinghouse steam turbine generators. The GR3 steam turbine generator is a tandem compound turbine rated for 850 psig and 900° F steam, with a two-pass radial flow condenser and hydrogen-cooled generator rated for 75 MW and 85 percent power factor. GR4 STG is a tandem compound turbine rated for 1,450 psig, 1,000° F reheat, with a two-pass condenser and hydrogen-cooled generator rated for 113.6 MW and 85 percent power factor.

Emissions Systems

Both units are equipped with low NO_x burners, ESPs, and CEMS.

Both boilers have low NO_x burner combustion controls, which were installed on Unit 3 in 2002 and Unit 4 in 1995. Both units have cold ESPs that were supplied as part of the retrofit to the units in 1974 and 1975. The ESPs have emission limit ratings of 0.22 lb/MBtu based on a 3 hour average or a 40 percent opacity based on a 6 minute average, except that a maximum of 60 percent opacity is allowed for a period or aggregate of periods of not more than 6 minutes in any 60 minutes.

An existing extractive dilution type CEMS is installed on each unit for measuring NO_x, SO_2, CO_2, and stack flow. A Lear Siegler opacity monitor is installed in the stack.

The CEMS system has already been upgraded to StackVision, the latest programming available from ESC, the data acquisition and handling system OEM. This upgrade should allow the system to meet future reporting requirements.

Control Systems

The GR4 boiler controls have been replaced with a modern, Hybrid DCS solution encompassing all aspects of boiler control and most subsystems. The existing Bailey Infi-90 DCS system for GR3 will be expanded to include control of low voltage motors in a 2010 project. The coal yard/tripper control system has been replaced with a modern programmable logic controller (PLC).

Auxiliary Systems

The site has two ash ponds, a coal runoff pond, and a non-active scrubber solids pond. Bottom ash and fly ash are conveyed by water to the first ash pond. This pond acts as the primary solids retention pond. The decanted water overflows though a concrete weir. Further treatment is provided by a silt screen and pH adjustment prior to the weir. The water is routed to the second pond where it has additional retention time for solids removal. The overflow from this pond is directed to the river. A silt screen and final pH adjustment are maintained at this point for environmental compliance.

GR3 condensate and feedwater systems include two Westinghouse vertical multistage axial condensate pumps (50 percent nom.) and two Ingersoll-Rand centrifugal five-stage boiler feed pumps (50 percent nom.). GR4 condensate and feedwater systems include two vertical pit type, multistage mixed flow condensate pumps (50 percent nom.) and two Ingersoll-Rand centrifugal, vertically split, barrel, five-stage boiler feed pumps with GE 1,500 hp motor drivers (50 percent nom.).

Fuel Supply

Coal is delivered to the site via trucks from mines in Kentucky and Illinois. Barge unloading equipment exists, but has been abandoned. Condenser cooling water is drawn from the Green River in a once-through configuration.

The plant access road is off of US Highway 431 approximately 3 miles north of Central City in Muhlenberg County. The access road is narrow and winds its way down the grade from the highway to the plant. Coal deliveries can require as many as 45 trucks per day to keep the units fueled and add surplus to the coal pile. The entrance road is scheduled for resurfacing in 2012 and 2013.

Water and Wastewater

All water serving the plant is withdrawn by one intake structure located in the Green River. Most of this water is used for once-through cooling water and is returned through a discharge canal downstream of the intake point.

Drinking water for most residences within 3 miles of the Green River Plant is supplied by the Central City Municipal Water System, which obtains water from a surface intake on the Green River approximately 3 miles upstream from the Green River Generating Station.

The sewage treatment plant is located to the northeast of the GR1 main building and has received maintenance at various times during the installation lifetime.

Electrical and Interconnection

The electrical power output of each unit is delivered from the two 13.8 kV generators through the GSU transformers to provide both load and voltage support for the 138 kV system.

2.6.3 Performance

Table 2.6-3 presents the historical net generation, CF, EAF, and EFOR for the Green River Generating Station. The table also shows the industry averages for CF, EAF, and EFOR. Industry average data come from GADS provided by the NERC and are for units in the SERC and RFC NERC regions for the years 2000 to 2006. The industry averages are as reported for units between 50 and 100 MW for Unit 3, and between 100 and 125 MW for Unit 4.

In general, the station average EAF and EFOR for the years 2004 to 2007 were comparable to industry averages. However, there were outage activities over the past 4 years that affected the EAF and EFOR of certain units. These events are listed below:

- GR4 was down in 2005 for the scheduled annual 3 week boiler inspection in the spring.
- GR4 was also down subsequently in the summer of 2005 for more than 3 months because of HP turbine damage. The GR4 HP turbine was damaged by an extreme temperature excursion resulting from the loss of attemperator control in 2005. The event was classified as operator error that resulted in more than 3 months of forced outage hours. Major repairs included replacement of the first three rows of turbine blades, seals, and packing, and the inlet valves. Measures taken to prevent further water induction issues included the installation of automated attemperation block valves, steam traps on the

Table 2.6-3
Historical Performance Data for Green River Generating Station 2 Units

	2004	2005	2006	2007	Average
Unit 3					
Net Generation (MWh)	334,589	336,673	206,046	420,678	324,497
Net Heat Rate (BTU/kWh)	12,996	12,945	12,700	12,304	12,640
Capacity Factor (%)	55.0	55.3	33.8	69.1	*53.3*
Industry Average CF (%)					*45.1*
Equivalent Availability Factor (%)	88.3	86.4	87.4	94.8	*89.2*
Industry Average EAF (%)					*86.1*
Equivalent Forced Outage Rate (%)	5.5	8.4	6.0	3.6	*5.9*
Industry Average EFOR (%)					*7.9*
Unit 4					
Net Generation (MWh)	464,247	338,730	433,665	576,042	453,171
Net Heat Rate (BTU/kWh)	11,870	11,546	11,348	11,153	11,457
Capacity Factor (%)	53.8	39.3	50.3	66.8	52.5
Industry Average CF (%)					*51.3*
Equivalent Availability Factor (%)	80.8	53.6	85.9	86.8	76.8
Industry Average EAF (%)					*84.4*
Equivalent Forced Outage Rate (%)	6.7	45.3	6.0	4.8	15.7
Industry Average EFOR (%)					*6.9*

- turbine extraction steam lines, and feedwater heater level trips. However, the extraction lines still have manual isolation valves. Black & Veatch is of the opinion that these should be replaced with automatic trip valves to improve the system reliability. Currently, the capital plan for period 2008-2012 does not include spending to fully upgrade the turbine water induction measures.
- GR4 also experienced a 1 month forced outage event in 2005 due to boiler tube failure because of corrosion fatigue damage, which caused other tube leaks and blew a section of boiler casing. Subsequently, the boiler manufacturer provided a report detailing the areas most susceptible to this type of damage. GR4 personnel inspected all of the water circuit tubing in 2007 during a planned outage, and replaced tubing sections as necessary, based on appropriate visual testing criteria. The same inspection methods and scopes are planned for GR3 in 2009.

Based on interviews with plant personnel and a review of the documentation provided, unless otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget.

2.6.4 Operations and Maintenance

Operations

With respect to the Green River Generating Station, Black & Veatch reviewed the organization charts (table) provided and discussed the staffing organization during the site visits. This plant operates with a reasonably lean organization that would appear appropriate given the smaller units and especially units that lack the extensive air quality control systems that are common to the larger units. The station does not appear to have a dedicated outage manager, suggesting outage responsibilities are not the exclusive responsibility of one individual. This is in contrast to most all the other EON units.

Black & Veatch reviewed the Green River Operating Plan. With respect to plant operations, the plan noted the employees have averaged receiving more than the targeted 40 hours of training per year. This was notable as a response to issues noted by UMS in the best practices review. The Operating Plan also noted that the plant has initiated efforts based on EON programs for Outage Planning and the Boiler Circuit Maintenance Strategy. Both programs have been initiated and appear to be improvements over past practice.

The station provided a Business Continuity Plan (BCP) for review. The BCP described the steps to be taken and the responsibilities assigned in the event of an emergency or disaster of some sort. This document provided clear direction to the plant management of their responsibilities and would also aid EON's system by knowing who to contact and how they plan to restore or continue operations in the event of an emergency.

The review of the training documents provided indicates a reasonable program for operators. The system descriptions were reasonably well written but not as structured as Black & Veatch would recommend or was the case with most of the other EON units. There were drawings and/or control system screen shots to compliment the written documents. The exams reviewed were relatively short and could be memorized. There also was not indication of different requirements for different positions unless they focused only the systems. Overall, this training program appears to meet the minimum functional requirements.

The Green River Generating Station, like all the other EON assets, utilizes Maximo for maintenance planning. There were only a very limited number of maintenance related documents available for review. Those that were provided indicated the plant has a good focus on understanding which particular systems are critical to unit operation and reliability. Maintenance and condition assessment activities have concentrated on those critical systems.

No specific information regarding the preventive maintenance program established for Green River Generating Station was available for review.

PDM documentation provided suggests that Green River Generating Station is somewhat dependent on other stations for equipment to implement the station PDM program, with the exception of vibration equipment, which is available at the Green River Generating Station. Through efforts coordinated with the other plants and generation engineering, the plant addresses its PDM needs. There is a substantial body of information available through the EON WAN using the Emerson CSI PDM software. The plant has provided PDM awareness training to station personnel and condition assessment technology specific training is planned in order to have in-house personnel available who understand vibration data collection, oil sampling/analysis, lubrication, thermography, and rotor bar testing.

Black & Veatch assumes that Green River Generating Station is following and/or implementing the functional aspects of the EON Outage Management guidelines as much as possible.

O&M Expenses

The historical O&M costs for the Green River Generating Station units are shown in Table 2.6-4.

Table 2.6-4
Green River Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$10,400	$7,665	$9,209	$8,566	$9,192
Other Cost of Services		$650	$323	$407	$483
Fuel Handling	$445	$441	$609	$745	$540
Below the Line	$11	$10	$10	$6	$7
Total Controllable	$10,856	$8,766	$10,151	$9,724	$10,222
Net Generation (GWH)	669	799	675	640	997
Controllable/MWh	$16.22	$10.97	$15.03	$15.20	$10.26

2.6.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the facility on July 22, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition with no signs of significant leakage of oil or steam, corrosion damage, or other distress. Significant water leakage from the service water screen shaft seals was observed, and this was reported to be planned for maintenance as part of the engineering study for the overall service water system. The bottom ash hoppers appeared to be in very good condition; no water leaks were observed. Plant management maintains good control over asbestos insulation replacements; insulation that has been replaced is clearly marked as being asbestos free.

Some degradation of the building roofs and tuck pointing of the brick walls was observed. This is considered a minor issue, but should be addressed in the future. The existence of abandoned FGD equipment and open tanks from previously retired units provides areas for significant storm water to accumulate and remain as open stagnant pools of water that may present health risks to plant personnel. The undisturbed state of other equipment and facilities from the retired and abandoned units does not appear to present risks to the remaining operating units.

Boilers

GR3 has one natural circulation B&W pulverized coal boiler rated for 660,000 lb/h of steam at 875 psig and 905° F. GR4 has one natural circulation B&W pulverized coal boiler rated for 750,000 lb/h of steam at 1,525 psig and 1,000° F with 1,000° F reheat. The GR3 and GR4 boilers were retrofitted with low NO_x burners in 1995 and 2002, respectively. No slagging or fouling issues have been reported on the boilers. The GR3 oil igniter has caused outages in the recent past; it is scheduled for replacement in 2009. GR3 and GR4 personnel expect that the remainder of the ignition oil storage and pumping systems will only require normal cleaning and inspections.

Steam Turbines

Turbine inspections are generally scheduled every 7 years. The last GR3 turbine inspection was in 2003, and the next two are scheduled for the fall of 2009 and 2016. Review of the 2003 outage report found appropriate inspections and repairs, including restoration of seal clearances, valves, and bearings. The first row of impulse blading was replaced during the outage.

Review of the GR4 2003 outage report found typical inspections and repairs, including restoration of seal clearances, valves, and bearings. The major activities performed during the outage included repair of eroded nozzle block partitions and NDE boresonic inspection of the HP turbine rotor. The HP rotor boresonic inspection found no indications or anomalies.

Balance-of-Plant

The plant building and support systems are nearing a point where major repairs may be required to extend their life. The brick wall mortar joints would need to be tuck pointed to maintain the integrity of the walls and reduce rain water leakage through the walls. Building roof repairs using rubber roofing materials are being scheduled in 2009. Additional roof repairs are being scheduled in the 2014/2015 time frame.

The GR4 boiler controls have been replaced with a modern, Hybrid DCS solution encompassing all aspects of boiler control and most subsystems. The coal yard/tripper control system has been replaced with a modern PLC solution. Long-term performance and flexibility of these systems is expected.

No substantial exceedances or outages due to opacity were noted for the last 3 years. The CEMS data submitted to the EPA or state regulators indicated that the system has high reliability and meets EPA guidelines.

Ash removal from the pond for beneficial reuse is an ongoing yearly project. Disposal of fly ash and bottom ash will be an ongoing issue for this unit due to the limited disposal capacity onsite. Pond capacity currently is about 2.5 years. This is being addressed by delivering ash for local beneficial reuse projects, which increases the ash handling O&M costs. The current customer will extend the life an additional 2 years to 2013, and plant management is working with another potential customer that will extend the life of the ponds several more years. If local beneficial reuse projects cannot be identified, costs of ash disposal will significantly increase. While ash removal is budgeted through 2013, the higher operating costs for these units will continue to need to be evaluated for viability of continued operations.

2.6.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.6. From information provided, the existing Green River Generating Station appears to have in place the required environmental permits and appears to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with their permit conditions, with the exception of a few items noted below:
  - The report indicates that Unit 3 and Unit 4 had 129 and 63 opacity exceedances, respectively, greater than their 20 percent permit limit, due to unit upset, load change, or soot blowing, and unit startup. Additionally, on August 1, 2006, the station received a NOV due to Unit 4 opacity violations. The opacity limit was noted as 40 percent, but the current operating permit, issued after this period, indicates the opacity limit of 20 percent. This limit may have been rescinded, as indicated in an internal EON email, due to timing of correspondence between the KDAQ and the station. Opacity exceedances may be an ongoing issue for this station.

Other

- As observed during the site visit by Black & Veatch, adequate long-term options for disposal and storage of combustion products is an important consideration for the Green River Generating Station. Pond capacity currently is estimated at about 2.5 years. This issue is being addressed by delivering ash for local beneficial reuse projects. The current customer will extend the life of the ponds an additional 2 years to 2013, and plant management is working with another customer on plans that will extend the life of the ponds several more years. If local beneficial reuse projects cannot be continued to be identified as in the past, the cost of ash disposal will significantly increase.
- Green River Station had two reported spill events in 2005. An estimated 1,000 gallon spill of oil from a 500,000 gallon tank resulted in removal of the tank and site remediation. An April 20, 2005, letter from the Kentucky Department of Environmental Protection (KDEP) noted that no further action is needed. Another spill in 2005 from a transformer reportedly hit by lightning was reported on August 14, 2005. A follow-up inspection by KDEP on December 21, 2005, and an email from Roger Medina of EON to KDEP on December 21, 2005, indicated that results of spill cleanup were satisfactory.

2.6.7 Key Findings

- Green River Generating Station appears to have the required environmental permits in place and to be operating in substantial compliance with permit and regulatory requirements.
- Because of its age and size, the facility has been challenged to meet its forced outage rate goal in the past few years because of capital budget reduction and a relatively flat O&M budget. The plant building and support systems are nearing a point where major repairs may be required to extend their life. Plant employees continue to consider other job opportunities because of the limited life expectancy of the plant.
- EON has recently increased the capital budget for the facility to meet integrated resource planning requirements to ensure operation until at least 2018.
- With the vacature of the CAIR and CAMR, this facility is now at greater risk for new AQC upgrade/retrofits, depending on the specific regulations that may replace the CAIR and CAMR. If a new emission trading scheme is not enacted, the coasts for required AQC retrofits, to meet the Hg MACT alone, may pose a significant challenge to the continued operation of these units.

2.7 Tyrone Generating Station

2.7.1 Introduction

The Tyrone Generating Station, as illustrated on Figure 2.7-1, is located in Woodford County, Kentucky. The Tyrone Generating Station includes a single operating coal fired electric generating unit with a total summer net declared capacity of 75 MW. Tyrone Generating Station Unit 3 (TY3) was placed in service in 1953. Table 2.7-1 provides a summary of the Tyrone Generating Station plant facts.

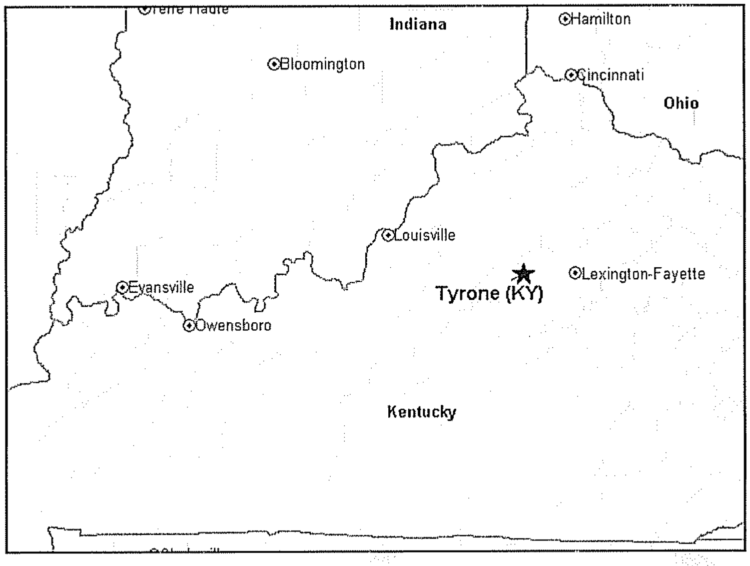

Figure 2.7-1
Tyrone Generating Station Location

Table 2.7-1
Tyrone Generating Station Fact Sheet

Category	Data	Category	Data
Location:	Lawrenceburg, KY	**Market Area:**	Midwest
Nominal Capacity:	72.5 MW net	**Off-Take:**	EON network customers
Ownership:	KU - 100%	**Electric Interconnection:**	Tyrone 69 kV Substation
Fuel:	Coal	**Fuel Supply:**	Little Elk mine (Perry County)
Type:	Pulverized coal fired, sub-critical steam generators	**COD:**	July 1, 1953 (Unit 3)
Equipment:	1 x B&W boiler, and 1 x Westinghouse steam turbines	**Operator:**	KU

Notes:
1. Capacity represents 100 percent of average (winter, summer) net electrical output.

2.7.2 Plant Description and Design

Siting and Real Estate

The Tyrone Generating Station, as shown on Figure 2.7-2, is located between Tyrone and Lawrenceburg, alongside Highway 62, in Woodford County, Kentucky. The station is located immediately across the Kentucky River from the Wild Turkey Distillery.

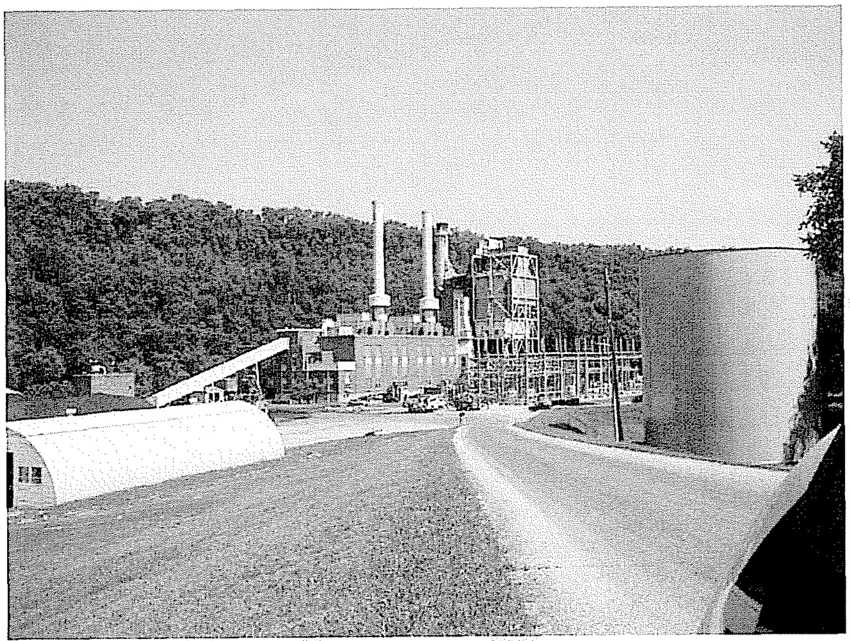

Figure 2.7-2
Tyrone Generating Station

Equipment

The Tyrone Generating Station includes a single operating coal fired electric generating unit with a total summer net declared capacity of 75 MW. The Tyrone Generating Station major equipment is listed in Table 2.7-2.

Table 2.7-2
Tyrone Generating Station Unit 3 Major Equipment

Description	Quantity	Characteristics
Boiler	1	B&W wall fired, balanced draft type boiler originally designed to fire high sulfur Muhlenberg Kentucky bituminous coal, rated for 660,000 lb/h of steam at 875 psig and 905° F
Steam Turbine	1	Westinghouse single-flow HP, nonreheat, tandem compound, dual flow LP turbine, with two-pass condenser and hydrogen cooled generator rated for 75 MW gross average
Draft System	2 4 1	Westinghouse FD fans with inlet damper control Model DE-2 straight line air heaters Westinghouse ID fans with variable speed hydraulic couplings, and 700 hp motors
Condenser	1	Two-pass vacuum condenser
Circulating Water System	2 1	Circulating water pumps Once-through cooling system, Kentucky River
Generator	1	Westinghouse, 75 MW, 13.8 kV, hydrogen cooled
Control Systems	1	Hybrid DCS solution encompassing all aspects of boiler control and most subsystems
Condensate and Feedwater Systems	2 2	Westinghouse vertical multistage axial condensate pumps (50 percent nom.) Ingersoll-Rand centrifugal, 10-stage barrel type boiler feed pumps with fluid drives (50 percent nom.)
Flue Gas Treatment	1	Cold side ESP retrofit in 1974 Low NO_x burner combustion controls installed in 2001
Electrical System	1	GE, 13.2 kV – 69 kV, 48/60/80 MVA (original rating)

Boiler

TY3 is a B&W wall-fired steam generator designed for Muhlenberg Kentucky bituminous high sulfur coal. The unit was designed to deliver 660,000 lb/h maximum continuous steam flow at 875 psig and 905° F.

Steam Turbine Generator

The steam turbine generator is a Westinghouse single-flow HP, non-reheat, tandem compound, dual flow LP turbine, with two-pass condenser and hydrogen-cooled generator rated for 75 MW.

Emissions Systems

A cold-side ESP was supplied as part of retrofit to the unit in 1974. The particulate emissions shall not exceed 0.22 lb/MBtu based on 3 hour average or a 40 percent opacity based on a 6 minute average, except that a maximum of 60 percent opacity is allowed for a period or aggregate of periods of not more than 6 minutes in any 60 minutes. New automatic voltage controllers were installed in 2004.

Low NO_x burner combustion controls, which were installed in 2001, are the only NO_x control measures installed on this unit. No specific Hg emissions controls currently exist on this unit. With the existing ESP as the only air quality control equipment and the firing of eastern bituminous fuel, Hg control on this unit is likely limited to a low level. The potential for higher levels of Hg control with the existing configuration may be provided if the high level of carbon provided by the high ash loss on ignition (LOI) values that exist on this unit serves to provide higher Hg removal, much like activated carbon injection. It is uncertain if this unit could meet the compliance requirements of maximum available control technology (MACT) and specific Hg testing, and a MACT study for this unit would need to verify if additional controls are required.

Auxiliary Systems

The plant creates approximately 50,000 cubic yards of ash per year of operation. The existing ash pond has a capacity of 80,000 cubic yards. Fly ash and bottom ash are both sluiced to the existing ash pond. The ash pond at the site is essentially full, and the plant excavates the ash, stacks it out to dewater, and then trucks it off site. In recent years, the plant has been successful with locating beneficial reuse projects.

TY3 receives pulverized coal from four B&E EL-64 pulverizer mills. The recent upgrade of the original equipment to the EL series in the last several years was completed as part of the capital budget for the Tyrone Generating Station.

Fuel Supply

Coal is delivered only by truck to the Tyrone Generating Station. When the plant is running, it burns 500 to 600 tons per day of coal. The coal is carried by 15 to 25 trucks. The trucks come from 100 to 150 miles away. The coal burned at the plant was noted to be an exceptionally low sulfur Eastern coal (1.8 pounds of sulfur per million pounds). This coal is very select and can only be obtained from limited source mines. At present, the plant has a 3 year contract with the Little Elk mine in Perry County for coal supply.

The coal is dumped in the coal yard either directly over the truck reclaim hopper or into the coal pile. The coal pile has a second reclaim hopper beneath it. This allows coal to be forwarded to the boiler either directly from the truck or from the coal pile reclaim. From reclaim, the conveyor carries the coal to the crusher house, and then there is an additional conveyor to carry the coal to the bunkers. The Tyrone Generating Station does not have any coal blending facilities.

Water and Wastewater

Water is drawn out of the Kentucky River through an intake structure located at the riverside. There are two screens and two 300 hp, 27,500 gallons per minute circulating water pumps to draw water from the river. This water is used for the Unit 3 steam turbine condenser once-through cooling system and other process water needs. Discharge from process water is to the circulating water flume discharging into the Kentucky River on the south side of the site. The Tyrone Generating Station uses city water from Tyrone for potable water.

The plant has a small sewage treatment plant onsite. It was reported that this plant does not function well because of insufficient flow and occasional accidents killing the active bacteria. The plant is planning to close this sewage treatment plant and install a holding tank.

There are two permitted outfalls at the plant: the circulating water outfall and the ash pond outfall. There are two drainage discharge points from the coal pile, both which are then directed to the ash pond. The ash pond discharges to the Kentucky River.

Electrical and Interconnection

The electrical power output from TY3 generator is delivered to the EON 69 kV transmission system through the Tyrone 69 kV Substation. The TY3 GSU transformer has a rating of 13.2 kV – 69 kV, 48/60/80 MVA and was manufactured by GE. The connection from the generator to the associated GSU transformer is by isolated phase bus duct.

2.7.3 Performance

Table 2.7-3 shows the historical net generation, CF, EAF, and EFOR for Tyrone Generating Station Unit 3. The table also shows the industry averages for CF, EAF, and EFOR. Industry average data come from GADS provided by the NERC and are for units in the SERC and RFC NERC regions for years 2000 to 2006. The industry averages are as reported for units between 50 and 100 MW.

Table 2.7-3
Historical Performance Data for Tyrone Generating Station Unit 3

	2004	2005	2006	2007	Average
Net Generation (MWh)	238,303	355,762	253,848	390,188	309,525
Net Heat Rate (BTU/kWh)	13,075	12,871	12,806	12,858	12,893
Capacity Factor (%)	37.5	56.0	40.0	61.4	48.7
Industry Average CF (%)					*45.1*
Equivalent Availability Factor (%)	74.8	87.6	87.1	86.1	83.9
Industry Average EAF (%)					*86.1*
Equivalent Forced Outage Rate (%)	9.6	4.0	6.0	3.9	5.9
Industry Average EFOR (%)					*7.9*

In general, the station average EAF and EFOR for the years 2004 to 2007 were comparable to industry averages. However, there were outage activities over the past 4 years that affected the EAF and EFOR of the unit. These events are listed below:

- TY3 was down in the spring of 2004 for a scheduled generator stator rewind. TY3 was off-line again in the fall of 2004 for a planned 2 week minor turbine overhaul due to high vibration. The TY3 steam turbine vibration is considered normal as of August 2008, and the next major steam turbine overhaul is scheduled in 2010.
- TY3 experienced a 1 week forced outage event in 2004 associated with the condensate filtering system, as well as a 3 day outage associated with the ESP. These outages resulted in a higher than normal forced outage rate given the low service hours for the unit due to planned outage activities in 2004.

Based on interviews with plant personnel and a review of the documentation provided, unless otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget.

2.7.4 Operations and Maintenance

A review of the organization chart for the Tyrone Generating Station identifies a traditional organization, although one that utilizes a minimal number of personnel. The organization chart did not specifically indicate an outage planning coordinator or any one individual dedicated to the outage planning function. However, with only one steam generating plant and a limited number of outages, a dedicated staff person may not be appropriate.

The operating report indicated that an intensive operator training effort was under way and continuing. This training includes CD ROM-based training from Primedia. The Primedia program is a general power plant training curriculum.

The Tyrone Generating Station, like all the other EON units, utilizes the Maximo CMMS application for maintenance planning. The operating plan indicates that the Tyrone Generating Station is now using Maximo to plan and schedule all maintenance activities at the plant. The plan also noted Tyrone Generating Station's efforts with respect to the boiler circuit maintenance strategy. All indications are that the staff at the Tyrone Generating Station has begun implementing the elements of this strategy to better manage the condition assessment and reliability of the boiler. The operating plan appropriately noted the concern that failure to implement specific boiler repair/replacement projects could compromise the plant's ability to meet EFOR targets.

Outage Management

The operating plan identifies a 3 week annual outage and 8 week major outages. The annual outages are generally focused on boiler, coal mill, and auxiliary equipment. The 8 week major overhaul allows for more extensive boiler projects, but is primarily driven by the need to perform turbine/generator maintenance.

O&M Historical Expenses

Table 2.7-4 illustrates the historical O&M expenses for the Tyrone facility.

Table 2.7-4
Tyrone Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M	$4,256	$3,823	$4,253	$4,160	$4,1010
Other Cost of Services		$87	$64	$57	$81
Fuel Handling	$257	$776	$326	$458	$1,017
Below the Line	$0	$0	$0	$0	$0
Total Controllable	$4,513	$4,686	$4,643	$4,675	$5,108
Net Generation (GWH)	261	399	376	326	255
Controllable/MWh	$17.28	$11.75	$12.34	$14.35	$20.03

2.7.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Four Black & Veatch engineers visited the facility on July 18, 2008. The facility appeared to be in good condition for a unit of this age. Units 1 and 2 have been decommissioned, with Unit 3 (TY3) the sole operating unit. The flue gas ductwork appeared to be in good condition, since the exit temperature from TY3 is maintained above dew point temperatures. The quality of housekeeping was typical of many operating coal fired power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil, water, or steam; corrosion damage; or other distress. The undisturbed state of other equipment and facilities from the retired and abandoned units do not appear to present risks to the remaining operating unit.

Boiler

The station does not have plans for any significant capital investment in boiler tubes for the 2009 to 2012 planning period. The station has reported very few tube leaks over the past 3 years, and plant personnel are not concerned with the reliability of the boiler. This is validated to some degree by the low number of forced outage incidents related to boiler tubes. A deposit-weight-density analysis was performed on a waterwall tube sample in 2006 that indicated no significant deposits and generally good conditions. Several tube failures in 2007 at the lower waterwall slope area were repaired, and replacement of short lengths of tubes was performed during the subsequent annual outage.

Pulverizer-related failures have been the main causes of forced outage events. The last pulverizer conversion project is planned for one pulverizer in 2008. This conversion will complete the upgrade of the pulverizers to the more current, manufacturer supported configuration. The recent upgrade of the original equipment to the EL series in the last several years was completed as part of the capital project for the Tyrone Station. The plan O&M budget for 2009 to 2012 of $160,000 per year is expected to be sufficient for this equipment in the mid term.

The outage strategy for this station calls for an annual 3 week outage for service of the boiler, coal mills, and auxiliary equipment. Future major tube replacement is not anticipated for the 2009-2012 planning period.

Steam Turbine

The TY3 steam turbine is overhauled every 7 years and is due for a major outage in 2010. TY3 was last overhauled in 2003 during which time the major work completed included installation of new steam seals on the HP turbine, a generator rewind, LP blade repairs, and thrust bearing refurbishment. The HP and LP turbines underwent boresonic inspections and were determined to have a probability of failure of less than 0.01 percent, assuming 25 starts per year for the next 20 years. Visual inspection of the nozzle block indicated erosion, but this was not removed or repaired. Significant scale buildup was found on the HP and LP spindles and blades, which were cleaned; it was determined that the buildup consisted primarily of silicates likely associated with water treatment chemicals. Significant erosion was found in 2003 on the HP turbine first two rows of blades. Repairs were performed at that time, with blade replacement planned for 2010 to ensure reliable operation. Significant damage of the LP spindle was also found, such as wear on the balance wheel, cracks near the balance wheel tapped holes, a missing blade GE L-5, severe erosion of the inlet edge for L-3, L-2, L-1, L-0 strips, and erosion to the trailing edge of numerous blades. Grinding out of cracks, and weld repairs were performed.

In 2003, the generator stator coils were repaired due to bar girth cracking, end basket greasing, and end-winding epoxy creep. The rotor was removed, thoroughly cleaned, and rewound. Except for expected wear due to aging of the equipment, the plant reported no major, unexpected problems with the generator.

Balance-of-Plant

The TY3 condenser underwent eddy-current testing in 2007 that indicated 60 tubes had more than 80 percent wall loss; it was found that the majority of the tubes in the unit contained moderate to major defects. Approximately 12 percent of the tubes had 60 to 80 percent wall loss, and about 18 percent of the tubes had 40 to 60 percent wall loss. The TY3 capital project plan includes replacement of the condenser tubes in 2012 at a cost of $1,231,000.

The original generator step-up transformer failed in 2001, and a new transformer was purchased to replace it. No major problems have been reported with the new transformer.

A significant operating issue for the station is the handling of combustion wastes. Fly ash and bottom ash are both sluiced to the existing ash pond. The plant creates approximately 50,000 cubic yards of ash per year of operation. The existing pond has a remaining capacity of 80,000 cubic yards. The ash pond at the site is essentially full, and the plant excavates the ash, stacks it out to dewater, and then trucks it offsite. In recent years, the plant has been successful in locating beneficial reuse projects.

The options are to continue to locate beneficial reuse projects, to truck ash to a commercial landfill, or to truck the ash to the adjacent E.W. Brown station ash ponds. The cost to transport ash to E.W. Brown was noted to be approximately $10 per ton, whereas a recent beneficial reuse project expended $6 to $8 per ton. The site has sufficient land available to create a landfill, but plant staff noted that such a project would likely not be funded. Ash disposal will continue to be a long-term risk and expense for the station. At this time, EON is still evaluating the best long-range plan for ash disposal at the station to resolve this issue.

2.7.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.1.7. From the information provided, the existing Tyrone Generating Station appears to have the required environmental permits in place and appears to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON submitted a 2007 Annual Air Compliance Certification indicating that Tyrone is in compliance with air permit conditions, with the exception that Unit 3 had six opacity exceedances greater than its 40 percent threshold because of unit upset.

Other

- Disposal of fly ash and bottom ash will be an ongoing issue for this unit because of the limited disposal capacity onsite. If local beneficial reuse projects do not continue as in the past, costs of ash disposal will significantly increase.

2.7.7 Key Findings

- Tyrone Generating Station appears to have the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.
- With the vacature of the CAIR and CAMR, this facility is now at greater risk for new AQC upgrade/retrofits, depending on the specific regulations that may replace the CAIR and CAMR. If a new emission trading scheme is not enacted, the coasts for required AQC retrofits, to meet the Hg MACT alone, may pose a significant challenge to the continued operation of these units.
- Unit 3 burns a very low sulfur coal, which must be trucked approximately 100 to 150 miles, depending on which mine is being sourced. The fuel quality requirement is the reason the fuel cost for the unit is relatively

more expensive than other EON coal fired plants. Therefore, the unit has been mainly dispatched in load-following mode instead of baseload mode.

3.0 Combustion Turbine Plants

3.1 Trimble County Station Combustion Turbines

3.1.1 Introduction

Trimble County Generating Station (Trimble County) is located approximately 5 miles west of Bedford, Kentucky, along the Ohio River. The site location is illustrated on Figure 3.1-1. Trimble County is a combined coal fired generating and CT station that began operation of its CTs in May 2002. The station is situated on approximately 1,004 acres.

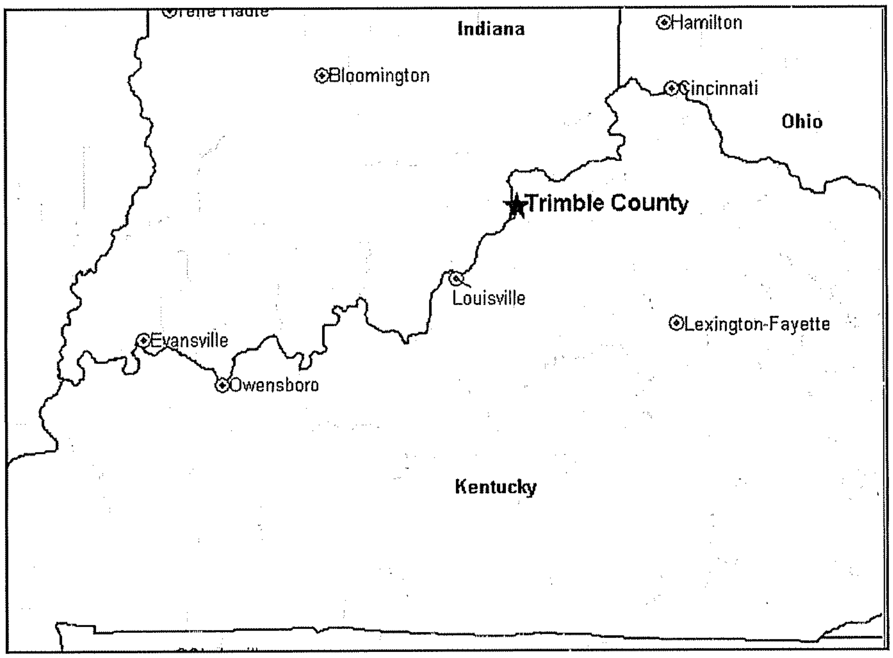

Figure 3.1-1
Trimble County Generating Station Location

The Trimble County natural gas fired simple cycle power plant has a net summer capacity of 960 MW. It is composed of six GE PG7241 FA natural gas turbines with water cooled generators and plant auxiliaries. Table 3.1-1 provides a summary of facts for Trimble County.

Trimble County's electrical interconnection is through a 345 kV substation located adjacent to the CTs to provide base and peak power to the electric grid. Power generated from the coal fired plant serves as a baseload source, while the CTs supply power for peak load demand.

Table 3.1-1
Trimble County Combustion Turbine Plant Fact Sheet

Category	Data	Category	Data
Location:	Bedford, KY	**Market Area:**	Midwest
Nominal Capacity:	960 MW net summer	**Off-Take:**	EON network customers
Ownership:	Units 5-6: LG&E - 29 % KU - 71 % Units 7-10: LG&E - 37 % KU - 63 %	**Electric Interconnection:**	Trimble County 345kV Substation
Fuel:	Natural Gas	**Fuel Supply:**	LG&E Energy Group via Texas Gas
Type:	CT simple cycle	**COD:**	May 14, 2002
Equipment:	6 x GE PG 7241(7FA+e) gas fired CTs with evaporative cooled inlet system	**Operator:**	LG&E

Notes:
1. Nominal Capacity represents 100 percent of summer net electrical output.

Natural gas is delivered to the station via an LG&E lateral connected to the Texas Gas transmission system. Natural gas is purchased based on open market rates obtained by the LG&E Trading Group and a firm transportation agreement between KU and Texas Gas.

3.1.2 Plant Description and Design

Siting and Real Estate

Trimble County is located in a rural area approximately 5 miles west of Bedford, Kentucky, at the intersection of State Highways 754 and 1838. The entire site covers 2,172 acres, of which 1,004 acres are dedicated to the active plant site. Trimble County is bordered by Corn Creek to the north, State Highway 754 to the south, State Highway 1838 (Corn Creek Road) on the east, and the Ohio River to the west. An aerial view of the site is shown on Figure 3.1-2.

The Trimble County CTs (CT5 through CT10) are located south of Trimble County Unit 1 and adjacent to the switchyard. Access to the CT site is through the coal plant's main entrance.

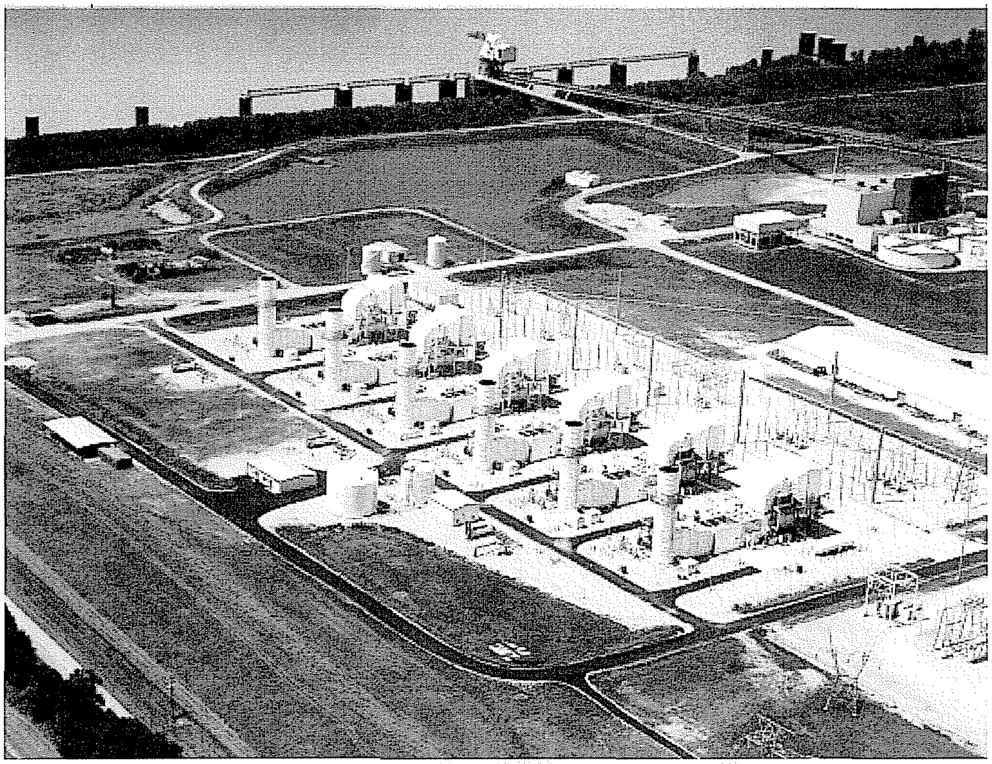

Figure 3.1-2
Trimble County Generating Station Combustion Turbines

Equipment

Table 3.1-2 provides a summary of the major equipment at the Trimble County CT plant. The plant configuration is considered typical of a simple cycle application and includes equipment suitable for power generation applications.

Combustion Turbines

Trimble County is equipped with six GE PG7241 FA+e natural gas fired turbines with water-cooled generators. The GE PG7241 FA CT is ISO-rated at 171 MW and 9,360 Btu/kWh. The turbine is a single-shaft, single-casing, advanced class machine with an 18 stage axial flow compressor, a 3-stage expansion turbine, 2 axial bearings, and 14 cannular-type, gas, dry low NO_x combustors. The compressor section of the gas turbine provides a 15:1 compression ratio, requiring a minimum fuel gas pressure of 380 psig. The baseload turbine inlet temperature is 2,385° F. Each turbine has a self-contained, closed loop cooling system with external air-fan heat exchanger.

Table 3.1-2
Trimble County Combustion Turbines Major Equipment

Description	Quantity	Characteristics
CTs	6	GE PG7241 (7FA+e) DLN2.6 CTs. Natural gas fired, capable of 160 MW net summer capacity
Generators	6	GE 7FH2, 18kV, 234MVA, static excitation
Transformers	6	210 MVA, 18 kV- 345 kV
Control Systems	6	GE Mark VI turbine control, Honeywell TDC-3000 for BOP
Inlet Cooling	6	Evaporative coolers
Natural Gas supply	1	6 mile long, 30 inch diameter, LG&E owned, with pressure reducing valve station

Fuel Supply

Natural gas for the CT units is purchased by the LG&E Energy Trading Group and transported to the station through a Texas Gas transmission pipeline. A dedicated 6 mile 30 inch branch line, which is owned and operated by LG&E, provides the interface between the Texas Gas distribution system and Trimble County.

On April 1, 2008, KU and Texas Gas signed a 5 year firm transportation agreement for the purchase of natural gas for two CTs for the summer months between April and October. The agreement, found in Appendix C, stipulates total entitlements, point of delivery, and contracted daily demand rate.

Electrical and Interconnection

Electricity produced in the generators is bussed to each unit's generator step-up transformer, where transformation to 345 kV occurs, followed by distribution to the existing LG&E 345 kV system.

Potable Water System

The potable water system supplies all domestic water as needed within the station. Water is supplied to the potable water system from Trimble County Water District No. 1. According to the SPCC Plan, three onsite groundwater supply wells were installed, but are not used.

3.1.3 Performance

Table 3.1-3 shows the historical net generation, CF, EAF, and EFOR for Trimble County CTs. The table also shows the industry averages for CF, EAF, and EFOR. Industry average data is developed using the GADS database provided by NERC and are for units in the SERC and RFC NERC regions for the years 2000 through 2006. The industry averages are as reported for units between 150 and 250 MW for all six units.

The historical operating heat rates for Trimble County have a weighted average of approximately 11,700 Btu/kWh for the period from 2004 to 2007. Trimble County Station personnel reported that the units are not always dispatched at full load.

Based on historical operating data for the six units at Trimble County shown in Table 3.1-3, the EFOR was at times above the industry average. During the early years of operation, the EFOR was relatively high due to GE 7FA fleetwide issues that have now been mostly resolved, as evidenced by lower EFOR values in 2005, 2006, and 2007, with the exception of TC10. It appears that future EFOR levels should be better than the industry average except for TC10. The following are explanations for unplanned outages that had a significant effect on the EFOR in recent years.

Trimble County Unit 5

- 2005: The EFOR was affected by a single forced outage event. The total time out of service was 39 hours due to starting system problems.

Trimble County Unit 6

- 2007: The EFOR was largely affected by two unplanned outages. The total time out of service was 347 hours due to exhaust problems and HP compressor bleed valves issues.

Trimble County Unit 7

- 2004: The EFOR was largely affected by three unplanned outage events. The total time out of service was 33 hours due to the issues with the process computer, generator controls, and switchyard circuit breakers.
- 2006: The EFOR was largely affected by two unplanned outages. The total time out of service was 254 hours due to combustor and compressor LP issues.

Table 3.1-3
Historical Performance Data for Trimble County Generating Combustion Turbines

	2004	2005	2006	2007	Average
Unit 5					
Net Generation (MWh)	21,655	9,696	11,781	92,511	33,911
Net Heat Rate (Btu/kWh)	10,607	10,307	11,590	11,577	11,332
Capacity Factor (%)	*1.6*	*0.7*	*0.8*	*6.6*	*2.4*
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	96.6	98.2	99.0	98.8	98.2
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	27.3	34.4	27.2	11.1	25.0
Industry Average EFOR (%)					*21.0*
Unit 6					
Net Generation (MWh)	22,823	22,419	23,800	83,953	38,249
Net Heat Rate (Btu/kWh)	11,654	11,604	11,545	11,356	11,466
Capacity Factor (%)	*1.6*	*1.6*	*1.7*	*6.0*	*2.7*
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	96.2	98.3	98.4	98.6	97.9
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	25.0	18.5	26.1	35.7	26.3
Industry Average EFOR (%)					*21.0*
Unit 7					
Net Generation (MWh)	13,524	44,210	50,944	112,701	55,345
Net Heat Rate (Btu/kWh)	22,123	11,706	11,437	11,491	12,171
Capacity Factor (%)	*1.0*	*3.2*	*3.6*	*8.0*	*3.9*
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	92.2	97.8	94.7	96.5	95.3
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	35.2	11.3	47.4	2.5	24.1
Industry Average EFOR (%)					*21.0*
Unit 8					
Net Generation (MWh)	5,784	77,153	76,814	149,775	77,382
Net Heat Rate (Btu/kWh)	31,349	11,619	11,332	11,365	11,794
Capacity Factor (%)	0.4	5.5	5.5	10.7	5.5
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	91.3	97.7	97.5	97.9	96.1
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	42.2	10.8	15.5	1.9	17.6
Industry Average EFOR (%)					*21.0*

Table 3.1-3 (Continued)
Historical Performance Data for Trimble County Generating Combustion Turbines

	2004	2005	2006	2007	Average
Unit 9					
Net Generation (MWh)	9,370	46,514	59,506	148,371	65,940
Net Heat Rate (Btu/kWh)	27,315	11,626	11,242	11,312	11,920
Capacity Factor (%)	*0.7*	*3.3*	*4.3*	*10.6*	*4.7*
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	90.0	98.8	96.4	97.4	95.7
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	29.7	6.8	14.5	3.1	13.5
Industry Average EFOR (%)					*21.0*
Unit 10					
Net Generation (MWh)	1,387	90,645	71,377	130,929	73,585
Net Heat Rate (Btu/kWh)	54,612	11,447	11,124	11,261	11,489
Capacity Factor (%)	*0.1*	*6.5*	*5.1*	*9.3*	*5.3*
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	83.9	96.3	93.8	95.3	92.3
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	94.8	22.8	45.4	0.9	41.0
Industry Average EFOR (%)					*21.0*

Trimble County Unit 8

- 2004: The EFOR was affected by a series of unplanned outages. The total time out of service was 31 hours due to lightning, switchyard circuit breakers, the gas fuel system, and the cooling water system.

Trimble County Unit 9

- 2004: The EFOR was affected by a series of unplanned outages, and was also affected by the relatively low dispatched operating hours. The total forced time out of service was 24 hours due to generator and switchyard circuit breakers, and the cooling water system.

Trimble County Unit 10

- 2004: The EFOR was largely affected by a series of unplanned outages. The total time out of service was 256 hours due to switchyard circuit breakers (213 hours), transformer cooling system, generator, and cooling water system.
- 2006: The EFOR was largely affected by an unplanned outage. The total time out of service was 414 hours due to compressor HP issues.

Based on interviews with plant personnel and review of the documentation provided, unless otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and all forced outage events have been resolved, except perhaps TC10.

3.1.4 Operations and Maintenance

Trimble County performs preventive maintenance in accordance with the central plant maintenance software (Maximo), including: PEECC battery, air compressor oil change, hydraulic oil accumulator, deionizer fuel gas strainer, hydrogen control panel, turning gear, CO_2 storage tank, CO_2 fire protection system, generator level indicators, cooling water skid, collector inspection, evaporator cooler pneumatics, compressor inlet guide vane (IGV)/bleed system, MCC inspection, accessory module monthly maintenance, and other activities appropriate for a CT site.

Trimble County also reports that it monitors, and plans to address, all of the GE Technical Information Letters (TIL) related to known maintenance, operational, or upgrade recommendations from the original equipment manufacturers.

Trimble County plans the following capital improvement projects in the planning period of 2009 to 2011, associated with the CTs:

- Continuous Dynamic Combustion Monitor System ($600,000) – Combustion tuning instrumentation will be permanently installed to allow remote monitoring and tuning by non-OEM vendors and in-house plant personnel following combustor outage maintenance or winter-summer ambient changes.
- CT Turbine Rotor First Stage Wheel Replacement ($2,311,250) – GE TIL 1334 applies only to TC5 and TC6 and requires replacement of the second stage turbine buckets during the first hot gas path inspection. Procurement of these parts is included in the planning period.
- CT Lube Oil Filter/Varnish Removal – GE7FA units are subject to development of varnish in the turbine lube oil systems (GE TIL-1528), which causes sticking in the control oil system for IGV and fuel gas servo valves. To address this issue, Trimble County personnel plan to install the proper filter system on each CT for the capital budget item of $104,000 in the planning period.

Several TIL issues already addressed through O&M include the following:

- GE TIL S17 blade distress: At inlet air temperatures below 40° F, units are subject to reduced load change ramp rates, and automatic generation control (AGC) is not available in entirety.
- GE TIL-1502 compressor rubs in aft end: units are not re-started between 2 and 8 hours following a shutdown in accordance with TIL.
- GE TIL 1562 compressor shims: units are bore-scoped and all loose shims are removed to avoid liberation and subsequent blade damage.
- GE TIL 1509, compressor blades R0: TC9 and TC10 were subject to design deficiency in R0 blades that resulted in blade liberations; these defective blade rows have been replaced.
-

Outage Management

All of the CTs at Trimble County were manufactured by GE, with schedules for major maintenance in accordance with the GE specification GE-3620 Heavy-Duty Gas Turbine Operating and Maintenance Considerations. The manufacturer's calculation for factored hours (FH) and factored starts (FS) adjusts the actual operating hours to account for known maintenance factors, including the number of starts, number of trips, hours of peak operation, temperature of startup, and other considerations. Trimble County reported that it performed the maintenance for all of its CT units in accordance with the manufacturer's recommendations that are a common interval for all six PG7241FA7FA units:

- Combustion inspection due at the earlier of either 12,000 FH or 450 FS.
- Hot gas path inspection due at the earlier of either 24,000 FH or 900 FS.
- Major inspection due at the earlier of either 48,000 FH or 2,400 FS.

The combustion inspection is a relatively short disassembly inspection of fuel nozzles, liners, transition pieces, and flame path. The inspection concentrates on combustion liners, transition piece fuel nozzles, and end caps, which are recognized as being the first to require replacement and repair in a good maintenance program.

The hot gas path inspection includes the full scope of the combustion inspection, plus a detailed inspection of turbine nozzles, stator shrouds, and turbine buckets. To perform this inspection, the top half of the turbine shell must be removed.

The major inspection involves examination of all internal rotating and station components from the inlet of the machine through the exhaust section of the machine.

Trimble County load profile, and the nature of peaking duty, results in starts-based maintenance because FS intervals are reached before FH intervals. Table 3.1-4 identifies the CT statistics and planned outages as of June 2008.

Table 3.1-4
Planned Outage for Trimble County Combustion Turbines

	FS	FH	FH/FS	Planned Outage for Combustion Inspection	Planned Outage for Hot Path Inspection
CT Unit 5	631	2,848	4.5	2007 – Done	2013
CT Unit 6	596	2,787	4.7	2008 – Done	2013
CT Unit 7	506	2,383	4.7	2008 – Done	2014
CT Unit 8	533	3,313	6.2	2009	2014
CT Unit 9	496	2,787	5.6	2009	2014
CT Unit 10	422	2,845	6.7	2010	None

Trimble County's planned outages for 2009 to 2012 appear to be misaligned with the projected FS required to meet corresponding net generation (MWh). Several maintenance activities are expected to be due earlier than planned according to the range of FH/FS accumulated at Trimble County's CTs.

O&M Historical Expenses

The O&M historical costs for Trimble County CTs are included in the overall costs of the Trimble County Station.

Trimble County's plan to minimize capital expenditures associated with combustor inspections is to perform these outages in alignment with generation planning so that extended down time can be minimized. This advantage of time allows combustion inspection parts to be refurbished during the overhaul, rather than purchasing significant spare parts prior to the outage. This option lowers the capital costs caused by the redundancy of spares, as a trade-off for allowing a 12 week outage schedule in lieu of the typical 2 weeks for this maintenance activity. The Trimble County budget of $964,000 per combustion inspection is included in O&M category. The long-term plan budget for the hot gas path inspection is estimated by Trimble County Station as $8,000,000 per turbine, based on discussions with GE, a decision to not enter into GE's Long Term Service Agreement (LTSA), discussions with alternate parts suppliers, and anticipation of aftermarket parts availability.

3.1.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Five Black & Veatch engineers visited the facility on July 10, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating CT power plants. The equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil, water or steam, corrosion damage, or other distress. Electrical equipment appeared to have been well maintained.

Combustion Turbines

Trimble County's CTs are relatively new. Units 5 and 6 simple cycle CTs, consisting of GE series 7FA+E were constructed and placed in service in 2002, producing nameplate 152 MW each. Two years later, Units 7-10 were commissioned, also GE series 7FA+E, in simple cycle and producing 152 MW each.

A review of the outage schedule for both CTs shows that turbines have undergone frequent inspections and modifications per GE recommendations. Even in the absence of an LTSA, GE has been sought for advice and services in maintaining the units.

Balance-of-Plant and Electrical

The six CTs are subject to several GE TILs. Plant staff indicated that all of the TILs are being addressed in accordance with manufacturer recommendations.

Trimble County's personnel have identified a need for improved redundancy of air supply to the CTs, since all six units are supplied with air from a set of air compressors powered from a common MCC that does not have backup feed. Loss of the

MCC will result in a multiple-unit outage. Trimble County personnel have proposed a capital improvement project of $30,000 to install an air line from the fossil units (TC1/TC2) area for enhanced redundancy of air supply.

Low CEMS reliability is reported for both the NO_x and CO systems due to the short run times inherent in the role of these units to provide intermittent peaking power. The short run times can prevent the CEMS from being calibrated during operating periods on a given day in compliance with 40 CFR Part 60 reporting and can proportionally increase the hours that are considered invalid due to insufficient data being collected to comply with full hour reporting. The additional evaluation into the background of the CEMS reporting and the high reliability reported under the Part 75 program indicates that the initial concerns with the low reliability reported for the CEMS under the applicable Part 60 program is fully explained and justified for these particular units.

3.1.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.2.1. From the information provided, the existing Trimble County Generating Station (CT units) appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review are listed below:

Air

- EON has submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with permit conditions, with the exception of the following minor items:
  - The current air construction and operating permit (Permit V-02-043, Revision 3) notes that the CO emission limit for the Trimble County CTs is 9 ppm (by volume at 15 percent oxygen, on a dry basis), but the 2007 Annual Air Compliance Certification indicates that the Trimble County CTs CO emission limit is 9.5 ppm. Based on the 9.5 ppm CO emission limit noted in the report, no excess emissions were reported for these units. However, no additional CO emissions information on individual Trimble County CTs was

available for review to determine if these units were exceeding their 9 ppm CO emissions limit.

- The current air construction and operating permit (Permit V-02-043, Revision 3) notes that the NO_x annual emission limit for the Trimble County CTs is 9 ppm (by volume at 15 percent oxygen, on a dry basis) and 12 ppm on an hourly basis. The 2007 Annual Air Compliance Certification indicates that several of the Trimble County CTs exceeded their emission limit during the months of April, May, and June 2007.
- 2007 Annual Air Compliance Certification indicates that the CT NO_x CEMS for all six units were unavailable for greater than 20 percent of their operating time.

3.1.7 Key Findings

- The Trimble County 2008 to 2012 budget forecast indicates that expenses for hot gas path inspections are not planned to occur until after 2012. This does not agree with operating profile projections that indicate the hot gas inspections for TC5, TC6, TC7, TC8, and TC9 will be due prior to 2012. An adjustment to the budget forecast of approximately $8 million per unit to cover the hot gas path maintenance events is recommended. This adjustment is made in the projected capital costs for these units contained herein.
- The operating profile projections for net plant heat rate for all of the CTs appears to be aggressive and is lower than the turbines have achieved in recent years.

3.2 E.W. Brown Station Combustion Turbines

3.2.1 Introduction

E.W. Brown Generating Station (E.W. Brown) is located approximately 5 miles northeast of Burgin, Kentucky, on the shores of Herrington Lake. The site location is illustrated on Figure 3.2-1. E.W. Brown is a combined coal fired generating and CT station that began operation of its CTs in 1994.

E.W. Brown is a natural gas and fuel oil fired simple cycle power plant with a net summer capacity of 849 MW. It comprises one Alstom GT11N2+ gas fired turbine, two Alstom GT24 gas/oil fired turbines, and four Alstom GT11N2 gas/oil fired turbines, all with water cooled generators and plant auxiliaries. Table 3.2-1 provides a summary of E.W. Brown station facts.

E.W. Brown's electrical interconnection is through the Brown CT substation and provides base and peak power to the electric grid. Power generated from the coal fired plant serves as a base; the CTs serve for peak load demand.

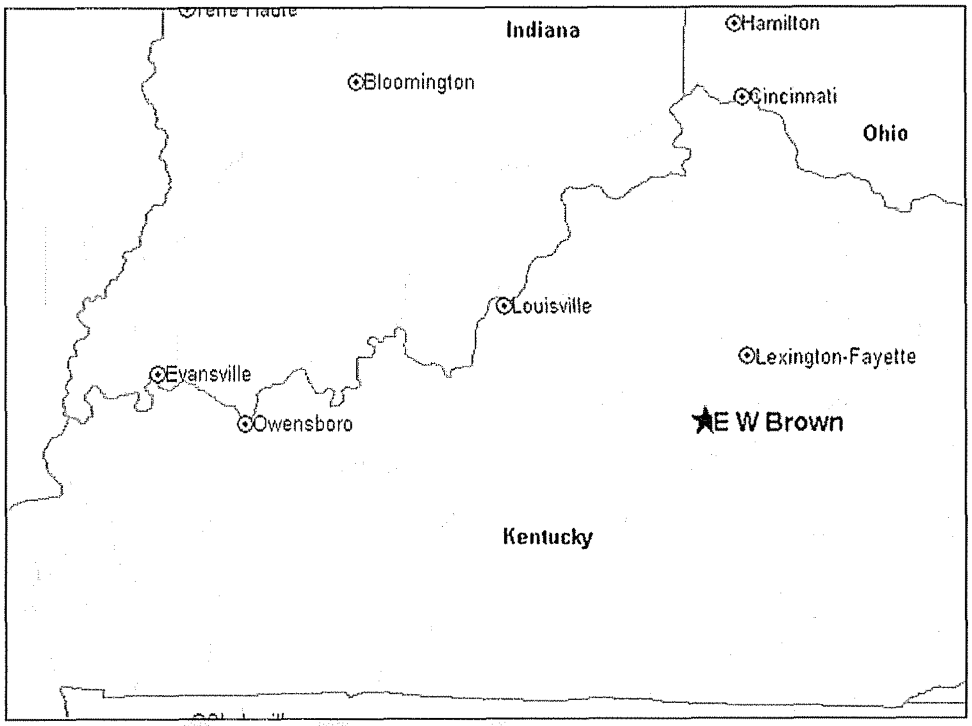

Figure 3.2-1
E.W. Brown Generating Station Location

Table 3.2-1
E.W. Brown Plant Fact Sheet

Category	Data	Category	Data
Location:	Burgin, KY	**Market Area:**	Midwest
Nominal Capacity:	849 MW net summer 947 MW with Chilled Water Inlet Air Cooling (2 hours capable per day)	**Off-Take:**	EON network customers
Ownership:	BRCT5: LG&E - 53 % KU - 47 % BRCT6-7: LG&E – 38 % KU – 62 % BRCT8-11: KU – 100 %	**Electric Interconnection:**	Brown CT Substation
Fuel:	Natural gas or distillate fuel oil	**Fuel Supply:**	NG: Kentucky Utilities via Texas Eastern or Tenneco Gas, FO: Purchased
Type:	Simple cycle	**COD:**	June 8, 2001
Equipment:	1 x Alstom GT11N2+ gas fired CT 2 x Alstom GT24 dual fuel fired CTs 4 x Alstom GT11N2 dual fuel CTs Chilled water inlet cooling system	**Operator:**	KU

Notes:
1. Nominal Capacity represents 100 percent of summer net electrical output.

Natural gas is obtained via a KU lateral that receives natural gas from either the Texas Eastern or Tenneco Gas Company transmission systems. Natural gas is purchased based on open market rates.

3.2.2 Plant Description and Design

Siting and Real Estate

E.W. Brown is located in Mercer County, approximately 5 miles northeast of Burgin, Kentucky, just off Highway 33. E.W. Brown is situated on the shore of Herrington Lake near the Dix Dam. An aerial view of the site is shown on Figure 3.2-2.

The E.W. Brown CTs, CT5 through CT11, are located west of E.W. Brown's coal fired generating units. Access to the CT site is through the station's main entrance on Dix Dam Road.

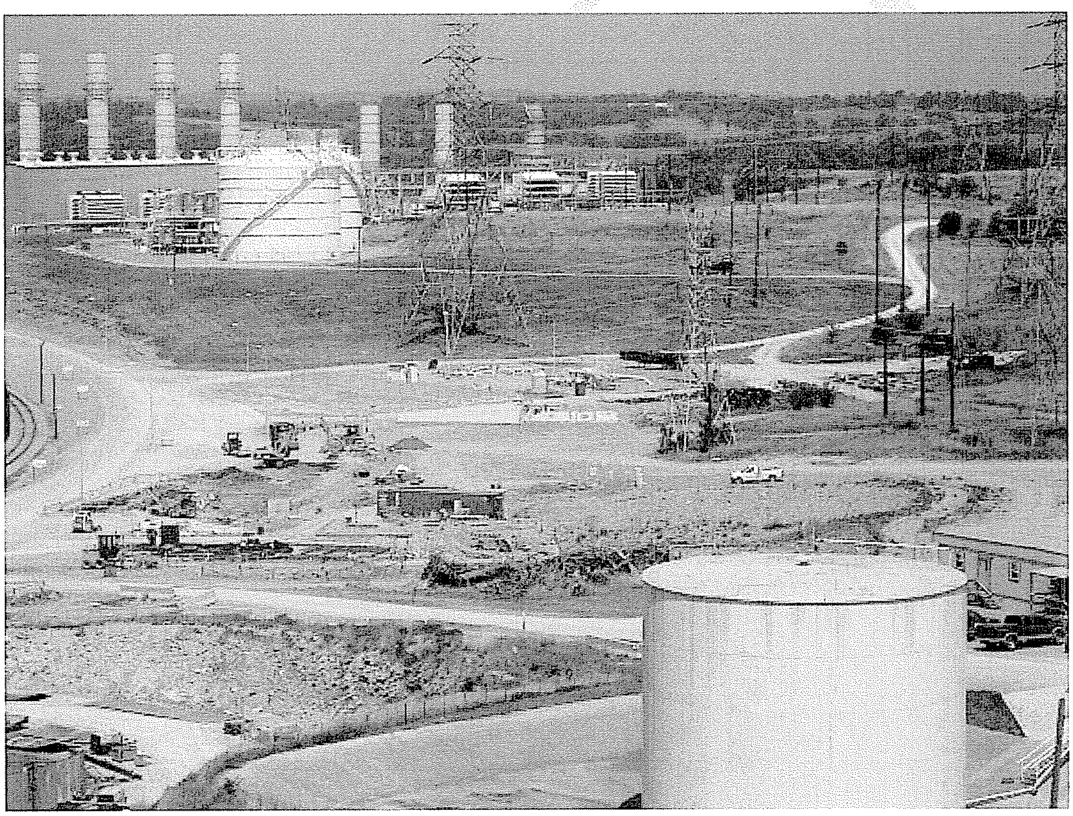

Figure 3.2-2
E.W. Brown Generating Station

Equipment

Table 3.2-2 provides a summary of the major equipment at the E.W. Brown plant. The plant configuration is considered typical of a simple-cycle application and includes equipment suitable for power generation applications.

Table 3.2-2
E.W. Brown Combustion Turbines Major Equipment

Description	Quantity	Characteristics
CTs	1	Alstom GT11N2+ silo-combustor style CT with water injection for NO_x control. Natural gas fired, rated for 117 MW net summer capacity.
	2	Alstom GT24 axial-combustor style CT with dry low NO_x burners on gas, and water injection for NO_x control on oil. Dual fuel (oil/natural-gas) fired, rated for 154 MW net summer capacity.
	4	Alstom GT11N2 silo-combustor style CT with water injection for NO_x control. Dual fuel (oil/natural-gas) fired, rated for 106 MW net summer capacity.
Generators	7	(1) 123 MW, (2) 177 MW, (4) 126 MW Alstom, water-cooled
Transformers	7	(1) 135MVA, (2) 190MVA, (4) 125MVA
Control Systems	7	Alstom/Foxboro I/A
Inlet Cooling	1	Inlet Air Chilling System – inlet chilling coils, chilled water piping, and thermal storage tank for ice/chilled water, with chiller plant. Capable of 98 MW net additional summer capacity for 2 hours on five GT11N2.
Water Treatment System	1	Reverse osmosis water plant
Demineralized Water Storage	1	Common storage tank, capacity shared with coal units
Fuel Oil	1	2.5 million gallon storage tank
Natural Gas supply	1	13 mile long, KU-owned, with gas compressor to assist in line pack capacity, and pressure reducing valve station

Combustion Turbines

E.W. Brown is equipped with seven Alstom natural gas/oil fired turbines producing a net summer total of 849 MW. The composition consists of one Alstom GT11N2+ gas fired turbine with an ISO-rated 112 MW at 12,831 Btu/kWh, two Alstom GT24 gas/oil fired turbines with an ISO-rated 157.5 MW at 10,680 Btu/kWh, and four Alstom GT11N2 gas/oil fired turbines with an ISO-rated 102.5 MW at 12,251 Btu/kWh, all with water-cooled generators and plant auxiliaries. The following are key characteristics of all the Alstom CTs:

- Self-contained, closed loop cooling system, with external air-fan heat exchangers.
- Inlet air filtration.
- Inlet air chilling coils.
- Sound attenuating turbine enclosure.
- CO_2 fire protection system.
- Demineralized water injection for NO_x control.

Auxiliary Equipment

Equipment that is common at the E.W. Brown CT site includes the following:

- Natural gas supply line, 13 miles long, with gas compressor and pressure reducing valve station.
- Fuel oil storage tank, rated for 2.5 million gallons.
- Station air compressors.
- Reverse osmosis water plant for demineralized water.
- Demineralized water storage tank.
- Ice/cold water thermal storage system, ammonia based, capable of lowering air inlet temperatures to obtain a rated 20 MW per CT for several hours.

Fuel Supply

The natural gas pipeline supplying the CT units sited at E.W. Brown runs across the top of the Dix Dam. This natural gas pipeline is part of the 13 miles of pipeline owned by KU. The natural gas is supplied by either Texas Eastern or Tenneco Gas Companies.

E.W. Brown typically receives fuel oil shipments by tanker trucks, but also has facilities to receive fuel oil by railcar. The CT plant fuel oil unloading stations are built with a depressed roadway that drains to an oil/water separator prior to being pumped to the station ash pond. These unloading stations are designed to unload railcars as well, should this be required in the future.

Water and Wastewater

All water serving both the coal and the CT plant are withdrawn from two intake structures located in Herrington Lake. Herrington Lake is the impoundment that was formed behind Dix Dam when it was completed in the 1920s. This lake also serves as the water supply for the city of Danville. Sanitary wastes at the CT plant are tanked and privately contracted to a treatment facility. Subsection 4.2.5 of this report provides further information about the Dix Dam.

The E.W. Brown CT plant has three oil/water separators that discharge to the ash treatment basin prior to discharge to Herrington Lake.

3.2.3 Performance

Table 3.2-3 shows the historical net generation, CF, EAF, and EFOR for E.W. Brown CTs. The table also shows the industry averages for CF, EAF, and EFOR. Industry average data is developed using the GADS database provided by NERC and are for units in the SERC and RFC NERC regions for the years 2000 through 2006. The industry averages are as reported for units between 100 and 150 MW for Unit 5 and Units 8 to 11 and between 150 and 200 MW for Units 6 and Unit 7.

The historical operating heat rates at E.W. Brown CTs have a weighted average of around 16,000 Btu/kWh for the Alstom GT11N2 and 11,600 Btu/kWh for the GT24 for the period from 2004 through 2007. The E.W. Brown station personnel reported that the units are not always dispatched at full load. The relatively high heat rates are also a result of the short run times compared to startup and shutdown time.

Based on historical operating data for the seven units at E.W. Brown shown in Table 3.2-3, the EFOR was often above industry averages. The relatively high EFOR for the Brown CTs is mostly due to GT24 and GT11N2 fleet issues. It appears that the EFOR in the future will be similar to the recent past. The following are explanations for unplanned outages that had a significant effect on the EFOR:

- E.W. Brown Unit 5:
  - 2004: The EFOR was largely affected by one unplanned outage. The total time out of service was 70 hours due to a problem with the fire system.

Table 3.2-3
Historical Performance Data for E.W. Brown Station Combustion Turbines

	2004	2005	2006	2007	Average
Unit 5					
Net Generation (MWh)	0	122,928	30,777	19,823	43,382
Net Heat Rate (Btu/kWh)	0	12,584	13,483	15,986	13,132
Capacity Factor (%)	0.0	12.0	3.0	1.9	4.2
Industry Average CF (%)					*2.3*
Equivalent Availability Factor (%)	99.0	99.3	91.4	95.7	96.4
Industry Average EAF (%)					*91.9*
Equivalent Forced Outage Rate (%)	87.3	5.1	53.3	43.4	47.3
Industry Average EFOR (%)					*43.7*
Unit 6					
Net Generation (MWh)	10,697	172,114	97,500	88,563	92,219
Net Heat Rate (Btu/kWh)	15,016	11,150	11,459	11,797	11,703
Capacity Factor (%)	0.8	12.8	7.2	6.6	6.8
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	79.7	68.3	90.1	79.4	79.4
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	65.2	59.1	14.3	21.2	40.0
Industry Average EFOR (%)					*21.0*
Unit 7					
Net Generation (MWh)	20,845	156,711	99,267	51,599	82,106
Net Heat Rate (Btu/kWh)	12,608	11,512	11,298	12,012	11,595
Capacity Factor (%)	1.6	11.6	7.4	3.8	6.1
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	94.7	62.6	95.3	0.8	63.4
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	61.8	50.6	12.5	62.4	46.8
Industry Average EFOR (%)					*21.0*

Table 3.2-3 (Continued)
Historical Performance Data for E.W. Brown Station Combustion Turbines

	2004	2005	2006	2007	Average
Unit 8					
Net Generation (MWh)	0	2,954	46,424	19,870	17,312
Net Heat Rate (Btu/kWh)	0	19,415	14,482	15,192	14,896
Capacity Factor (%)	0.0	0.3	5.0	2.1	1.9
Industry Average CF (%)					*2.3*
Equivalent Availability Factor (%)	83.1	34.9	88.4	62.1	67.1
Industry Average EAF (%)					*91.9*
Equivalent Forced Outage Rate (%)	34.5	98.8	58.4	1.1	48.2
Industry Average EFOR (%)					*43.7*
Unit 9					
Net Generation (MWh)	0	1,636	27,103	11,236	9,994
Net Heat Rate (Btu/kWh)	0	24,093	15,426	15,915	15,918
Capacity Factor (%)	0.0	0.2	2.9	1.2	1.1
Industry Average CF (%)					*2.3*
Equivalent Availability Factor (%)	99.9	35.7	82.2	55.7	68.4
Industry Average EAF (%)					*91.9*
Equivalent Forced Outage Rate (%)	13.6	99.2	36.7	1.9	37.9
Industry Average EFOR (%)					*43.7*
Unit 10					
Net Generation (MWh)	772	1,683	20,966	5,334	7,189
Net Heat Rate (Btu/kWh)	34,934	25,069	15,653	21,983	17,896
Capacity Factor (%)	0.1	0.2	2.3	0.6	0.8
Industry Average CF (%)					*2.3*
Equivalent Availability Factor (%)	99.0	35.7	74.8	55.7	66.3
Industry Average EAF (%)					*91.9*
Equivalent Forced Outage Rate (%)	22.7	99.3	86.9	31.4	60.1
Industry Average EFOR (%)					*43.7*

Table 3.2-3 (Continued)
Historical Performance Data for E.W. Brown Station Combustion Turbines

	2004	2005	2006	2007	Average
Unit 11					
Net Generation (MWh)	467	1,854	12,930	4,458	4,927
Net Heat Rate (Btu/kWh)	86,814	19,620	15,936	16,286	18,041
Capacity Factor (%)	0.1	0.2	1.4	0.5	0.5
Industry Average CF (%)					*2.3*
Equivalent Availability Factor (%)	99.1	35.7	64.3	50.5	62.4
Industry Average EAF (%)					*91.9*
Equivalent Forced Outage Rate (%)	28.7	99.2	93.1	3.3	56.1
Industry Average EFOR (%)					*43.7*

- E.W. Brown Unit 6:
  - 2004: The EFOR was largely affected by a series of unplanned outages. The total time out of service was 224 hours due to problems with controls. The EAF was impacted by a planned outage of 1,502 hours to perform a major overhaul.
  - 2005: The EFOR was largely affected by an unplanned outage. The total time out of service was 1,217 hours due to turbine blade vibration. The EAF was affected by the continuation of the 2004 major overhaul, which lasted for another 838 hours.
  - 2007: The EAF was impacted by a major overhaul starting in November and continuing into December. This included 1,747 hours of planned maintenance.
- E.W. Brown Unit 7:
  - 2004: The EFOR was largely affected by an unplanned outage. The total time out of service was 287 hours due to a problem with the controls.
  - 2005: The EFOR was largely affected by a series of unplanned outages. The total time out of service was 1,170 hours due to fuel system and control system issues. The EAF was impacted by a planned major overhaul in April of 2,071 hours.
  - 2007: The EFOR was affected by a series of unplanned outages. The total time out of service was 653 hours due to generator rotor collector rings and turbine combustor problems.
- E.W. Brown Unit 8:
  - 2004: The EAF was impacted by a single planned outage event of 1,475 hours to rewind the generator stator.
  - 2005: The EFOR and EAF was largely affected by one unplanned outage. The total time out of service was 5,630 hours due to HP blade service.
  - 2006: The EFOR and EAF were largely affected by the continuation of the 2005 forced outage to address gas turbine HP blades. The outage continued into February and added 735 hours of forced outage time.
- E.W. Brown Unit 9:
  - 2005: The EFOR and EAF were largely affected by one unplanned outage. The total time out of service was 5,630 hours due to HP blade service.

  - 2006: The EFOR and EAF were largely affected by the continuation of the 2005 forced outage to address gas turbine HP blades. The outage continued into January and added 110 hours of forced outage time. In March the unit was forced down for 1,296 hours due to generator bearings.
- E.W. Brown Unit 10:
  - 2005: The EFOR and EAF were largely affected by one unplanned outage. The total time out of service was 5,630 hours due to HP blade service.
  - 2006: The EFOR and EAF were largely affected by the continuation of the 2005 forced outage to address gas turbine HP blades. The outage continued into March and added 1,685 hours of forced outage time.
- E.W. Brown Unit 11:
  - 2005: The EFOR and EAR were largely affected by one unplanned outage. The total time out of service was 5,630 hours due to HP blade service.
  - 2006: The EFOR and EAF were largely affected by the continuation of the 2005 forced outage to address gas turbine HP blades. The outage continued into January and added 1,685 hours of forced outage time.

Based on interviews with plant personnel and review of the documentation provided, unless otherwise noted above, it is Black & Veatch's understanding that all issues discovered during the above planned outage activities and forced outage events have been resolved, or there are plans to address the issues in the capital budget. It does appear that the E.W. Brown CTs may continue to have somewhat higher EFOR than the average, as indicated by the NERC/GADS benchmark indicators in Table 3.2.3.

3.2.4 Operations and Maintenance

Outage Management

All of the CTs at E.W. Brown were manufactured by Alstom, with schedules for major maintenance in accordance with the EOH method. The manufacturer's calculation for EOH adjusts the actual operating hours to account for known maintenance factors, including the number of starts, number of trips, hours of operation on oil, and other considerations. E.W. Brown performs the maintenance for all of its CT units in accordance with the manufacturer's recommendations that are a common interval for all seven units:

- A-Inspection due at 12,000 EOH.
- C-Inspection due at 24,000 EOH.

The A-Inspection generally consists of: filter-house/air inlet inspection, bore-scope of compressor blades and clearance checks, burner and combustor inspection, turbine bore-scope inspection, and clearance checks. The C-Inspection is extensive and includes major overhaul and wear (noble) parts replacement, including turbine blades. Table 3.2-4 identifies the CT statistics and planned outages as of June 2008.

Table 3.2-4
Planned Outage for E.W. Brown Station Combustion Turbines

	Equivalent Operating Hours	Planned Outage for C - Inspection
CT Unit 5	14,551	2015
CT Unit 6	30,826	2015
CT Unit 7	27,000	2016
CT Unit 8	25,000	2020
CT Unit 9	21,000	2011
CT Unit 10	21,000	2012
CT Unit 11	14,400	2016

O&M Historical Expenses

The historical O&M costs for the E.W. Brown CT units are outlined in Table 3.2-5.

Table 3.2-5
E. W. Brown Station Combustion Turbines O&M Expenses
($000)

	2003	2004	2005	2006	2007
O&M		$3,452	$4,044	$4,496	$4,738
Other Cost of Services					
Fuel Handling					
Below the Line	$29	$1	$0	$0	$0
Total Controllable		$3,453	$4,044	$4,496	$4,738
Net Generation (GWH)	42	82	460	254	201
Controllable/MWh		$42.11	$8.79	$17.70	$23.57

The budget for a C-Inspection on the 11N2 units (CT5, CT8, CT9, CT10, and CT11) is $11,500,000 based upon E.W. Brown's past experience, current parts pricing, and recent review meetings with Alstom. The budget for a C-Inspection on the GT24 units (CT6, CT7) is $31,500,000, derived from parts quotations from Alstom for the major parts.

3.2.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Three Black & Veatch engineers visited the station on July 18, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating CT power plants. The equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil or water, corrosion damage, or other distress. Electrical equipment appeared to have been properly maintained.

Combustion Turbines

A review of the outage schedule for the CTs shows that the turbines have undergone frequent inspections and modifications per Alstom recommendations. Even in the absence of an LTSA for the 11N2 machines, Alstom has been sought for advice and services in maintaining the units. The CTs have experienced fleet issues common to the GT11 and GT24 CTs. Black & Veatch believes that, for the most part, the fleet issues have been addressed or will be addressed during planned future maintenance periods.

Combustion Turbine Unit 5

Unit 5, the Alstom GT11N2+, had an inspection in 2006 at 13,060 EOH and no significant issues were reported following this combustor inspection. The unit's most recent performance test results indicated a net summer capacity of 103.5 MW at 12,645 Btu/kWh. This represents degradation from the initial acceptance test output of 116 MW at 12,186 Btu/kWh.

Combustion Turbine Unit 6

Unit 6, the Alstom GT24, was recently upgraded with A/B conversion in 2007-2008 as part of the LTSA with Alstom. The unit's most recent performance test results indicated a net summer capacity of 148.8 MW at 10,769 Btu/kWh. This represents degradation from the initial acceptance test (pre A/B conversion) output of 155 MW at 10,612 Btu/kWh.

Combustion Turbine Unit 7

Unit 7, the Alstom GT24, was recently upgraded with A/B conversion in 2007-2008 as part of the LTSA with Alstom. The unit's most recent performance test results indicated a net summer capacity of 144 MW at 10,389 Btu/kWh. This represents degradation from the initial acceptance test (pre A/B conversion) output of 155 MW at 10,575 Btu/kWh.

Combustion Turbine Unit 8

Unit 8, the Alstom GT11N2, had an inspection in 2005 at 21,000 EOH. Significant issues reported following this inspection were the 4th row vane cracking found. This cracking was addressed by replacement of the defective parts. Recent inspections by E.W. Brown has also revealed third-stage vane cracks on BRCT8; these parts are planned for replacement in 2011. The unit's most recent performance test results indicated a net summer capacity of 96.5 MW at 12,687 Btu/kWh. This represents degradation from the initial acceptance test output of 106 MW at 12,169 Btu/kWh.

Combustion Turbine Unit 9

Unit 9, the Alstom GT11N2, had an inspection in 2005 and had 4th row vane cracking which has already been addressed by replacement of the defective parts. The unit's most recent performance test results indicated a net summer capacity of 97.4 MW at 12,679 Btu/kWh. This represents degradation from the initial acceptance test output of 104.9 MW at 12,258 Btu/kWh.

Combustion Turbine Unit 10

Unit 10, the Alstom GT11N2, had an inspection in 2005 and had 4th row vane cracking which has already been addressed by replacement of the defective parts. The unit's most recent performance test results indicated a net summer capacity of 92 MW at 13,167 Btu/kWh. This represents degradation from the initial acceptance test output of 106 MW at 12,170 Btu/kWh.

Combustion Turbine Unit 11

Unit 11, the Alstom GT11N2, had an inspection in 2005 and had 4th row vane cracking which has already been addressed by replacement of the defective parts. The most recent performance test results indicated a net summer capacity of 95 MW at 12,956 Btu/kWh. This represents degradation from the initial acceptance test output of 104.7 MW at 12,418 Btu/kWh.

Balance-of-Plant and Electrical

E.W. Brown operates and maintains a 2,500,000 gallon oil tank to supply fuel oil to the CTs, with below grade and above grade distribution piping to each CT. The E.W. Brown Station experienced a fuel oil spill in 1999, reportedly due to below grade fuel oil piping rupture during construction activities. Specific actions being taken include the following:

- Installation of two oil/water separators for cooling tower blowdown streams (completed in 2006).
- Installation of new SPCC system; double-walled pipe or concrete trenching of below grade fuel oil distribution piping at the CT site (budget of $1,261,000 in 2009).

The condition of the tank itself was not reported to be of concern by E.W. Brown; specific inspection results were not reviewed by Black & Veatch.

3.2.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.2.2. From the information provided, the existing E.W. Brown Station appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant findings of the environmental review for the CTs are listed below:

Air

- EON has submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with permit conditions, with the exception of the following items:
  - CT-7 experienced 38 exceedances of the 3 hour rolling NO_X average. The report indicated that all of the exceedances occurred during fuel oil commissioning and testing and that Alstom used CEMS during the events and ensures that actual emissions did not exceed the 42 ppm NO_X limit.
  - CT-7 experienced two heat input exceedances with no reason acknowledged.

3.2.7 Key Findings

- The E.W. Brown CT8 unit, an Alstom GTN11N2 CT, was recently inspected and compressor third stage vane cracks were identified. A repair was made in 2006. E.W. Brown CT9, CT10, and CT11 use the same technology and could experience similar wear. It is recommended that an adjustment be made to the capital expenditures budget to add contingency for this possibility.
- The operating profile projections for net plant heat rate for all of the CTs appears to be aggressive and is lower than the turbines have achieved in recent years.
- In 1999, the facility experienced a fuel oil spill caused by a below grade fuel oil piping rupture during construction. It appears that the plant has taken prudent steps to mitigate a similar event occurring in the future.
- 2007 emissions reports for E.W. Brown CT7 indicate a number of high NO_x emission periods that were reported. The reason for the emissions is unknown and needs to be rectified to ensure future compliance.

3.3 Paddy's Run Station Combustion Turbines

3.3.1 Introduction

Paddy's Run Station is located close to Louisville, Kentucky, as illustrated on Figure 3.3-1. The facility consists of three gas fired CTs and has a combined declared summer capacity of 193 MW. These units are used for peaking power supply and dispatch occasionally for portions of a day during periods of high system demand in summer or other peak periods. These units are managed by staff from the Cane Run plant. PR13 can be remotely started from Cane Run.

The facility is composed of a Siemens V84.3A gas turbine rated at 152 MW installed in 2001, a GE 5001LA gas turbine rated at 16 MW installed in 1968, and a Westinghouse W-301-G gas turbine rated at 27 MW, also installed in 1968.

The Paddy's Run CT site is operated and maintained by a group of Cane Run Station personnel. Table 3.3-1 provides a summary of facts for the Paddy's Run CT station.

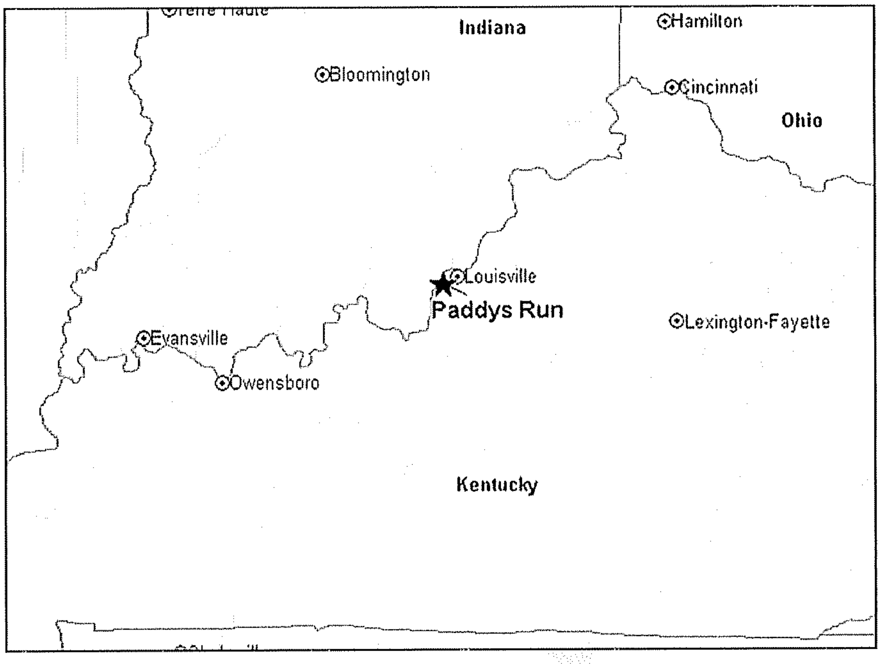

Figure 3.3-1
Paddy's Run Plant Location

Table 3.3-1
Paddy's Run Station Combustion Turbines Fact Sheet

Category	Data	Category	Data
Location:	Jefferson County, KY	**Market Area:**	Midwest
Nominal Capacity:	193 MW net summer	**Off-Take:**	EON network customers
Ownership:	LG&E - 100 %	**Electric Interconnection:**	Paddy's Run CT Substation
Fuel:	Natural gas	**Fuel Supply:**	Contract and spot
Type:	Simple cycle, natural gas fired CT generators	**COD:**	June 1, 1968 (Unit 11/12) June 27, 2001 (Unit 13)
Equipment:	1 x GE 5001LA, 1x Westinghouse W-301-G 1x Siemens V84.3A CTs	**Operator:**	LG&E

Notes:
1. Nominal capacity represents 100 percent of summer net electrical output.
2. Unit 11 black-start capable.

3.3.2 Plant Description and Design

Siting and Real Estate

The Paddy's Run CTs are located on LG&E property that originally hosted a coal plant in Jefferson County. Specifically, it is downriver from downtown Louisville, Kentucky, and located off of Bells Lane near Exit 4 of Highway 264. The road accessing the site goes through a flood control dike and then turns and increases in elevation to get to the top of the flood control dike, which is the same elevation as Unit 13. Unit 11 and 12 are at lower elevations but are behind the flood control dike. An aerial view of PR13 is shown on Figure 3.3-2.

The original coal fired units were decommissioned, but the boiler and powerhouse building and the majority of the original coal unit equipment has not yet been removed from the site or demolished.

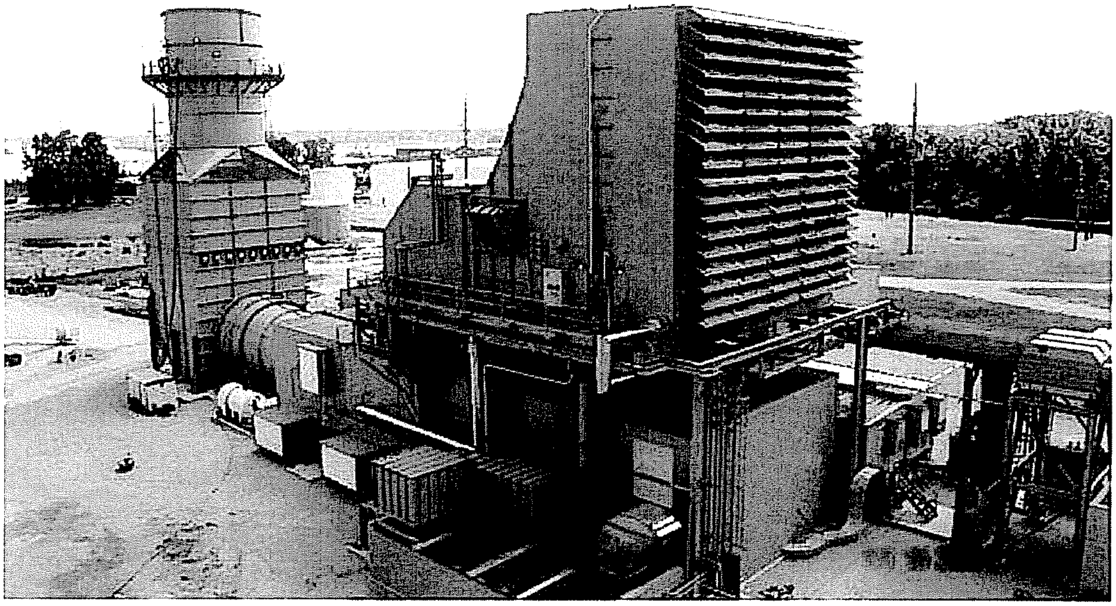

Figure 3.3-2
Paddy's Run Station

Equipment

Table 3.3-2 provides a summary of the major equipment at the Paddy's Run Station. The plant configuration is considered typical of a simple cycle application and includes equipment suitable for power generation applications.

Combustion Turbines

Paddy's Run Unit 11 (PR11) was placed in service in 1968. PR11 major equipment includes a GE 5001LA, natural gas fired, single shaft, axial combustor-style CT, with open ventilated, air-cooled generator, new and clean net summer rated 16 MW; a Cummins V8-300 diesel engine/torque converter drive type starting device rated for 300 hp at 3000 rpm, with Twin Disc 4-S torque converter, for black-start capability; a GE accessory gear box; a GE generator rated for 18,824 kVA and 13,800 V; inlet air filtration; a self-supporting silencer; and a cranking diesel tank. The unit has black-start capabilities.

Table 3.3-2 Paddy's Run Combustion Turbines Major Equipment		
Description	Quantity	Characteristics
CTs	1	GE 5001LA axial combustor style CT. Natural gas fired, rated for 12 MW net summer capacity, black-start capable.
	1	Westinghouse W-301-G, axial combustor style CT. Natural gas fired, rated for 23 MW net summer capacity.
	1	Siemens V84.3A, axial combustor style CT. Natural gas fired, rated for 158 MW net summer capacity.
Generators	1	GE generator rated for 18,824 kVA and 13,800 V, air-cooled
	1	Westinghouse generator rated for 38,400 kVA and 13,800 V, air-cooled.
	1	Siemens Westinghouse water-cooled generator, rated for 200 MVA at 16,000 V, air-cooled
Transformers		GT-11 and GT-12 feed into 13.8 kV system and also used for starting GT-13 in black start
Control Systems		GE, MK, Westinghouse, and Siemens
Natural Gas Supply	1	Gas delivery connection line from gas transmission company at line pressure
	1	Universal compression, centrifugal, motor-driven, building enclosed, natural gas compressor to boost fuel supply to required pressure for V84.3A

Paddy's Run Unit 12 (PR12) was placed in service in 1968. PR12 major equipment includes a Westinghouse W-301-G, natural gas fired, single shaft, axial combustor style CT, with open ventilated, air-cooled generator, new and clean summer net rated 27 MW; a Waukesha L1616 diesel engine/torque converter drive-type starting device rated for 300 hp at 3000 rpm, with Twin Disc Series 11500 torque converter; a Westinghouse generator rated for 38,400 KVA and 13,800 V; inlet air filtration; and a cranking diesel tank.

Paddy's Run Unit 13 (PR13) was placed in service in 2001. PR13 major equipment includes a Siemens V84.3A, natural gas-fired, axial combustor style CT, new and clean net summer rated at 152 MW without inlet cooling; dry low NO_x combustors; a self-contained, closed loop cooling system, with external air-fan heat exchangers; inlet air filtration; a Siemens Westinghouse, water-cooled generator rated for 200 MVA at 16,000

V; a self-contained, closed loop cooling system; a CO_2 based-fired protection system; a self-supported exhaust system with silencer; and a universal compression, centrifugal, motor driven, natural gas compressor to provide fuel supply at the required pressure for the V84.3A.

Fuel Supply

Natural gas is delivered to the site at line pressure. PR 13 requires line pressure to be increased by the onsite gas compressor to the CT gas operating pressure.

Water and Wastewater

Drinking water is supplied by the local municipal system, which also supplies water for use in the evaporative cooler associated with PR13. Deionized water is trucked from Cane Run Station for turbine blade washes. Groundwater from an onsite supply well is used as a source of noncontact cooling water for one of the turbines.

Paddy's Run has a KPDES wastewater discharge permit (Permit. No. KY0002071) issued by the KDEP in 2008 that is effective through June 2013. The permit includes such reporting or monitoring parameters as temperature, flow, and suspended solids.

3.3.3 Performance

Table 3.3-3 shows the historical net generation, CF, EAF, and EFOR for Paddy's Run Station CTs. The table also shows the industry averages for CF, EAF, and EFOR. Industry average data is developed using the GADS database provided by NERC and are for units in the SERC and RFC NERC regions for the years 2000 through 2006. The industry averages are as reported for units between 10 and 20 MW for Unit 11, between 25 and 45 MW for Unit 12, and between 150 and 200 MW for Unit 13.

The CTs at the Paddy's Run facility are operated as peaking units. Even as peaking units, PR11 and PR12 have been operated infrequently in the past 4 years. These two units are more than 40 years old and have heat rates over 15,000 Btu/kWh. According to system outage summaries, PR12 was mothballed between November 2006 and November 2007. The average capacity factor for these units has been less than 1 percent over the last 4 years and is forecast for similar low dispatch in the future. The plan does not account for major overhaul maintenance for these units, and Cane Run has stated a need to evaluate PR11 and PR12 continued long-term viability.

Table 3.3-3
Historical Performance Data for Paddy's Run Station Combustion Turbines

	2004	2005	2006	2007	Average
Unit 11					
Net Generation (MWh)	0	645	813	87	386
Net Heat Rate (Btu/kWh)	0	16,410	19,014	6,048	17,197
Capacity Factor (%)	0.0	0.6	0.8	0.1	0.4
Industry Average CF (%)					*0.5*
Equivalent Availability Factor (%)	99.9	100.0	95.3	N/A	98.4
Industry Average EAF (%)					*89.6*
Equivalent Forced Outage Rate (%)	100.0	-	80.2	94.2	91.5
Industry Average EFOR (%)					*65.8*
Unit 12					
Net Generation (MWh)	0	256	232	0	122
Net Heat Rate (Btu/kWh)	0	27,026	23,725	0	25,457
Capacity Factor (%)	0.0	0.1	0.1	0.0	0.1
Industry Average CF (%)					*2.1*
Equivalent Availability Factor (%)	99.3	95.8	64.2	81.0	85.1
Industry Average EAF (%)					*88.0*
Equivalent Forced Outage Rate (%)	100.0	93.5	99.4	99.5	98.1
Industry Average EFOR (%)					*56.6*
Unit 13					
Net Generation (MWh)	31,324	134,268	88,206	71,491	81,322
Net Heat Rate (Btu/kWh)	9,635	9,772	10,348	10,028	9,971
Capacity Factor (%)	2.3	9.7	6.4	5.2	5.9
Industry Average CF (%)					*4.8*
Equivalent Availability Factor (%)	92.3	98.2	86.3	92.5	92.3
Industry Average EAF (%)					*91.5*
Equivalent Forced Outage Rate (%)	49.8	14.9	78.6	60.6	51.0
Industry Average EFOR (%)					*21.0*

The PR13 dispatch is more frequent than PR11 and PR12, and its 4 year capacity factor has been above the industry average. In accordance with the system outage summaries in 2006, the EAF for PR13 was below industry average primarily because of a planned outage to address gas turbine liner issues. The same documents identify that the EFOR of PR13 has been higher than the industry average in recent years. The EFOR in 2006 and 2007 was primarily because of the unscheduled events reported as gas turbine piping and valve maintenance event and a gas turbine control systems maintenance event.

3.3.4 Operations and Maintenance

Operations

The Paddy's Run CT site is operated and maintained by a group of Cane Run Station personnel. The O&M and capital budgets for these units are included with the Ohio Falls Hydroelectric units.

Outage Management

While PR13 is maintained in accordance with manufacturer's recommendations, including an expected overhaul in 2013, the current plan does not include costs for major overhaul maintenance in accordance with manufacturer's recommendations for PR11 and PR12. This decision is due to low forecasted utilization, declining reliability, and cost to maintain. The exclusion of this work may prevent detection of pending unit problems, slow repair times, increased risk of damage during startup, and further reduce reliability. Cane Run has stated a concern over the evaluation of continued long-term viability of these two CTs.

Plant staff for PR13, manufactured by Siemens-Westinghouse, plans scheduled major maintenance based on EOH. The manufacturer's calculations for EOH adjust the actual operating hours to account for known maintenance factors, including the number of starts, number of trips, hours of operation on oil, and other considerations.

Expenses

O&M costs for the Paddy's Run CTs are included with the Cane Run/Zorn CTs and the Ohio Falls operating budget. The projected operating costs for Cane Run CTs/Paddy's Run CTs/Zorn CTs/Ohio Falls are illustrated in Table 3.3-4.

Table 3.3-4 Paddy's Run and Cane Run Station Combustion Turbines, and Ohio Falls Hydroelectric Generating Station O&M Expenses ($000)					
	2003	2004	2005	2006	2007
O&M		$2,976	$1,844	$1,891	$2,107
Other Cost of Services					
Fuel Handling					
Below the Line					
Total Controllable		$2,976	$1,844	$1,891	$2,107
Net Generation (GWH)		246	329	329	213
Controllable/MWh		$12.10	$5.60	$5.75	$9.89

The Paddy's Run CT portion of the O&M maintenance costs were historically approximately $440,000 per year, shared with the Cane Run/Zorn CTs. The labor budget is shared with the LG&E Cane Run/Zorn CTs and Ohio Falls units and averaged approximately $460,000.

3.3.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Four Black & Veatch engineers visited the station on July 24, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating CT power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil or water, corrosion damage, or other distress. The gas compressor building atmosphere was observed to be approaching or above the natural gas lower explosive level limit. Vapor was noticed liberating from the compressor oil reservoir cover plate, a sign that the compressor seal could be passing. Electrical equipment seemed to have been properly maintained. The undisturbed state of the original Paddy's Run coal fired steam plant equipment and facilities from the retired and abandoned units do not appear to present risk to the remaining operating units

The current maintenance plan does not include any projected costs for major overhaul maintenance (hot gas path inspection) for PR11 or PR12 due to low forecast utilization, declining reliability and cost to maintain. This exclusion of hot path inspections may prevent detection of pending unit problems, slow repair times, increase risk of damage during start up, and further reduce reliability. Cane Run has stated a need for the evaluation of continued long-term viability of PR11 and PR12.

As mentioned above, Paddy's Run gas compressor building atmosphere appeared to be approaching or above the natural gas lower explosive level limit. Cane Run has a planned capital budget of $3.6 million for 2010 that should address this issue. Consideration to the installation of building gas detection instrumentation should be given, in addition to review of the fire or flame detection instruments.

The Paddy's Run capital plan includes overhaul of the PR gas compressor in 2010 for a cost of $3,600,000.

3.3.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.2.3. From the information provided, the existing Paddy's Run Station appears to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

The most significant finding of the environmental review is listed below,

Air

- EON submitted a 2007 Annual Air Compliance Certification indicating compliance with its permit conditions, with the exception of one item. PR12 is subject to the Federal NO_x Budget Trading Program (40 CFR Part 97). A NO_x Budget Application and Certificate of Representation was submitted as required; however, a monitoring plan and annual NO_x Budget certifications were not submitted as required by the program. In March EON submitted three letters to EPA and one to the Air Pollution Control District of Jefferson County for NO_x budget program emission allowance reconciliation, Certification for use of Low Mass Emission Monitoring Methodology in lieu of CEMS, and the initial monitoring plan for Paddy's Run 12. No information regarding a response from EPA or the Air Pollution Control District of Jefferson County regarding the acceptance or potential issue due to the oversight was available for review.

3.3.7 Key Findings

- The 2008 to 2012 budget does not include costs for major overhaul maintenance, in accordance with manufacturer's recommendations for

PR11 or PR12. Plant staff indicated that this is due to low forecasted utilization, declining reliability, and an increased cost to maintain. The exclusion of this work may prevent detection of pending unit problems, slow repair times, increase risk of damage during startup, and further reduce reliability. Plant staff have stated concerns for the evaluation of continued long-term viability of these two CTs.

- The gas compressor for PR13 is leaking natural gas. Plant staff indicated that they have allocated $3.6 million to resolve this issue in 2010. Installing gas detection instrumentation and a review of the fire and flame detection instruments is recommended.

3.4 Cane Run Station Combustion Turbines

3.4.1 Introduction

The LG&E Cane Run Station CTs are located approximately 8 miles southwest of Louisville, Kentucky. Cane Run Station Unit 11 (CR11) is located on LG&E property at the Cane Run coal fired units. Zorn Combustion Turbine Unit 1 (ZN1) is located adjacent to the Louisville Water Company (LWC) pumping station. The site location is illustrated on Figure 3.4-1. Including both units, the turbines have a total declared net summer capacity of 28 MW. The units are used for peaking power supply and dispatch occasionally for portions of the day during periods of high system demand in summer or other peak periods. Both units are black start capable, have been in operation since 1968, and are operated from the Cane Run Plant. Table 3.4-1 provides a summary of facts for the Cane Run Station.

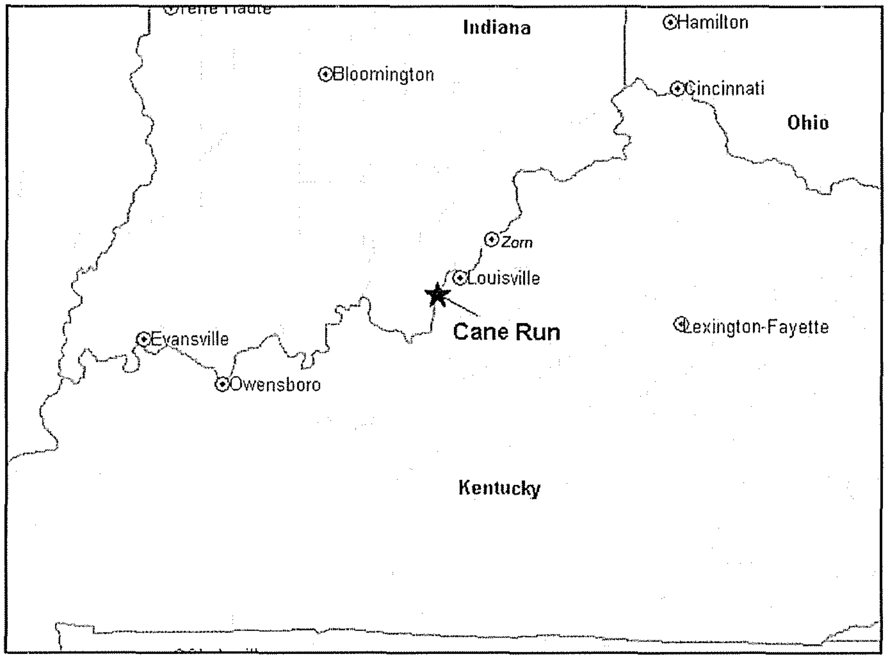

Figure 3.4-1
Cane Run Generating Station Location

Table 3.4-1
Cane Run Station/Zorn Combustion Turbines Fact Sheet

Category	Data	Category	Data
Location:	Jefferson County, KY, 8 miles southwest of Louisville	**Market Area:**	Midwest
Nominal Capacity:	28 MW net summer	**Off-Take:**	EON network customers
Ownership:	LG&E - 100 %	**Electric Interconnection:**	Cane Run CT Substation
Fuel:	Natural gas	**Fuel Supply:**	Contract and Spot
Type:	Simple cycle, natural gas fired CT generators	**COD:**	June 1, 1968 (Cane Run 11) May 1, 1969 (Zorn 1)
Equipment:	1 x Westinghouse W-191G, 1 x GE 5001LA, CTs	**Operator:**	LG&E

Notes:
1. Nominal Capacity represents 100 percent of summer net electrical output.
2. Cane Run and Zorn both black-start capable.

3.4.2 Plant Description and Design

Siting and Real Estate

The Cane Run CTs are located at different sites. CR11 is located on the site of the Cane Run coal fired units, and ZN1 is adjacent to the LWC pumping station at Zorn Avenue and Upper River Road. The Cane Run Generating Station is located at 5252 Cane Run Road (State Highway 1849), approximately 8 miles southwest of Louisville, Kentucky. The facility includes approximately 500 acres between Cane Run Road and the Ohio River. The entrance road is straight and parallels the railroad and power lines. The road will be scheduled to be relocated when the plans for the new landfill are determined.

Equipment

The Cane Run Station CTs include two gas fired CTs, both with black-start capability by cranking diesel engines. The plant major equipment is listed in Table 3.4-2.

Table 3.4-2
Cane Run/Zorn Combustion Turbines Major Equipment

Description	Quantity	Characteristics
CTs	1	Westinghouse W-191-G, axial combustor style CT. Natural gas fired, rated for 14 MW net summer capacity, black-start capable.
	1	GE 5001LA, axial combustor style CT. Natural gas fired, rated for 14 MW net summer capacity, black start capable
CTGs	1	Westinghouse generator rated for 16,320 kW and 13,800 V
	1	General Electric generator rated for 21,176 kVA and 13,800 V
Control Systems		GE, MK, and Westinghouse
Natural Gas Supply	1	Gas delivery connection line from gas transmission company at line pressure

Combustion Turbines

CR11 was placed in service in 1968. CR11 major equipment includes a Westinghouse W-191G, natural gas fired, single shaft, axial combustor style CT, with open ventilated air-cooled generator, new and clean summer net rated 15 MW base; a diesel engine/torque converter drive type starting device for black start capability; a Westinghouse generator rated for 16,320 kW and 13,800 volts; and inlet air filtration.

ZN1 was placed in service in 1969. ZN1 major equipment includes a GE 5001LA, natural gas fired, single shaft, axial combustor style CT; a diesel engine/torque converter drive type starting device for black start capability; a Westinghouse generator rated for 21,176 kVA and 13,800 volts, and inlet air filtration.

3.4.3 Performance

Table 3.4-3 lists key performance indicators for the LG&E Cane Run CTs.

Table 3.4-3
Historical Performance Data for Cane Run Station Combustion Turbines

	2004	2005	2006	2007	Average
Unit 11					
Net Generation (MWh)	33	143	1,179	312	417
Net Heat Rate (BTU/kWh)	34,088	21,340	19,657	32,958	22,576
Capacity Factor (%)	0.0	0.1	1.0	0.3	0.3
Industry Average CF (%)					*0.5*
Equivalent Availability Factor (%)	96.5	64.3	83.8	76.7	80.3
Industry Average EAF (%)					*89.6*
Equivalent Forced Outage Rate (%)	98.6	99.6	72.3	56.5	81.8
Industry Average EFOR (%)					*65.8*
Zorn 1					
Net Generation (MWh)	0	0	0	0	0
Net Heat Rate (BTU/kWh)	0	0	0	0	0
Capacity Factor (%)	0.0	0.0	0.0	0.0	0.0
Industry Average CF (%)					*0.5*
Equivalent Availability Factor (%)	93.2	85.3	92.2	89.1	90.0
Industry Average EAF (%)					*89.6*
Equivalent Forced Outage Rate (%)	52.9	74.2	58.8	24.0	52.5
Industry Average EFOR (%)					*65.8*

ZN1 has not been dispatched in the last 4 years, while CR11 has operated infrequently. This is mainly due to the unit's age and high operating heat rates. The unit's average capacity factor has been less than 1 percent over the last 4 years. Additionally, the plan does not account for major overhaul maintenance for these units, and Cane Run has stated the need for an evaluation of its continued long-term viability.

3.4.4 Operations and Maintenance

The LG&E Cane Run Station CTs are operated and maintained by a group of Cane Run Station personnel.

Outage Management

Since the viability of the units is currently under consideration, the current plan does not include costs for major overhaul maintenance, in accordance with manufacturer's recommendations for CR11 and ZN1. This exclusion of hot path inspection may prevent detection of pending unit problems, slow repair times, increase risk of damage during startup, and further reduce reliability.

O&M Historical Expenses

O&M costs for the Cane Run Station/Zorn CTs are included with the Paddy's Run CTs and the Ohio Falls operating budget and are illustrated in Table 3.4-4. The O&M maintenance costs for the Cane Run/Zorn CTs were historically approximately $440,000 per year, and are shared with the Paddy's Run CTs. The labor budget is shared with the Paddy's Run CTs and Ohio Falls units, and averaged around $460,000.

Table 3.4-4
Paddy's Run and Cane Run Station/Zorn CTs, and Ohio Falls Hydroelectric Generating Station O&M Expenses

	2003	2004	2005	2006	2007
O&M ($000s)		$2,976	$1,844	$1,891	$2,107
Other Cost of Services					
Fuel Handling					
Below the Line					
Total Controllable ($000s)		$2,976	$1,844	$1,891	$2,107
Net Generation (GWH)		246	329	329	213
Controllable/MWh		$12.10	$5.60	$5.75	$9.89

3.4.5 Equipment Condition

Black & Veatch visited the Cane Run plant, but did not visit the ZN1 facilities to perform visual assessments. Since the continued viability of CR11 and ZN1 is currently under consideration, equipment other than the CTs of these units was not reviewed in detail by Black & Veatch. It still should be noted that, the exclusion of hot path inspection in the operations plan may prevent detection of pending unit problems, slow repair times, increase risk of damage during start up, and further reduce reliability of these units.

3.4.6 Environmental

The environmental review was based on documents provided by EON and from observations from Black & Veatch staff who visited the facility in July 2008. From the information provided, the existing Cane Run Station CTs appear to have in place the required environmental permits and to be operating in substantial compliance with permit and regulatory requirements.

3.4.7 Key Findings

The 2008 to 2012 budget does not include costs for major overhaul maintenance in accordance with manufacturer's recommendations for CR11 and ZN1. Plant staff indicated that this is due to low utilization according to the forecast, declining reliability, and maintenance costs. The exclusion of this work may prevent detection of pending unit problems, slow repair times, increase risk of damage during startup, and further reduce reliability. Plant staff have stated a concern for the evaluation of continued long-term viability of these CTs.

4.0 Hydroelectric Generating Plants

4.1 Ohio Falls Hydroelectric Generating Station

4.1.1 Introduction

The Ohio Falls Hydroelectric Generating Station (Ohio Falls) is located in downtown Louisville, Kentucky, on the Ohio River. The site location is illustrated on Figure 4.1-1. Ohio Falls has eight "Run of the River" units that began commercial operation in January 1928. The station is located adjacent to the US Army Corps of Engineers (USACE) McAlpine Locks and Dam.

The Ohio Falls "Run of the River" units generate a capacity of 80 MW. Water allocations into the station are based on the river levels and are controlled by the USACE. In 2005, the units began rehabilitation to increase capacity efficiency, and when completed in 2013, it is anticipated that the eight units will generate a total capacity of 101 MW. Table 4.1-1 provides a summary of facts related to Ohio Falls.

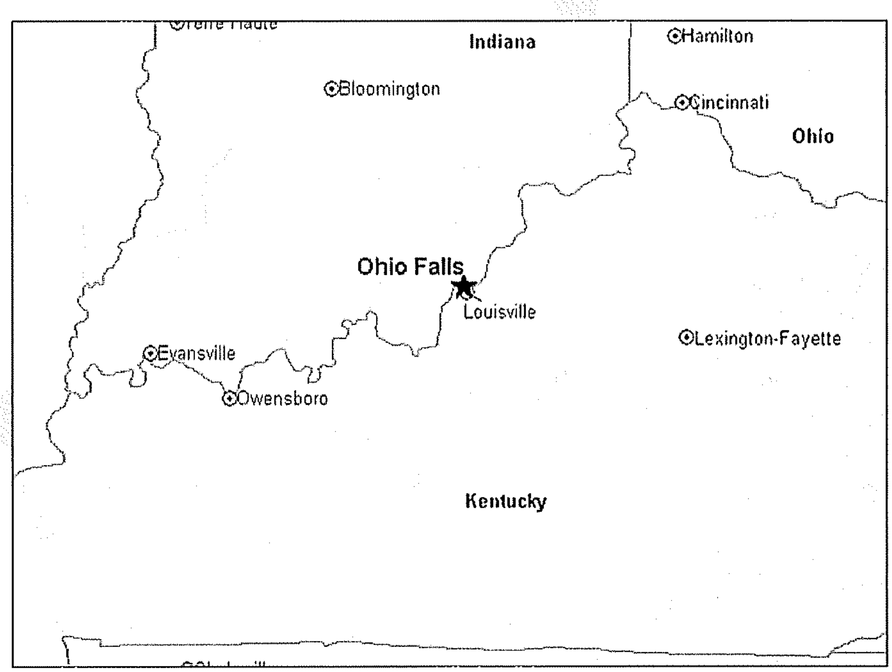

Figure 4.1-1
Ohio Falls Generating Station Location

Table 4.1-1 Ohio Falls Hydroelectric Plant Fact Sheet			
Category	**Data**	**Category**	**Data**
Location:	Louisville, KY	**Market Area:**	Midwest
Nominal Capacity:	80 MW net (current) 101 MW net (post-upgrade)	**Off-Take:**	EON network customers
Ownership:	LG&E - 100%	**Electric Interconnection:**	Ohio Falls Substation
Fuel:	N/A	**Fuel Supply:**	N/A
Type:	Hydroelectric	**COD:**	January 1, 1928
Equipment:	8 x hydro-turbine generators	**Operator:**	LG&E
Notes: 1. Capacity represents 100 percent of average (winter, summer) net electrical output.			

4.1.2 Plant Description and Design

Siting and Real Estate

Ohio Falls is located on N 27th Street in downtown Louisville, Kentucky, on the Ohio River and is adjacent to the falls of Ohio State Park. Figure 4.1-2 shows an aerial view of the station. Ohio Falls is located on the Ohio Falls Dam, built in 1925 by the USACE to help control the Ohio River water level and to monitor the flow through the City of Louisville. Access to Ohio Falls is through N 27th Street, across a newly built bridge that expands across the USACE McAlpine Locks.

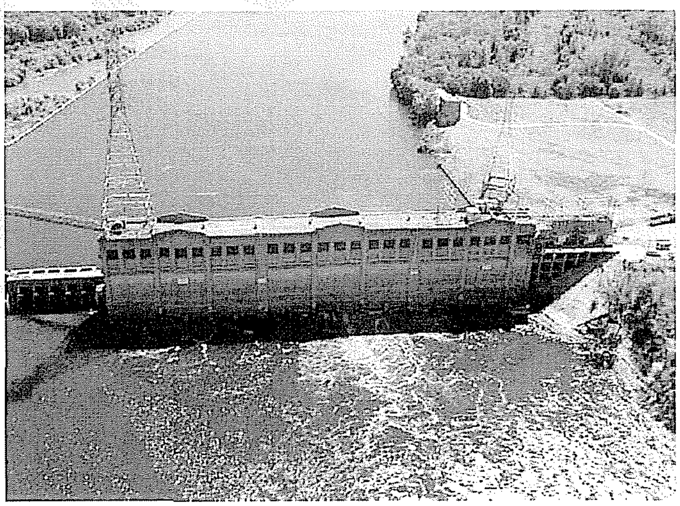

Figure 4.1-2
Ohio Falls Generating Station

Equipment

Ohio Falls is equipped with eight nameplate 10 MW machines with black-start capability, and together, is the largest hydroelectric station in the LG&E system. A rehabilitation project was approved in 2005 to upgrade major components of each unit and to increase production output to approximately 12.7 MW per unit. The project is expected to be completed in 2013. Table 4.1-2 identifies the plant's major capital equipment.

Table 4.1-2
Ohio Falls Hydroelectric Major Equipment

Description	Quantity	Characteristics
Hydro Turbines	8	10 MW hydro-electric turbines commissioned in 1928. Currently in process of upgrade project (2007-2013) to increase capacity to 12.7 MW each.
Hydro Turbine Generators	8	General Electric, 14 kV, 12.55 MVA, being upgraded to 14.68 MVA
Transformers	2	Two 67.2 MVA GSUs for two common collector generator buses
Control Systems		Project is currently upgrading to digital controls by Voith Siemens Hydro (VSH)

Water and Wastewater

All water serving the plant is from the Ohio River; the plant has no groundwater wells installed. Potable water for the facility is supplied by the Louisville Water Company.

Ohio Falls has a KPDES wastewater discharge permit (KY0002089), effective July 1, 2008, and expires on July 30, 2013. The KPDES permit authorizes the discharge of noncontact cooling water, storm water runoff, sanitary wastewater, and generator cooling water into the Ohio River.

4.1.3 Performance

Ohio Falls units have a long and proven operating history. The station has been successfully operated and maintained since project construction.

The Ohio Falls performance indicators for the planning period are shown in Table 4.1-3.

Table 4.1-3
Historical Performance Data for Ohio Falls Hydroelectric Generating Station

	2004	2005	2006	2007	Average
Net Generation (MWh)	214,785	194,203	239,852	140,996	197,459
Capacity Factor (%)	30.5	27.7	34.2	18.9	27.8

Ohio Falls units are "Run of the River," and therefore, water flow is controlled by the USACE. The units operated at an average 32 percent capacity factor from the period 2000 to 2007. Considering the increased capacity resulting from the overhaul plan gain of 2.7 MW at one unit per year from 2007 to 2013, the Ohio Falls capacity factor is planned to increase to a high of 41 percent in 2012. Black & Veatch has not reviewed detailed water throughput estimates from the USACE.

4.1.4 Operations and Maintenance

The Ohio Falls rehabilitation is a multiyear project to upgrade and rehabilitate each of the eight existing turbine/generator units including installation of newly designed runners, new discharge rings, rehabilitation of wicket gates, and new stator windings. Most major systems will either be replaced or rehabilitated on each of the eight units. One unit will be rehabilitated each year of the plan from 2005 to 2012.

O&M Expenses

Ohio Falls O&M costs are included with the operating budget of the Paddy's Run CTs and LG&E Cane Run CTs. The projected operating costs for Paddy's Run CTs/LG&E Cane Run CTs/Ohio Falls are outlined in Table 4.1-4.

Table 4.1-4
Paddy's Run and Cane Run Station Combustion Turbines, and Ohio Falls Hydroelectric Generating Station O&M Expenses ($000)

	2003	2004	2005	2006	2007
O&M		$2,976	$1,844	$1,891	$2,107
Other Cost of Services					
Fuel Handling					
Below the Line					
Total Controllable		$2,976	$1,844	$1,891	$2,107
Net Generation (GWH)		246	329	329	213
Controllable/MWh		$12.10	$5.60	$5.75	$9.89

The O&M maintenance costs for Ohio Falls historically averaged around $295,000, and water fees averaged around $460,000. The labor budget is shared with the Paddy's Run and Cane Run CTs and averaged around $460,000 for the planning period.

4.1.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Four Black & Veatch engineers visited the station on July 24, 2008. The facility appeared to be in good condition. The quality of housekeeping was typical of many operating hydroelectric power plants. The mechanical equipment and structures visually observed during the site tour appeared to be in good condition, with no signs of significant leakage of oil, water or steam, corrosion damage, or other distress. The dam structure was in good condition. Electrical equipment seemed to have been properly maintained. One of the recently modified units was out of service during the site visit due to a cracked valve and flange where the cooling water supply piping penetrates through the dam wall. Repair method and potential redesign had not yet been determined at the time of the site visit. Because this issue has the potential to affect the remaining units, plant personnel noted EON was working diligently to resolve the issue as soon as practical. The other modified units appeared to be in good operating condition.

Hydro Turbines

The hydro turbines major maintenance mainly includes work performed on the unit liner and runner systems. The O&M budget includes approximately $1,300,000 per year for the Ohio Falls Station unit maintenance and other costs. This level of funding typically has included the overhaul of one or two of the units, as well as rebuilding of lower guide-bearings.

The capital overhaul project is currently contracted to Voith-Siemens, who have completed two units and have provided significant maintenance services in the past. Potential alternative bidders are being considered for the rehabilitation of the units in the later years in order to ensure competitive project pricing.

One of the recently modified units was out of service during the Black & Veatch inspection due to a cracked valve and flange where the cooling water supply piping penetrates through the dam wall. Repair method and potential redesign had not yet been determined.

Balance-of-Plant and Electrical

Ohio Falls' dam structure is in generally good condition. During the multiyear project to upgrade and rehabilitate each of the eight existing turbine/generator units, the concrete associated with each unit is being dewatered, inspected, and repaired as required to increase the useful life of the station. The movement of the station is also being monitored on a regular basis.

Ohio Falls has taken preventive measures to mitigate fire damage at the generators by equipping all units with fire detection equipment (UV/IR) that will alert operating personnel to take corrective action.

Ohio Falls' sump pump rooms include a normal motor driven pump and a diesel engine driven stand-by pump. The sump pumps discharge into a relatively small containment that is checked for any oil content, after which time it is drained into the river.

Ohio Falls' controls went through a major upgrade in 2001, in order to maintain the FERC license and to become more efficient in the operation of the station, the largest renewable energy resource in the regulated utility fleet. The upgrade consisted of engineering design, procurement, and installation of equipment for automating the eight units at the plant with sufficient instrumentation to permit remote operation of the units.

The automation system included a complete plant control system designed to meet the requirements of safely operating the plant remotely. Items included in the scope of work included: (1) fully automated plant control system, including the communications highways between major control devices with PLC cabinets of standardized design for ease of operation and maintenance, (2) a new digital unit controller and governor for each turbine generator unit whose function is to sequence all start and stop operations, provide all alarming and shutdown functions, and provide the governor characteristics necessary to maintain unit speed and aid in grid frequency stabilization, (3) plant services controller for monitoring of the station sump pumps, station fire protection, and dissolved oxygen, and (4) SCADA software to operate the eight units in the plant. All plant controls were implemented to be available both locally at the units and at the remote operations centers.

4.1.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.3.1. From the information provided, Ohio Falls is in compliance with its FERC license, conditions, and articles, and with the conditions of its individual permits.

4.1.7 Key Findings

- A rehabilitation project was approved in 2005 to upgrade major components of each of the eight 10 MW units and to increase production output to approximately 12.7 MW per unit. The project is expected to be completed in 2013.
- The station has a FERC license and is in substantial compliance with all conditions and articles of the license.
- The station is subject to a FERC consultant safety inspection every 5 years. The most recent inspection was performed in May 2008, with no significant issues identified, and no additional costs are included in the plan to address any future projects related to inspection results.

4.2 Dix Dam Hydroelectric Generating Station

4.2.1 Introduction

The Dix Dam Generating Station is located approximately 5 miles northeast of Burgin, Kentucky, on the shores of Herrington Lake. The site location is illustrated on Figure 4.2-1. Dix Dam has three "Run of the River" units that began operation in November 1925. The station is located adjacent to the E.W. Brown Generating Station.

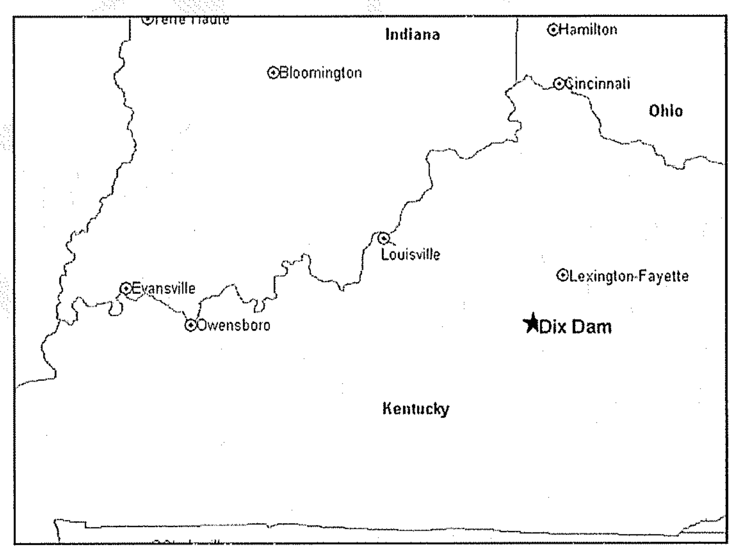

Figure 4.2-1
Dix Dam Generating Station Location

The Dix Dam "Run of the River' units generate a capacity of 24 MW. The units are scheduled to be rehabilitated to increase capacity efficiency, and when completed in 2010, it is anticipated that the three units will have a total capacity of 28 MW. Table 4.2-1 provides a summary of facts related to the Dix Dam Station.

Table 4.2-1
Dix Dam Hydroelectric Station Fact Sheet

Category	Data	Category	Data
Location:	Burgin, KY	**Market Area:**	Midwest
Nominal Capacity:	24 MW net (current) 28 MW net (post-upgrade)	**Off-Take:**	EON network customers
Ownership:	KU - 100 %	**Electric Interconnection:**	Dix Dam Substation
Fuel:	N/A	**Fuel Supply:**	N/A
Type:	Hydroelectric	**COD:**	November 1925
Equipment:	3 x hydro-turbine generators	**Operator:**	KU

Notes:
1. Capacity represents 100 percent of average (winter, summer) net electrical output.

Dix Dam's electrical interconnection is through the E.W. Brown CT Substation and provides power to the electric grid only in situations when heavy rainfalls has resulted in an above normal reservoir water level.

4.2.2 Plant Description and Design

Siting and Real Estate

The Dix Dam Hydroelectric Generating Station is located approximately 5 miles northeast of Burgin, Kentucky, at the head of Herrington Lake. Dix Dam straddles the county line between Mercer County and Garrard County, Kentucky. Access to the Dix Dam is through the E.W. Brown Generating Station. The E.W. Brown Generating Station has a single access road, State Hwy 342, off of State Hwy 33. Figure 4.2-2 shows an aerial view of the station.

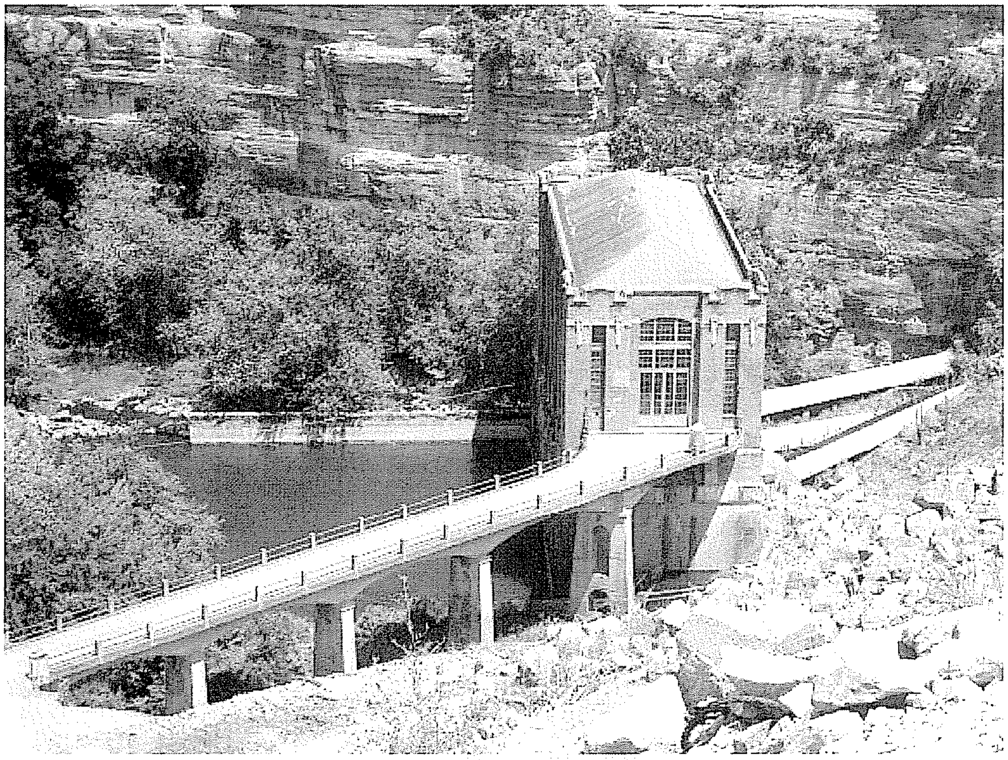

Figure 4.2-2
Dix Dam Generating Station

Equipment

There are three hydroelectric turbines at Dix Dam, which currently produce a net output of 8 MW each. The nameplates indicate that the design capacity, established at the 1938 modification, should be 9.7 MW each. The Dix Dam Station is capable of producing 24 MW of power from its three generator units. Table 4.2-2 identifies the plant's major capital equipment.

Dix Dam hydroelectric plant serves as one of two means of black start power for the E.W. Brown Station, the other being the Haefling CT units. Dix Dam is also significant in that the impounded Herrington Lake provides the raw water source for the E. W. Brown Generating Station.

Water and Wastewater

Herrington Lake is owned and controlled by KU. Herrington Lake is a recreational water resource and warm water aquatic habitat; it also provides water for the city of Danville. Herrington Lake also is the water supply for the E.W. Brown Generating Station.

Table 4.2-2 Dix Dam Hydroelectric Generating Station Major Equipment		
Description	Quantity	Characteristics
Hydro Turbines	3	8 MW hydro-electric turbines commissioned in 1925. Currently in process of upgrade project (2007 to 2013) to increase capacity over 9 MW each.
Hydro Turbine Generators	3	Allis-Chalmers, 13.2 kV, 9.4 MVA.
Transformers		Westinghouse, 13.2 kV-69 kV, 7.5/8.4 MVA OA, 9.375/10.5MVA FA, 55/65C.
Control Systems		Mechanical ball governor; project is planned for upgrades to digital governor control.

Sanitary wastes at the station are tanked and privately contracted to a treatment facility.

4.2.3 Performance

The Dix Dam Station has been in reliable operation for more than 80 years and was originally utilized as a principal source of power for KU. Now the hydroelectric generating plant is used mainly when heavy rainfalls result in above normal reservoir water levels. The generating station is used for flood control. The USACE provides direction for spilling water during flood conditions on the Kentucky River. The Dix Dam hydroelectric unit historical net generation and capacity factor are shown in Table 4.2-3.

Table 4.2-3 Historical Performance Data for Dix Dam Hydroelectric Generating Station					
	2004	2005	2006	2007	Average
Net Generation (MWh)	94,610	36,579	47,026	35,068	53,321
Capacity Factor (%)	45.0	17.4	22.4	16.7	25.4

The Dix Dam hydroelectric units are dispatched according to the water level of Herrington Lake, for flood control.

The units operated at an average 24 percent capacity factor from the period 2000 to 2007. Considering the increased capacity resulting from the overhaul plan gain of more than 1 MW at one unit per year from 2009 to 2010, the Dix Dam hydroelectric station capacity factor is planned to be 22 percent through 2012. Black & Veatch has not reviewed detailed water throughput estimates from the USACE. However, the predicted levels of capacity factors for 2008 to 2012 appear to be reasonable, based upon historical performance.

4.2.4 Operations and Maintenance

The Dix Dam hydroelectric station units and associated dam infrastructure are operated and maintained by E.W. Brown Generating Station personnel. No significant O&M maintenance budget line item costs are identified as assigned to the Dix Dam units.

The projected operating costs for the Dix Dam units are not tracked or budgeted outside of the context of E.W. Brown Generating Station. Therefore, the nonfuel O&M costs are not reported here.

4.2.5 Equipment Condition

Black & Veatch personnel traveled to the facility to interview plant management, review records and equipment reference information, and perform a walkdown and visual assessment of the plant. Two Black & Veatch engineers visited the station on July 17, 2008. The facility appeared to be generally in good condition. The quality of housekeeping was typical of many operating hydroelectric power plants. The hydroelectric turbines were noted as scheduled for repairs. The powerhouse structure was visually observed during the site visit to be in good condition for a structure of this age, with no visible areas of distress or concern noted. The Dix Dam was observed to have some leakage. The plant personnel noted that the issue has been studied, and it is not of a significant concern at present time. The concrete facing of the Dix Dam was visually observed to have an uneven surface, with some surface waviness and distortions. The spillway and gates were observed to be in good condition, with no obvious signs of distress. Electrical equipment seemed to have been properly maintained.

Based on a report prepared by White Engineering Consultants in 2005, the Dix Dam Hydroelectric generating station could provide another 80 years of service, but not without significant investment. Dix Dam is virtually unchanged from its original configuration and is nearing the end of its useful life. The conclusion reached in this report was that there is potential for failure, potentially catastrophic failure of station generating and hydraulic components due to the effects of 80 years of wear and tear on equipment and hydraulic structures. The capital plans include funds for major rehabilitation of the Dix Dam Hydroelectric generation units.

Hydro Turbines

The Dix Dam hydroelectric turbines were found to be in need of repair by the White Engineering Consultants report in 2005, with many key components receiving little attention for decades. Accordingly, the capital planning period for 2008 to 2012 includes an overhaul of each of the three units. The project is intended to upgrade each unit net output from current operating rating of 8 MW each, closer to the design capacity established at the 1938 modification of 9.7 MW each. The project scope at each unit will include new runners, wicket gates, generator core, generator windings, exciter, and controls.

Further work is also planned in 2010 at the Unit 2 shutoff control valve (Johnson Valve). This item is included in the plan to be refurbished to original tolerances due to its current failed condition that requires human intervention to operate. Previous project work for these valves on Units 1 and 3 was completed in 2005 to 2007.

Balance-of-Plant Equipment

The Dix Dam is a rock fill dam. The rock filled dam is 275 foot high and 1,010 feet long. These types of dams are constructed by dumping broken rock and are naturally porous. To retain water in the impoundment, an impervious facing is constructed on the upstream face of the dam. For Dix Dam this facing is concrete. One of the typical issues with rock dams are that they naturally settle under their own weight. This settlement can cause cracks and breaks in the facing concrete slab that can lead to water seeping through the dam.

In the case of Dix Dam, the dam has experienced issues with leakage since its completion. At times there has been more significant leakage experienced that has required attention. Various means have been used to alleviate the leakage,, such as dumping cinders on the face of the dam, placing grout bags over the leaking joints, grouting sections of the dam, and repairing joints and sections of the concrete facing.

The most recent evaluation report concerning the leakage of the Dix Dam was completed by Arcadis in draft form in April 2008. The reported outlined that the principal areas of the dam where leakage has occurred are the power tunnel, the east abutment, the concrete face slab, and the west abutment. The report concluded that the power tunnel, which 60 years ago had a very significant leak and was repaired, showed no evidence of being a concern at this time. It also reported that the east abutment currently is not a concern. The report stated that the principal concern for when the water is at higher levels is leaking through the concrete facing slab. When the lake is at lower elevations, the west abutment will be the most significant leak source.

The concern about leakage flows through Dix Dam was brought to the forefront in 2007 following a USGS survey that indicated possible excessive flow. The plant operating staff explained that if the dam leakage rate exceeds 100 cubic feet per second that this would trigger the need to perform some means of staunching the flow.

The Arcadis investigation, in summary, concluded that the present leakage rate from the dam is not unprecedented, nor currently excessive, and that there is at present no evidence of any rapid changes or other concerns indicating any significant structural risk to the dam. The present plan for the rock dam is to continue to monitor the dam leakage rate to ensure there is no further change.

The report does state that if a severe multiyear drought were to occur, even the current, albeit minor, leakage rate could, under that drought situation, be a significant risk to the water supply for the city of Danville and the E.W. Brown Generating Station.

The planning assumption has been that the Dix Dam leakage rate will not increase to 100 cubic feet per second, which would trigger the need to correct the leakage rate according to permitting requirements. The current capital plan for the generating equipment inside the Dix Dam Hydroelectric Generating Plant includes restoration the generating equipment over the next few years (2010). It is unclear whether these restorations will be approved. If the generation equipment is restored, it would be reasonable to expect that the water levels behind Dix Dam would be maintained at the higher elevations more frequently. If the generation equipment restorations are approved, the capital plans for the Dix Dam should also include funding to restore the concrete facing and to re-grout the east abutments. If the generation restorations are not approved, capital plans should consider including funding for the concrete facing and east abutment grouting so as to maintain the water source for E.W. Brown during drought conditions.

4.2.6 Environmental

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review and detailed review findings are provided in Appendix B.3.2. From the information provided, Dix Dam does not require a FERC license and does not require additional permits or approvals.

4.2.7 Key Findings

- The Dix Dam hydroelectric turbines were found to be in need of repair by the White Engineering Consultants report in 2005, with many key components receiving little attention for decades. Accordingly, the capital planning period for 2008 to 2012 includes an overhaul of each of the three units, at a budgeted cost of $18 million. The project is intended to upgrade each unit net output from the current operating rating of 8 MW, closer to the design capacity of 9.7 MW established during the 1938 modification.

- Currently, the facility is not required to have a FERC license. It is possible that FERC could require a license sometime in the future, but FERC currently has no plans to pursue the license issue with EON.

5.0 Trimble County Unit 2 Development

5.1 EPC Contract Review

Black & Veatch reviewed the EPC Contract for the TC2 Project, which was entered into as of June 9, 2006, between the Owners (LG&E, KU, IMPA, and IMEA) and the Contractor (Bechtel Power Corporation). The scope of the Contractor is to design, engineer, procure, construct, start up, commission, and test the facility as set forth in the contract. The Owners have vested LG&E and KU with the authority, as agents of the Owners, in the administration and management of the contract. The provisions in the TC2 EPC contract are typical of an EPC coal fired generating plant contract signed during the 2005 and 2006 time period.

According to the contract data, TC2 is designed and built to generate a guaranteed net plant output of 760.5 MW while burning the performance fuel, a blend of 70 percent eastern bituminous coal and 30 percent western sub-bituminous coal. TC2 will be a highly efficient, pulverized coal fired, supercritical unit. The steam turbine will use 3,690 psi, 1,075° F steam at the throttle and 1,075° F steam at the reheat inlet, and an eight feedwater heater cycle to generate a gross output of 809.3 MW. The plant auxiliary load has been guaranteed to be 48.8 MW.

5.1.1 Assessment of Guarantees and Liquidated Damages

The EPC contract has guarantee requirements and liquidated damage (LD) clauses that are typical of such contracts. The contract has guarantees and provisions for LDs for delay in tie-in with TC1 and commercial operation delay; performance LDs for failure to achieve net electrical output, net heat rate, and guaranteed ammonia and limestone consumption; and reliability LDs for failure to pass the reliability test. The major guarantees in the EPC contract are listed as follows:

- Guaranteed Commercial Operation Date: June 15, 2010.
- Guaranteed Final Completion Date: March 12, 2011.
- Guaranteed Net Electrical Output: 760.5 MW.
- Guaranteed Net Heat Rate: 8,662 Btu/kWh.
- Guaranteed Ammonia Consumption: 593 lb/h.
- Guaranteed Limestone Utilization Ratio: 97 percent.

The guaranteed net heat rate of 8,662 Btu/kWh and the auxiliary power of 48.8 MW appear to be quite aggressive. Even considering the highly efficient supercritical cycle and the use of the natural draft cooling tower, which does not require fan power, these values may not provide much margin.

The LD provisions for the contract are as follows:

- Tie-In Delay: $350,000 per service day in June, July, and August, and $210,000 per service day in the other months of the year.
- Commercial Operation Delay: $200,000 per day for the first 60 days and $300,000 per day thereafter.
- Low Output: $1,600 per kW missed output.
- High Heat Rate : $175,000 per Btu/kWh missed heat rate.
- High Ammonia Use: $23,800 for each lb/h of additional ammonia.
- High Limestone Use: $250,000 for each 1 percent of additional limestone utilization.
- The Maximum Limit of LDs: 30 percent of the Basis of Caps (Basis of Caps = $7.7 million less than the contract price).
- The Maximum Limit of Overall Liability: 40 percent of the Basis of Caps.

The amounts of LDs for each of the above items are consistent with typical industry practice.

The procedure for the performance tests, to verify performance guarantees, is given in Exhibit I of the Contract. The procedure is not the detail test procedure, but provides the general guidelines and the industry test code requirements that are to be followed. The test correction curves were not included in the procedure. It is expected that they will be included in the detailed performance test procedure at least 4 months prior to the commencement of the performance tests by mutual agreement between the Owners and the Contractor. The performance test requirements in the contract, in general, are consistent with standard industry practice. The detail performance test procedure should be mutually agreed upon so that the test results can be accurately measured, corrected, and established.

5.1.2 Contract Cost and Budget

It is difficult to predict the potential for change order requests by the Contractor, which would increase the total contract price. However, this contract does have provisions that are predictable. One of the provisions is relief to the EPC Contractor with regard to changes from the base period in highly skilled and skilled craft wage rates and daily per diem. Paragraph 8.15 allows adjustment either between the skilled wage rate required to be paid by craft category by the Contractor to the "Base Labor Rate," which will be escalated by 3 percent per year from 2006, or actual wages that had been paid by craft categories at other LG&E and/or KU major projects for the period. The Contractor is entitled to an adjustment in the contract price based on the lesser of the amount between the craft rate paid by the Contractor or paid at other major KG&E/KU projects. Similarly, adjustment in the actual per diem paid compared to base daily adjusted rate entitles the Contractor adjustment in the contract price.

The Owners provide to the Contractor, after January 1 and July 1 each year, the highest average major project labor rate for each craft category, the per diem rate, and the shortest per diem distance, in order for the Contractor to determine any adjustments. For 2007, the requested adjustment for change in craft labor rates and per diem, amounted to \$1.5 million; this amount is still under review. Beyond the end of 2007, the Contractor will expend considerable more skilled craft hours than the hours prior to January 1, 2008. To attract skilled craft, wage rates and per diems paid will be higher than the 3 percent adjusted 2006 base wage and \$40 per day per diem. Therefore, the requested adjustment amount is expected to be higher than the previous sum.

Another unique provision, in which the Contractor has already received a change order, is changes in the boiler quantities between the "Baseline" and "Final" quantities times the applicable unit rate. The total aggregate value shall not exceed \$3,000,000, which is the amount of the change order.

The contract also has provision for the Contractor to be reimbursed for any sales tax paid. Through the fourth quarter of 2007, the total approved amount is \$342,169 on approximately 53 percent of the contract price. Therefore, the impact on the final contract price is expected to be relatively minor.

The total approved scope change amount as of June 2008, when 29.8 percent of the overall project was complete, was about \$1.5 million. The cost of the project has been very close to the budget until now. Although the scope change amount is low, there is potential of much higher rate of scope change and adjustments during the next very aggressive part of the schedule. At this time, it is difficult to predict by how much the cost will increase.

5.1.3 Contract Schedule

In the June 2008 monthly report, the Contractor stated that the target schedule for completion has moved by 1 month to April 15, 2010. One month later, the schedule was revised. There was no mention if the guaranteed completion date of June 15, 2010 has been impacted. The reasons provided were labor availability, crane downtime, and inclement weather. Similar schedule impacts are known to have been experienced recently on other similar coal projects.

The monthly report mentions two critical paths, one through the boiler and the other through the turbine. The path through the boiler is currently impacted by the delay in erecting the boiler steel. The delay in receiving the CRV to December 2008 may impact the second critical path; secondary critical paths may be occurring in the near future. The project percent completed as of June 2008 is 29.8 percent, which is only a 1.5 percent increase from the previous month. The percent complete progress curve indicates a project percent complete of approximately 84 percent for the boiler hydro in April 2009. Therefore, over the next 10 months, the Contractor has to achieve a monthly an average of 5.4 percent. While this may be achieved for an individual month, the likely average rate will be closer to 3 to 3.5 percent. This opinion is also supported by one of the reasons given for the 1 month delay of labor shortage. Therefore, the construction progress should be closely monitored.

5.2 Projected Performance and Operating Budgets

The TC2 design guarantee commercial operation performance is 760.5 MW net output and 8,662 Btu/kWh net heat rate. The following are the 2010 through 2012 planned key performance indicators for TC2.

TC2 (100%)		2010	2011	2012
Net Generation	MWh	2,986,746	5,697,616	5,942,714
Fuel Consumed	Tons	1,251,094	2,374,659	2,476,768
Fuel Consumed	MMbtu	26,801,432	50,497,521	52,664,450
Net Heat rate	BTU/KWh	8,973	8,863	8,862
EAF	Percent	81.8	85.5	89.2
Capacity Factor	Percent	44.8	85.5	89.2
EFOR	Percent	3.30	3.30	3.30
MOF+POF	Percent	14.9	11.2	7.50
Avg Coal Htg. Val	Btu/lb	10,711	10,632	10,632

The planned amount of degradation on heat rate (2 percent through year 2012) appear achievable for this unit, assuming that the unit meets commercial operation guarantees without the application of excessive test tolerances. Degradation should be applied to actual unit performance, plus any excluded BOP auxiliaries such as limestone grinding and material handling.

It is usually common for new coal units to experience higher number of forced outages due to new plant break-in issues in the first few years of commercial operation. As such, Black & Veatch is of the opinion that the projected EFOR for TC2 of 3.3 percent for the first 3 years appear to be optimistic, but achievable. A projected EFOR in the 4.0 percent to 8.0 percent range for the first few years of operation for a new pulverized coal unit is considered more reasonable.

The projected EAFs of 81.8 percent in 2010 and 85.5 percent in 2011 for TC2 appear to be reasonable. However, the projected EAF of 89.2 percent in 2012 is considered slightly optimistic, but achievable. The projected CFs of 85.5 percent in 2011 and 89.2 percent in 2012 are considered too aggressive, because these projected CFs numbers are the same as the projected EAFs numbers. Black & Veatch is of the opinion that in the best case scenario where a baseload coal plant is given the top dispatch order, its CF number is still likely going to be 1 percent to 3 percent below its EAF number for the same year.

There is no capital major maintenance budget for TC2 included in the planning period from 2008 to 2012 outside of the initial project construction capital. The TC2 operating costs are included in the O&M budget for the Trimble County Station overall budget, which includes TC1 and TC2 operating costs. Black & Veatch review of the Trimble County Station overall projected operating costs found that the projected costs are reasonable.

Organization charts were not provided, but the total headcount for the station (111 in 2008) appears consistent with industry practice in light of the fact the plant has substantial emissions control equipment and a compliment of gas turbines at the same site. The stated plans for staff increases as TC2 comes online appear to be reasonable for the combined facilities.

5.3 Review of Permit Status and Regulatory Compliance

The permits required for the construction and operation of TC2 were identified by EON and in the Licensing Assessment prepared in 2004 by Black & Veatch. The status of each of these permits is provided in the following paragraphs.

5.3.1 Permits Required for Construction

The following permits and approvals may be required, or may require modification, prior to the start of construction of Unit 2.

Federal

Federal Aviation Administration (FAA) - Notification of Construction (Boiler Building and Construction Cranes)

FAA approval for the boiler building was received on September 28, 2006, and for the construction cranes on July 18, 2007.

State

Kentucky Public Service Commission (KPSC) - CPCN/SCC

LG&E was required to obtain a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate (CPCN) from the KPSC prior to the expansion of TC1.

On November 1, 2005, EON was granted a CPCN to construct a 750 MW super-critical, pulverized coal baseload unit, TC2, at LG&E's Trimble County Generating Station (Reference KPSC Case Number 004-00507).

KDEP - State Air Permit to Construct

The existing air emission sources at the Trimble County Station include a 500 MW PC generating unit (TC1), six 150 MW simple cycle natural gas CTs, a natural draft cooling tower, coal/limestone/ash handling equipment, and fuel oil storage tanks. The existing natural draft cooling tower, coal/limestone/ash handling equipment, and fuel oil storage tanks will have increased utilization when TC2 becomes operational. In addition to TC2, the new equipment proposed will include a linear mechanical draft cooling tower (LMDCT), a coal blending facility, dust collectors and dust suppression equipment, an ash barge loading system, an auxiliary steam boiler, and backup diesel generator.

On February 13, 2007, EON submitted an application for a significant revision to amend the air permit (Permit V-02-043, Revision 2) for permitting design revisions to the TC2 project. The KDAQ accepted the significant revisions and issued a final permit (Revision 3 of this permit) on February 29, 2008. The new unit and associated equipment are currently under construction and are not in operation.

KDEP - KPDES General Permit for Storm Water Discharges from Construction Sites/Best Management Practices Plan

According to the KDEP Issued Permit Online Database, this permit was issued to LG&E on February 11, 2004. Records provided by EON confirm issuance of a KPDES construction storm water permit on July 1, 2006.

Kentucky Department of Housing, Building, and Construction (KDHBC) - Building Code Plan Review

This review will occur once construction has been completed.

Local

Trimble County Department of Health (TCDOH) - Plumbing Approval

This review will occur once construction has been completed.

5.3.2 Permits Required for Operation

The following permits must be obtained prior to commencing operation of Unit 2 or, in the case of the KDEP Title V Permit, within 60 days after startup.

Federal

EPA - Title IV Acid Rain Permit

Refer to discussion in KDEP - State Air Permit to Construct in Subsection 5.2.1.

EPA - SPCC Plan Revision (for Operation of New Unit)

The station has a Best Management Practices and Spill Prevention, Control, and Countermeasures (SPCC) Plan dated October 2007. This SPCC plan responds to EPA oil pollution prevention requirements and serves as a best management practices plan, as required by the KDEP wastewater discharge permit. The plan includes TC2.

State

KDEP - Title V Permit

Refer to discussion in KDEP – State Air Permit to Construct in Subsection 5.2.1.

KDEP - KPDES Individual Wastewater/Storm Water Permit Modification

The station has a KPDES wastewater discharge permit (Permit No. KY0041971) issued by KDEP in 2002. The permit expired on September 30, 2007. EON submitted a renewal application in April 2007 that included anticipated discharges from TC2. A letter from KDEP on April 17, 2007 acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. The station continues to operate under the terms of the 2002 permit until permit renewal is processed by KDEP.

KDHPC - Certificate of Occupancy

This certificate will be obtained once construction has been completed.

Other Permits

In addition to the permits listed above, EON was required to obtain numerous permits or approvals for specific facility components, such as the control room, steam turbine building, boiler building, and the turbine generator. A list identifying these permits and the date on which they were obtained is provided in Table 5.1-1.

Table 5.1-1
Trimble County 2 - Other Permits

Date	Permit	Subject
11/9/06	Conditional Site and Foundation Approval	TC2 Boiler Foundation
2/9/07	Site and Foundation approval Only	TC2 Turbine Pedestal Foundation Bldg.
4/2/07	Site and Foundation approval Only	TC2 Unit Steam Turbine Bldg.
4/4/07	KY Label or KIBS/Conditional Site Approval	TC1 LMDCT E-House Foundation
4/5/07	Superstructure Approval	TC2, Tiers 1 and 2
4/26/07	Site and Foundation	TC 2 Turbine Generator Pedestal Legs and Table Top
10/19/07	Site and Foundation with notes	TC2 DESP Bldg
11/13/07	Superstructure Approval Only	TC2 Unit Steam Turbine Bldg.
12/18/07	Final Inspection	TC1 LMDCT Electrical Bldg.
1/15/08	Superstructure Approval Only	TC Unit 2 Steam Turbine Bldg.
2/12/08	Conditional Approval	TC Unit 2 Control Room
3/17/08	Conditional Approval	TC2 Boiler Bldg.
5/20/08	Conditional Approval for Superstructure Approval (Proceed with Construction)	TC2 Steam Turbine Bldg. TC Unit 2 (Control Room Mods)
7/1/08	Sprinkler System Approval	TC 2 Control Room

5.4 Key Findings

- Black & Veatch review of the EPC Contract and June 2008 Progress Report indicates that the EPC activities have been completed very close to the Contractor's plan. The total approved scope change amount, as of June 2008 when 29.8 percent of the overall project was complete, is only about $1.5 million. The cost of the project has been very close to the budget until now. Although the scope change amount is low, there is potential for more scope change and adjustments during the next aggressive part of the schedule, because of construction labor availability and the labor rate issues. The amount of scope change is not expected to be excessive or abnormal, as the EPC contract has a limit on the labor rate escalation.

- The schedule indicates that over the next 10 months, the Contractor has to achieve a monthly average of 5.4 percent completion. While this may be achieved for an individual month, the likely average rate will be closer to 3 to 3.5 percent. This opinion is also supported by one of the reasons given for the 1 month delay because of labor shortage. The construction progress can cause schedule delay unless closely monitored by the Contractor. However, the EPC contract appears to have sufficient provisions to protect EON from schedule delay. LDs can be assessed if the EPC contractor failed to meet the guaranteed commercial operation dates or other milestones stated in the contract.
- The guaranteed net heat rate of 8,662 Btu/kWh and the auxiliary power of 48.8 MW appear to be quite aggressive for the unit. Even considering the highly efficient supercritical cycle and the use of the natural draft cooling tower, which does not require fan power, these values may not provide much margin. However, this risk lies with the EPC Contractor, because EON is protected by appropriate LDs for the guaranteed heat rate and power output stated in the EPC contract.
- Numerous federal, state, and local permits were or will be required for construction and operation of the project. EON has applied for and received the necessary construction permits. Operating permits cannot be obtained until construction is complete.

6.0 Regulatory and Compliance Summary

Environmental permit status and regulatory compliance were evaluated for each EON facility in Sections 2, 3, and 4 of this report. This section will summarize some of the environmental compliance issues applicable to all of the facilities and will address additional company-wide environmental issues.

6.1 EON Environmental Compliance Summary

Based upon the documents reviewed in this study and the observations during the site visit, Black & Veatch concludes that EON has a proactive environmental compliance program for its generating facilities. Some highlights, based upon the project review, include the following:

- EON maintains a professional environmental staff in its Louisville, Kentucky, headquarters and at the individual facilities; this staff provides a systematic approach to ongoing environmental planning.
- EON has systems in place to submit environmental reports as required, maintain environmental documentation, and plan future environmental needs based on future generation requirements and applicable regulatory requirements for each facility.
- As demonstrated in the 2008 to 2012 Operating Plans available for several facilities, EON has active planning for future environmental needs through maintaining awareness of regulatory developments and incorporating environmental needs into company planning.
- Black & Veatch concludes that the number of compliance issues (exceedances and violations) has been relatively low, considering the number of facilities the company operates and the variety and complexity of these operations.
- From the documents provided, EON actively assesses its environmental compliance by conducting both internal and external reviews and performs compliance audits of environmental programs to assess compliance with permit conditions and to identify options for continued compliance improvement.
- For several facilities, EON has assigned compliance responsibilities for specific permits or programs to individual staff members. Additionally, for many, staff accountability for compliance is part of the company's overall Performance Excellence Process and staff's annual performance

ratings. EON is investigating alternatives to measure accountability for those hourly personnel who do not participate in this program.

- Individual EON generating stations maintain an Environmental Compliance Manual that details the facility's environmental policies, procedures, training, and document control. Each of the manuals summarizes permits, environmental plans, and staff responsibility. Such documents, along with EON's intranet-based Environmental Procedures Manual, provide a systematic definition of each facility's environmental compliance program.

As a result of the aforementioned approach in its environmental programs, EON is demonstrating an active concern with minimizing the potential environmental liabilities associated with its continuing operations.

6.1.1 Environmental Regulatory Issues Associated with the Clean Air Act (CAA)

Recent changes in federal air regulations associated with such pollutants as Hg, acid mist, $PM_{2.5}$, NO_X and SO_2 have lead to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is based on known regulatory programs as well as these changing regulatory issues. Compliance with air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air regulatory programs, no attempt in determining how these changes will affect an individual facility or the power generation fleet will be made. However, EON appears to maintain an active awareness of and responsible planning toward the possible paths of the future regulatory changes. The following provides a general summary of several known CAA regulatory issues with the potential to impact EON.

6.1.1.1 Clean Air Interstate Rule. In July 11, 2008, a unanimous decision by a three-judge panel of the federal District of Columbia (D.C.) Circuit Court of Appeals effectively overturned the CAIR that was set to take effect in 28 eastern states in less than 6 months. The court's decision declared the EPA's proposed NO_X and SO_2 trading program to be "fundamentally flawed" and ordered the agency to make wholesale revisions to the program to comply with the CAA.

This CAIR program was generally supported by many environmental and industry groups, and the states and other petitioners challenging the rule mostly sought to have only certain provisions of the rule revised or set aside. However, the sweeping nature of this decision, which essentially sends the entire rule back to the drawing board, leaves the

EPA, states, and the utility industry facing considerable uncertainty about the future path of this rule.

The following is a summary of points regarding the CAIR decision:

1. The EPA's CAIR that had established a two-phased cap-and-trade program for regulating NO_x and SO_2 emissions from electric utility units in 28 eastern states was vacated by the D.C. Circuit Court of Appeals and is no longer valid or in effect.
2. CAIR sought to reduce or eliminate the impact of upwind utility sources on downwind nonattainment areas for fine particulate matter ($PM_{2.5}$) and 8-hour ozone. States were required to enact and adopt laws and rules to implement the CAIR program through State Implementation Plans (SIPs).
3. The court found that the EPA's approach in establishing a region-wide cap-and-trade program to address downwind $PM_{2.5}$ and ozone nonattainment was not authorized under the CAA.
4. The EPA may now either (1) appeal the decision to the full D.C. Circuit or Supreme Court or (2) revise CAIR through a new rulemaking process that connects each state's emissions reductions to some measure of its own significant contributions to downwind nonattainment areas. Alternatively, Congress could revise the CAA or enact another statute to authorize the EPA's proposed emissions trading approach to regulating NO_x and SO_2 emissions.

Utilities such as EON could defer many SCR and FGD upgrade projects until some regulatory certainty is provided, possibly several years into the future. At this time, EON indicated plans to continue with the current construction program for the FGD projects. Meanwhile, in the eastern United States, many older units may become subject to the Regional Haze Best Available Retrofit Technology requirements, and the NO_x SIP Call program will continue.

6.1.1.2 Clean Air Mercury Rule. In a decision issued February 8, 2008, the federal D.C. Circuit Court of Appeals vacated the CAMR. Finalized by the EPA in 2005, CAMR established a cap-and-trade program set to begin in 2010 to regulate Hg emissions from coal fired utility units (>25 MW) located in all 50 states, and to establish performance standards for Hg emissions from new coal fired units constructed or modified after January 30, 2004. The court found that in adopting this rule, the EPA had unlawfully delisted (removed) electric generating units from regulation under Section 112 of the CAA, which invalidated the underlying basis for EPA to implement CAMR.

The following is a summary of points regarding the CAMR decision:

1. The EPA's CAMR that had established a two-phased cap-and-trade program for regulating Hg emissions from coal fired utility units greater than 25 MW was vacated by the D.C. Circuit Court of Appeals and is no longer valid or in effect.
2. When the rule was finalized in 2005, states were required to enact and adopt laws and rules to implement the CAMR program through SIPs. Although the EPA offered model rules to follow, many states adopted different (often more stringent nontrading) programs in developing its individual SIPs.
3. The EPA must now either (1) appeal the decision, (2) address its procedural errors and omissions in delisting electric generating units as a source category under Section 112 of the CAA cited by the court, and/or (3) develop new regulations that impose strict limits on Hg emissions from power plants under a nontrading program. Given the time required to complete any of these options, resolution will not be achieved until the next presidential administration.
4. Utilities that had developed compliance strategies based on a nationwide Hg trading program are now faced with having to comply with multiple different state requirements enacted in their CAMR SIPs, and uncertainty at the federal level as to how and when the EPA will ultimately regulate Hg emissions.
5. New coal plant permitting must now establish specific Hg emission limits on a case-by-case basis, and coal plants that were permitted in the interim (since March 2005), such as TC2, which established an Hg emissions level lower than the originally prescribed new unit Hg emission limit, may need to have its Hg emission limits reestablished.

6.1.1.3 Best Available Retrofit Technology. Under regional haze regulations, the EPA has issued final guidelines, dated July 6, 2005, for Best Available Retrofit Technology (BART) determinations (70 FR 39104-39172). Sources are BART-eligible if they meet the following three criteria:

- Potential emissions of at least 250 tons per year of a visibility-impairing pollutant.
- Were put in place between August 7, 1962 and August 7, 1977.
- Fall within one of the 26 listed source categories in the guidance.

A BART engineering evaluation using five factors identified in the regulations is required for any BART-eligible source that can be reasonably expected to cause or contribute to impairment of visibility in any of the 156 federal parks and wilderness (Class I) areas protected under the regional haze rule. The evaluation assesses potential air pollution control technologies which can be installed on the existing units to reduce visibility impairing pollutants of NO_x, SO_2) and particulate (both primary and secondary). Also, as established by the EPA, Kentucky's inclusion in the CAIR emissions trading program satisfied the need for evaluation of the pollutants SO_2 and NO_x. In addition, based on a settlement agreement between the EPA and the Utility Sector, NO_x and SO_2 emissions were to be excluded from the BART exemption modeling.

In 2006, LG&E determined that the following 10 units at four facilities were BART eligible units:

- E.W. Brown Station - Units 2 and 3.
- Ghent Station - Units 1 and 2.
- Cane Run Station - Units 5 and 6.
- Mill Creek Station - Units 1 - 4.

Following the BART guidance, and conducting analyses focusing only on particulate matter, LG&E submitted a report in July 2007 to KDAQ which demonstrated that the E.W. Brown Station, Ghent Station, and Cane Run Station BART-eligible units were exempt from BART requirements. However, the Mill Creek Station facility was determined to be BART-applicable and required a full BART engineering and modeling evaluation. Therefore, LG&E conducted an evaluation for primary and secondary particulate (such as SO_3) controls on Mill Creek Units 1-4. LG&E submitted the full Mill Creek Station BART evaluation in September 2007. Based on correspondence with LG&E, KDAQ accepted the BART analyses for the 10 units, placed an SO_3 limit on Mill Creek Station Units 3 and 4, based on sorbent injection technology, and submitted a "final" regional haze SIP to the EPA on June 25, 2008.

As previously noted, on July 11, 2008, the D.C. Circuit Court vacated the CAIR program. This decision by the D.C. Circuit Court will likely cause larger older electric generating units that had been subject to CAIR to lose their exemption from BART requirements of the Regional Haze Program. These units are likely to have to install additional SO_2, NO_x, and particulate emissions controls. Specifically, because the Mill Creek Units were determined to be BART-applicable, these units may be required to conduct engineering analyses for potential SO_2 and NOx emissions controls and reassess the previous determination for particulate control. In addition, because the E.W. Brown Station, Ghent Station, and Cane Run Station facility BART analyses and their resulting exemption from the BART program relied only upon visibility impacts based on particulate, these facilities may be required to reassess their facility specific regional haze visibility impacts based on the additional emissions of SO_2 and NO_X Pending the outcome of the recent CAIR determination and how it affects the previous BART determinations for these facilities, additional controls for SO_2, NO_X, and particulate and potential additional emission limits for units that currently have SO_2 and NO_X controls could result in significant future expenditures for these facilities.

6.1.1.4 Potential for Regulation of Greenhouse Gas. In April of 2007, in the Massachusetts v. EPA decision, the United States Supreme Court ruled that the EPA has authority under the CAA to regulate the emissions of GHGs, such as CO_2, from automobiles. The Court noted the Act's sweeping definition of "air pollutant" and the scientific and political recognition of climate change and its effects and concluded that Congress intended to encompass GHGs in the Act's mandate to regulate any air pollutant that may endanger public welfare.

Legally, the decision itself does not mandate any governmental action beyond further review by the lower appellate court; the scope of this decision is limited to automobile emissions. The EPA could still decide not to regulate CO_2, but only if it also concluded that such emissions do not contribute to climate change or endanger public health and welfare. However, the Supreme Court has now joined the other federal branches in recognizing that the US government needs to do more to address the contribution of GHG emissions to global climate change. Multiple legislative bills have been proposed in Congress that will authorize and mandate the EPA to regulate GHG emissions. It is unlikely that any legislation will be passed prior to the November 2008 election, but it is widely predicted that GHG legislation will eventually be passed within the next few years. Since legislation takes precedence over regulations in US law, and is less vulnerable to legal challenge, it is very likely that a federal legislative (not regulatory) action will drive regulation at a national level.

In the absence of regulation at the federal level, 13 states have already passed their own legislative mandates to regulate GHG emissions at the regional/state/local level. Although Kentucky has not yet passed any legislation to regulate GHG emissions, it could decide to do so. Legislation at either the state or national level has the potential to impact EON by imposing limits on GHG emissions, requiring sequestration of CO_2 emissions, and requiring other methods to address climate change that would result in additional costs to EON to ensure compliance with these regulatory programs.

6.1.2 Clean Water Act Section 316(b) Regulations

Section 316(b) of the Clean Water Act (CWA) requires applicants for a National Pollutant Discharge Elimination System (NPDES) wastewater discharge permit to minimize adverse impacts to aquatic ecosystems from cooling water intake structures. The withdrawal of cooling water has the potential to cause adverse environmental impacts due to impingement and mortality of organisms, primarily fish, on screens that protect the intake system, and through entrainment and mortality of small organisms, primarily fish eggs and larvae, that pass through those screens and through the plant's entire cooling system. Section 316(b) requires that the location, design, construction, and capacity of cooling water intake structures reflect the best available technology (BAT) for minimizing adverse environmental impacts.

EPA published its final NPDES regulations addressing cooling water intake structures for Phase II facilities[1] in April 2004. The Phase II rules gave facilities the option of establishing BAT by demonstrating that (1) existing design and construction technologies meet the specified standards, (2) a combination of existing and new design and construction technologies meet the specified standards, or (3) a site-specific determination of BAT for minimizing adverse environmental impact is appropriate for the site. The location, design, construction, and capacity of cooling water intake structures are considered when evaluating BAT designs. Other critical factors can include the shape of the shoreline, water velocity, size and placement of screens, and the use of biocides, such as chlorine, to control bacterial growth and mollusks such as zebra mussels.

In order to demonstrate BAT design, it is necessary to perform a 316(b) analyses. In general, the following is discussed in a 316 (b) analysis:

1. The engineering and biological data used and assumptions made in the assessment;
2. The biological characteristics of local fish populations;
3. The anticipated effects of the proposed intake design and other reasonable design alternatives on local fish populations; and
4. The general economic considerations for each reasonable alternative.

A conclusion regarding the BAT design for the proposed project is then made based on Items 1 through 4 above. The EPA (or the state permitting agency) will review the BAT analysis when processing the NPDES renewal application, which is conducted every 5 years.

Many facilities were in the process of performing their 316(b) analyses when the EPA suspended the requirements for cooling water intake structures at Phase II existing facilities, pending further rulemaking. The rule was suspended on March 20, 2007, in response to the 2nd Circuit Court of Appeals decision in Riverkeeper, Inc., v. EPA.

EON was in the process of completing impingement studies, biological characterization studies, and/or alternate intake analysis for applicable facilities at the

[1] Phase II facilities are large existing power generation facilities withdrawing more than 50 million gallons per day (mgd) of cooling water.

time of the rule suspension. The reports already completed for the studies will likely be useful in planning compliance with future revisions of Section 316 (b) regulations.

6.1.3 Other Environmental Regulatory Programs

Other historic, current, and future environmental issues impact the power generation industry. This section describes some additional environmental issues not otherwise addressed in this report and how the issues are related to EON.

6.1.3.1 Landfills. Utility combustion byproduct wastes, such as fly ash, bottom ash, slag, and flue gas emission control wastes, are excluded from consideration as hazardous waste in the federal hazardous waste definitions (40 CFR 261.4). Kentucky regulations for special waste (401 KAR 45) direct the requirements for the management of utility byproducts. The EPA has considered developing new federal rules for combustion byproduct wastes in the future, which could include more stringent requirements for managing these wastes. However, Black & Veatch is not aware of any new regulations that are actively being developed by the EPA or the State of Kentucky that would impact the EON facilities at this time.

6.1.3.2 Asbestos. Asbestos was previously used widely in construction and in equipment associated with power generation facilities. EON has active programs in place for asbestos management associated with such activities as equipment maintenance and general construction. An internal EON audit services report, dated March 13, 2008, reviewed by Black & Veatch, demonstrates EON's program to comply with asbestos related regulatory requirements.

6.1.3.3 Polychlorinated Biphenyls. Most power companies have resolved the environmental compliance issues associated with the past widespread usage of polychlorinated biphenyl (PCB) compounds through active replacement programs in the 1980s. EON documents referenced an apparent lack of remaining PCB at the EON facilities because of past replacement and removal activities.

6.1.4 Preexisting Environmental Conditions

This evaluation did not focus on pre-existing environmental conditions such as site contamination. No Phase 1 Environmental Site Assessment Reports were provided to evaluate the prior activities at each site and possible long-term environmental conditions to be considered in site development. Additionally, the evaluation did not specifically include a review of risk management planning, radiation source management, Comprehensive Environmental Response, Compensation and Liability Act (Superfund) – related liabilities, Occupational Safety and Health Administration (OSHA) requirements, US Coast Guard regulations, or Department of Transportation (DOT) requirements. The audit also did not assess the ongoing construction or onsite contractor activities.

7.0 Operating Programs and Procedures

Black & Veatch has examined the O&M plans and processes for the EON generating assets through a review of the respective plant Operations Plans and through discussions with plant management during the site visit process. The facility-specific description and review of these plans and processes are summarized in Sections 2.0, 3.0, and 4.0 of this report. The findings from this review are focused on, and organized around, the following major issues:

- Operations, including training programs and operating procedures.
- Maintenance, including outage management, preventive maintenance, and predictive maintenance programs.

This review addressed the efforts of each of the major generating stations with respect to their current practices and plans for improving or enhancing their current practice. The observations include many consistent practices that have been implemented across the fleet, though the level of development or implementation varied at each plant.

The findings were, for the most part, that each of the stations has attempted to implement improvements in their training programs in order to ensure that the employees at each respective unit have a comprehensive knowledge of the fundamentals of power plant operations. This knowledge is then complemented with training regarding the specific issues for the respective position and plant. Likewise, each plant appears to be implementing some level of improvement in the quality and quantity of operating procedures available for and used by the plant operating staff.

With respect to the maintenance functions, the review focused on understanding each plant's outage management processes, including the level to which they have incorporated the details of the outage management strategy guidelines developed by EON for the generating fleet. Likewise, Black & Veatch reviewed the information available regarding each plant's preventive maintenance programs and their application of predictive technologies and consistency with the Predictive Maintenance Strategy outlined for all the plants.

The findings from this aspect of the review would suggest that the larger, higher value generating units have committed more resources, and as a result, have implemented and documented more of the details associated with the primary maintenance functions. For the most part, the stations have a dedicated outage planner on the staff and are incorporating the guidelines of the outage management strategy into routine practice. All indications are that each of the plants has implemented a standardized maintenance planning process and utilize the Maximo CMMS application to track and document work processes. Each of the plants is working to incorporate a condition-based maintenance strategy when and where it is applicable. All the plants noted specific PDM processes that have been incorporated into the plant maintenance practices.

Overall, the plants appear to either be utilizing or implementing what are considered to be "industry best practices" including all of the following:

- Standardized operating procedures.
- Training programs that include basic skills supplemented with unit-specific training.
- Utilization of a CMMS for tracking and documenting work management.
- Planning processes designed to enhance outage management and execution.

8.0 Contracts and Agreements

8.1 Contract Overview

The following sections provide a brief overview of the LG&E and/or KU (both LG&E and KU are subsidiaries of EON) contracts and other publicly available documents Black & Veatch has reviewed to assess the following subject matters:

- Fuel supply and transportation.
- Reagent supply and transportation.
- Transmission and interconnection.
- Power purchase and interchange.

8.2 Fuel Supply and Transportation

8.2.1 Coal Supply and Transportation Contracts

EON has provided 19 coal supply and transportation contracts from various suppliers and mines. A detailed summary of each contract (with key terms such as contract duration, termination, renewal, quantities, pricing, delivery points, etc) can be found in Appendix C.

The base quantity of coal supply typically changes from year to year in each contract. The coal supply contract with Armstrong Coal has the longest term, which will expire at the end of 2015. The rest of the coal supply contracts will expire before the end of 2011. These contracts will either be renegotiated for extension beyond their current terms or allowed to expire while alternative sources are contracted.

Most of the coal supply contracts include firm base prices that extend through the entire terms of the contracts. Each coal supply contract includes coal specifications required to meet the coal firing requirements of various coal fired generating units owned by EON. All contracts have coal quality provisions that generally allow for adjustments to base prices if the heat content, ash, moisture, and sulfur levels in the coal delivered deviate from the guaranteed levels. Overall, the coal supply contracts have guaranteed heat contents ranging from 10,400 Btu/lb to 12,500 Btu/lb.

Coal can be transported via barge, rail, and/or truck to various coal fired generating stations owned by EON. In addition to the coal transportation provisions that are included in a few of the coal supply contracts, EON currently has three transportation contracts (rail and barge) that cover different loading and delivery points. The detailed summaries of these contracts are included in Appendix D.

The counter parties, expiration dates, and applicable maximum base coal supply quantity for 2008 of the coal supply and transportation contracts are shown in Table 8.2-1.

Table 8.2-1
EON Coal Supply and Transportation Contracts

Contract Counter Parties	Expiration Date	2008 Coal (tons)
KU and The American Coal Company	June 30, 2008	240,000
KU and Covenant Coal	May 31, 2009	120,000
KU and Little Elk Mining	June 30, 2009	800,000
LG&E, KU, and COALSALES Purchase Order	December 31, 2009	100,000
LG&E, KU, and Southern Appalachian Coal	December 31, 2009	180,000
LG&E, KU, and Phoenix Coal/Charolais Coal	December 31, 2009	300,000
KU and Alpha Coal Sales	December 31, 2009	324,000
LG&E, KU, and Smoky Mountain Coal	December 31, 2009	950,000
LG&E, KU, and Patriot Coal	December 31, 2009	1,250,000
LG&E, KU, and COALSALES Agreement	December 31, 2009	1,400,000
KU and ICG	December 31, 2010	400,000
LG&E, KU, & Charolais	December 31, 2010	700,000
KU and Nally and Hamilton Enterprises	December 31, 2011	150,000
KU and Perry County Coal	December 31, 2011	120,000
LG&E and Alliance Coal	December 31, 2011	4,250,000
LG&E, KU, and Armstrong Coal	December 31, 2015	600,000
LG&E, KU, and Crouse Corporation	December 31, 2013	Barge Only
LG&E and Paducah & Louisville Railway	December 31, 2011	Rail Only
KU and CSXT/TTI Railroad	December 31, 2010	Rail Only
Total Coal to be Supplied Under Contract for 2008:		11,884,000

8.2.2 Natural Gas Supply and Transportation Contracts

EON has provided two natural gas supply and transportation contracts for review by Black & Veatch. Detailed summaries of these contracts can be found in Appendix E

The first contract is an intercompany firm gas sales and transportation service contract between the gas distribution business of LG&E and electric generation businesses of LG&E and KU. The agreement is automatically renewed annually unless terminated by either party. The firm natural gas supply quantity of this contract only covers a portion of the requirement from the natural gas fired peaking generation units owned by LG&E and KU. The electric generation businesses of LG&E and KU have to purchase the remaining gas supply requirement from third parties to be delivered to designated points at the LG&E gas distribution network for firm transportation through

LG&E gas distribution facilities to the electric generation facilities owned by LG&E and KU. The maximum daily quantities for natural gas transportation should allow for full operation of all natural gas fired peaking units owned by LG&E and KU.

The second contract is a firm natural gas transportation contract between KU and Texas Gas Transmission, LLC (Texas Gas) which covers delivery of natural gas from Texas Gas' Centerpoint-Bosco, Regency-Riverton, or Pan Energy-Perryville locations to the KU Bedford No. 2 delivery point in Trimble County, Kentucky. The primary term of this agreement will expire in October 31, 2012. The agreement will be automatically renewed unless terminated by either party. The base contracted daily quantities for summer and non-summer months appear to be sufficient to meet the dispatch needs of the peaking units owned by LG&E and KU. Additionally, should the need arise, there is provision for KU to receive more natural gas from Texas Gas by paying an overrun transportation rate.

8.2.3 EON Fuel Supply and Transportation Strategy and Policy

In addition to the fuel supply and transportation agreements, EON also provided the following documents for Black & Veatch review:

- Fuel Procurement Policies and Procedures.
- Statement of Trading.
- Corporate Fuels Department's Demand Analysis Guideline.
- Corporate Fuels Department's Contract Management Guideline.
- Corporate Fuels Department's Receipt of Goods Guideline.
- Corporate Fuels Department's Stocktaking Guideline.

The following provides a general overview of the EON fuel supply and transportation strategy and policy based on Black & Veatch review of the above information:

- EON has an enterprise-wide process to obtain an adequate and reliable supply of sufficient quality fuel at the lowest cost consistent with its obligation to provide adequate and reliable service to its customers. The company endeavors to secure fuel supply at competitive prices through the use of the formal procurement process, informal bid, and negotiation process. The award of all contracts and purchase orders are to be in compliance with EON internal business controls. Such internal controls include its minimum authority limit matrices (which outlines the maximum terms and amounts each EON personnel is authorized to approve based on their positions), Sarbanes Oxley compliance, and internal auditing recommendations.

- EON has a dedicated corporate fuels department that is responsible for procurement of coal, solid fuel, fuel oil, scrubber reagent, propane, ammonia, other bulk commodities, and transportation services by ship, barge, rail, truck, or other means for use by its generation assets. The main responsibilities of this department are to negotiate short- and long-term contracts for deliveries of coal and related commodities and services; ensure that the fuels portfolio is appropriately hedged at all times; perform overall management of the fuels portfolio; identify potential market opportunities; advise and consult with the other department personnel on appropriate strategy, hedging techniques, and appropriate trading activities, given the current fuels market conditions and the EON stated trading objectives; and ensure that all transactions are correctly entered into an appropriate tracking system daily and balanced to its fuel supply management system weekly.
- All material factors are considered to ensure fuel will be purchased at competitive prices. These factors include quantity needed to maintain an adequate inventory, quality required to meet operating characteristics and environmental standards, resulting bus bar energy costs, reliability and diversity of suppliers, fuel transportation modes, and meeting emergency or other unusual circumstances affecting market conditions.
- EON has internal procedures in place to frequently analyze fuel supply projections (for current, short, and long terms), contract versus spot mix, and perform supplier qualifications.
- Most of EON informal bidding processes through telephone, electronic mail, or facsimile are typically used for spot purchases.
- EON procures fuel oil only on an ''as-needed'' basis without any short- or long-term contracts, because of the infrequency of use and the nature of the oil market. EON uses Fuelworx as its fuel supply management system.
- The EON goal for physical coal inventories is no lower than 15 days of average burn and no greater than 80 days of average burn. The goal for alternative fuel physical inventories is no lower than 15 days of average burn and no greater than 150 days of average burn. The inventories are monitored on a weekly basis and accounted for on a monthly basis, to ensure compliance.
- Generating station personnel have primary responsibility for maintaining and reporting physical inventory of coal, petcoke, and limestone at each

facility. EON has an internal stocktaking objective to ensure that the employees who undertake controls and counts of physical inventory are not also employed in the company's materials management operation. The segregation of such functions is intended to detect and prevent fraud.

8.2.4 Fuel Supply and Transportation Key Findings

Based on the review of the information discussed in Subsections 8.2.1 through 8.2.3, Black & Veatch has formed the following opinions:

- EON appears to have a sound fuel supply and transportation strategy/policy in place to ensure adequate and reliable supply of low-cost fuel.
- The EON coal supply and transportation contracts appear to have adequate coverage to ensure diversities (supplies from different vendors and mine locations) in coal supplies and transportation modes (deliveries via barge, rail, and/or truck). In addition, it is Black & Veatch's understanding that EON typically maintains, on average, more than 45 days of coal inventory on hand. These should avoid possible supply interruptions due to unforeseen events.
- The coal supply contracts appear to have sufficient provisions for the continued supply of quality coals, subject to the various coal specifications included in the contracts.
- Most of the terms included in the coal supply contracts are between 1 to 5 years. They also include provisions for adjustments to the firm base prices or rejection by buyers if the quality of the delivered coal does not meet the minimum guaranteed levels. These terms and conditions are considered typical in the industry.
- The quantity of coal purchased under contract by EON appears to be sufficient to cover approximately 75 percent or higher of the coal required for baseload operation of its coal fired power plants. EON makes spot market purchases to meet the remaining coal requirements on an as needed basis. It is Black & Veatch's understanding that EON strategy is to maintain a certain ratio of coal supply purchased under contract versus spot market purchases to meet its hedging goals, subject to market conditions. Most of EON existing coal contracts are of "take or pay" type, and EON appears to have strong buying power (because of its coal fired fleet) in the spot market. Black & Veatch is of the opinion that the current contract versus spot mix of EON coal supply appears to be reasonable and

should facilitate possible opportunistic purchase of low-cost coal supplies from the spot market or distressed coal assets.

- EON appears to have sufficient natural gas transportation services under contract to meet the dispatch requirements of its natural gas fired peaking units in the summer and non-summer months. In addition, the EON firm natural gas transportation contract with Texas Gas covers potential delivery of natural gas from three possible points of origin on the Texas Gas system to an EON-designated delivery point. These arrangements should allow EON the flexibility to purchase natural gas from various suppliers who can deliver gas to any of the three possible points of origin.

8.3 Reagent Supply and Transportation

8.3.1 Reagent Supply and Transportation Contracts

EON has provided three reagent supply and transportation contracts from various suppliers. A detailed summary of each contract (with key terms such as contract duration, termination, renewal, quantities, pricing, delivery points, etc) can be found in Appendix F.

The Cane Run Generating Station receives crushed lime from the Chemical Lime Company of Missouri and the E.W. Brown station receives limestone from Mercer Stone. The remaining limestone for all other plants is purchased from Mulzer Crusher Stone, Inc. Additionally, trona is purchased for Trimble County and Ghent Stations. All contracts have extension provisions, except the Chemical Lime Company Agreement.

The reagent supply contracts include base prices that increase through the contract term. Each reagent supply contract includes specifications required to meet each of the plant's specific bulk material handling requirements. All contracts have quality provisions for reagent size and/or purity. The quantity of reagent purchased varies per contract and is typically bounded on the high and low ends.

The reagents can be transported via barge, rail, and/or truck to the various coal fired generating stations owned by EON. The Mulzer Crushed Stone, Inc. contract provides transportation of the limestone to one of two barge unloading stations. All the other contracts provide transportation directly to their respective plant(s). The most common form of transportation is truck, and each long-term contract has a provision that increases delivered product cost with increases in diesel price.

8.3.2 Reagent Supply and Transportation Key Findings

Based on the review of the information discussed in Subsection 8.3.1, Black & Veatch has formed the following opinions:

- EON has a reagent supply and transportation strategy/policy in place to ensure adequate and reliably supply of lime, limestone, and trona.
- EON reagent supply and transportation contracts appear to have adequate coverage to ensure diversity of suppliers and transportation modes (deliveries via barge, rail, and/or truck).
- Most of the terms included in the reagent supply contracts are between 1 to 10 years. They also include provisions for adjustments to the firm base prices or rejection by buyers if the quality of the delivered reagent does not meet the minimum guaranteed levels. These terms and conditions are considered typical in the industry.

8.4 Transmission and Interconnection

8.4.1 Transmission and Interconnection Contracts

EON has provided six transmission interconnection contracts for review by Black & Veatch. A detailed summary of each contract (with key terms such as contract duration, termination, renewal, pricing, points of interconnections, etc) can be found in Appendix E.

The EON transmission system, which includes transmission systems owned by LG&E and KU, is located on the southeastern edge of the Midwest ISO regional footprint and is bordered by Tennessee Valley Authority (TVA) to the south, the PJM Interconnection to the east, and Big Rivers Electric Corporation to the west. The transmission system is directly interconnected with the transmission systems owned by following entities:

- American Electric Power Service Corporation (member of PJM).
- Duke Energy Shared Services, Inc. (member of Midwest ISO).
- Southern Indiana Gas and Electric Company (member of Midwest ISO), which is a subsidiary of Vectren Corporation.
- East Kentucky Power Cooperative, Inc.
- Big Rivers Electric Corporation.
- Ohio Valley Electric Corporation.
- TVA.

EON has existing transmission interconnection and/or interchange agreements for interconnection of its system with the transmission systems owned by the above entities. These agreements allow for interconnections at 69 kV, 138 kV, 161 kV, and 345 kV levels at various points of interconnection with EON neighboring transmission systems. In general, all of the existing transmission interconnection agreements are of "evergreen" type, which include provisions for initial terms of certain number of years and automatic renewals beyond the initial terms. The agreements can be terminated upon mutual agreements by all counter parties, or with a written notice by the initiating party, subject to approval or acceptance by the FERC.

The intent of the agreements is to define the governing terms and conditions for wire-to-wire interconnections between the transmission systems of EON and neighboring transmission system owners. In general, all parties to the agreements are to operate and maintain their own transmission system in a manner that is consistent with good utility practice, to minimize electrical disturbances and interruptions and to ensure continuous synchronous operations of the transmission systems. All transmission system owners are responsible for operating, maintaining, and testing their own systems and interconnection facilities at the points of interconnections at their sole expense.

8.4.2 Reliability Coordinator and Independent System Operator Contracts

EON has provided three contracts related to reliability coordination and independent system operation for review by Black & Veatch. A detailed summary of each contract (with key terms such as contract duration, termination, renewal, quantities, pricing, delivery points, etc) can be found in Appendix E.

These contracts generally cover the scope of reliability coordination and independent system operation services and functions between EON and the following parties:

- Southwest Power Pool, Inc (SPP).
- TVA.
- Midwest ISO.
- PJM Interconnection.

EON has delegated certain tasks to a FERC-approved independent transmission organization (in this case, SPP) and reliability coordinator (in this case TVA) to ensure that the EON transmission system is operated in an open, nondiscriminatory, and reliable manner.

The independent transmission organization agreement with SPP is effective, based on the effective date of June 1, 2006, for an initial term of 4 years, after which each successive term will be for 1 year. Under this agreement, SPP is responsible for processing and evaluating transmission service requests, performing system impact studies, granting or denying various interconnection/service requests, evaluating and implementing electronic tags, and overseeing the generator interconnection process and expansion planning function. SPP is also responsible for providing independent, non-discriminatory, open access transmission service on the EON transmission system. In addition, SPP is also required to assess and report on instances of possible transmission hoarding on the EON transmission system. EON will still maintain ownership of its transmission system and is ultimately responsible for providing adequate transmission service to its customers, with SPP performing key transmission-related functions set forth in the EON open access transmission tariff and this agreement.

The reliability coordination agreement with TVA was signed on July 19, 2006 for an initial term of 4 years, after which it will be automatically renewed annually. TVA's primary responsibility is to ensure the reliability of the bulk transmission system. TVA's responsibilities under this agreement include reliability analysis, loading relief procedures, ordering curtailment of generation and/or load, monitoring balancing authority area performance, and coordinating with neighboring reliability coordinators and other operating entities, as appropriate, to ensure reliability of the regional transmission system as a whole.

The joint reliability coordination agreement with TVA, Midwest ISO, and PJM Interconnection is dated April 22, 2005 for an initial term of 10 years. The agreement will be automatically renewed on a year-to-year basis. Under this agreement, TVA acts as the reliability coordinator for the EON transmission system. The purpose of this agreement is to allow information exchange between and among the parties, and to establish congestion management protocols for common transmission system flow gates among the parties.

8.4.3 OASIS Transmission and Interconnection Information

In addition to reviewing the transmission agreements provided by EON, Black & Veatch also reviewed certain information posted by EON at the SPP open access same-time information system (OASIS) website, as deemed pertinent by Black & Veatch for the purpose of this due diligence report. The following provides a general overview of the transmission/interconnection information:

- The primary purpose of the EON transmission system is to reliably transmit electrical energy from its designated network resources to its network loads. Interconnections to other transmission systems have been established to increase the reliability of EON transmission system and to provide access to emergency generating sources for EON network customers.
- EON subscribes to and designs its transmission system to conform to the fundamental characteristics of a reliable, interconnected bulk electric

system recommended by the NERC. Additionally, EON is a member of the SERC and subscribes to and designs its transmission system to comply with the reliability principles and responsibilities set forth by the SERC.

- The FERC requires that all public utilities that own, control, or operate facilities used for transmitting electric energy in interstate commerce to have a nondiscriminatory open access transmission tariff (OATT). EON operating companies, both LG&E and KU, have an OATT on file with FERC to provide point-to-point transmission service and network integration transmission service. EON endeavors to provide the same reliability and priority of service to its long-term firm point-to-point transmission service customers (with a contract period of 5 or more years) as it does for its network customers.
- EON incorporates the American National Standards Institute (ANSI) and the Institute of Electrical and Electronic Engineers, Inc (IEEE) standards in the design and application of equipment utilized in its transmission system.
- All of the generating units fully or partly owned by EON are listed as designated network resources on the EON transmission system. In addition, the power purchases from Dynegy, the Ohio Valley Electric Corporation (OVEC), and Owensboro Municipal Utilities (OMU) (the City of Owensboro, Kentucky and the City Utility Commission) are also considered designated network resources on the EON transmission system.

8.4.4 Transmission and Interconnection Key Findings

Based on the review of the information discussed in Subsections 8.4.1 through 8.4.3, Black & Veatch has formed the following opinions:

- The existing wire-to-wire interconnection agreements that EON has in place with neighboring transmission system owners appear to have sufficient provisions to ensure continued reliable and synchronous operations of the interconnection transmission systems and to provide access to emergency generating sources for EON network customers.
- EON Transmission Planning Guidelines include system performance criteria that either meet or exceed the requirements of NERC and SERC reliability standards.
- The designated network resource capacities (listed at EON SPP OASIS) of the generating units fully or partly owned by EON appear to reflect the

full load outputs of each of the generating units. This means that EON should have done the necessary studies and constructed network upgrades needed to integrate its own generating units to serve its native load customers. Therefore, the full load outputs from these generating units should be considered deliverable to EON network customers under normal and N-1 contingency system conditions.

- Even though EON has withdrawn its transmission owning membership from Midwest ISO, EON is still considered an external market participant to Midwest ISO. Such non-member designation can still allow EON to sell to or purchase energy from a Midwest ISO member by paying certain Midwest ISO charges.
- Given that TVA acts as the reliability coordinator for EON under the Reliability Coordination Agreement, and that TVA is a signatory to the Joint Reliability Coordination Agreement (JRCA) with Midwest ISO and PJM Interconnection, the congestion management protocols for common flow gates among the parties to the JRCA also include the EON transmission system. The information exchange provisions under both of these agreements provide for timely calculation of available transfer capability on the EON transmission system to facilitate day-to-day reliable operation of the EON system.
- Overall, EON appears to have proper the agreements, planning and study guidelines, points of interconnections, transmission and interconnection facilities, and operation and maintenance procedures in place to ensure continued reliable and synchronous operations of the interconnection transmission systems, to provide access to emergency generating sources for EON network customers and have a nondiscriminatory open access transmission tariff to serve its network customers.

8.5 Power Purchase and Interchange

8.5.1 Power Purchase and Interchange Contracts

EON has provided three power purchase and interchange contracts for review by Black & Veatch. A detailed summary of each contract (with key terms such as contract duration, termination, renewal, quantities, pricing, delivery points, etc) can be found in Appendix 4.3.4.

The first contract is with the OVEC and had an initial effective date in 1953. The current agreement with OVEC is dated March 13, 2006 and will remain in effect until 2026, unless the facilities are sold or cease to operate. OVEC is jointly owned by

12 companies; KU and LG&E own 2.5 percent and 5.63 percent, respectively, of OVEC. OVEC owns and operates the coal fired Kyger Creek and Clifty Creek Generating Stations with total capacity of approximately 2,200 MW. Each company is required to purchase power (55 MW for KU and 124 MW for LG&E) from OVEC, and may purchase energy. The companies are also required to make spinning reserves available to OVEC in proportion to their portion of ownership in OVEC. The costs for power, energy, and transmission are shared proportionally among the companies.

The second contract is with OMU dates from 1960, and could last through 2019. OMU owns and operates the 400 MW coal fired Elmer Smith Generating Station and sells excess capacity and energy to KU. OMU can terminate the contract with 4 years' notice to KU. KU can terminate with 4 years' notice to OMU if the OMU capacity plus reserves exceeds 320 MW. KU provides backup power to OMU during outages of the Smith Station up to a maximum of approximately 333 MW. KU energy from the Smith Station is limited to 62 percent of the station output. During 2005, KU capacity from the Smith Station averaged 42 percent of the station capacity. The costs for power and energy are shared proportionally between OMU and KU. It is Black & Veatch's understanding that OMU recently gave notice to EON to terminate the contract effective May 2010.

The third contract is between Dynegy Power Marketing, KU, and LG&E and is dated January 28, 2008. The agreement is for the sale of energy and capacity from Unit 1 of the Bluegrass Generating Facility, an approximately 165 MW gas fueled, simple cycle CT unit, from June through September of 2008 and 2009. Unit 1 is designated as a network resource of KU and LG&E during the two summer periods. Dynegy provides fuel for energy at its cost. KU and LG&E may furnish the fuel at their option. The unit can only be dispatched at 0 or 165 MW. Output at 165 MW is limited to 1,500 hours per summer period.

8.5.2 Power Purchase and Interchange Key Findings

Based on the review of the information discussed in Subsection 8.5.1, Black & Veatch has formed the following opinions:

- The electric generating plants owned by EON produce most of the electricity required to serve its native load. The remaining electricity requirement is supplemented by electricity from other suppliers. In 2007, EON produced approximately 33,800 GWh of electricity (or 91.4 percent of total 2007 electricity) from its own generation. EON purchased the remaining 2,900 GWh of electricity (or 8.6 percent of total 2007 electricity) from other suppliers. The majority of the electricity purchased was supplied under the power purchase agreements with OVEC, OMU, and Dynegy.

- LG&E and KU, both subsidiaries of EON, have intercompany agreements to purchase energy from each other in order to effectively manage the load of their retail and off-system customers.
- Under the OMU and OVEC contracts, the capacity and energy purchases made should result in costs that are comparable to the cost of other power purchased or generated by EON.
- Under the Dynegy contract, the provisions should allow EON to meet the peak demand on its system during the summer months, with generation from Dynegy's simple cycle CT peaking unit.
- The designated network resource capacities (listed at EON SPP OASIS) of the power purchases from Dynegy, OVEC, and OMU appear to reflect the maximum available capacities provided under the power purchase contracts with Dynegy, OVEC, and OMU. Therefore, EON should be able to deliver all the purchased energy to its network customers under normal and N-1 contingency system conditions.
- The terms and conditions of the power purchase agreements with OVEC, OMU, and Dynegy appear to have reasonable provisions for EON to obtain baseload, excess, and peaking capacity and energy from the respective counterparties of the agreements.

9.0 Projected Performance and Operating Costs

9.1 Projected Performance

9.1.1 Introduction

Black & Veatch has reviewed the projected performance for each of the generating stations. The unit level projected performance data for each station is included in Appendix A.1. This review included actual historical performance for 2004 through 2007, comparison to applicable industry average performance data from GADS and EON-projected performance for each generating unit. The objective of the review was to evaluate whether the projected performance appears reasonable.

9.1.2 General Observations

Overall, the projected performance for the stations appears reasonable. The projected performance is consistent with the planned EON O&M and capital expenditures for each station, based on condition assessment and specific needs at each site. EON has identified in-depth capital projects for the plants through 2012, to meet the projected performance and reliability of the plants. Black & Veatch review indicated that the projected performance is justified based on past repair/replacements, maintenance, inspection, and testing records, as well as applicable industry averages.

9.1.3 Station Level Observations

The information that follows provides select station level observations based on Black & Veatch review of the pertinent documentation:

- Trimble County Unit 1 - The projected heat rates for TC1 slightly degrades, partially because the transfer from the natural draft cooling tower to the mechanical draft cooling tower adds approximately 40 Btu/kWh of auxiliary load. EON deliberately placed the larger Unit 2 on the existing natural draft tower and the smaller Unit 1 on the mechanical draft tower to have better overall benefit in heat rate. The planned turbine work in 2009 is not expected to have much of an impact on the heat rate. The TC1 EFOR levels have been low, in the 0.5 to 4.0 percent range, but the EFOR targets will require completion of the water wall slope tube and ID fan VFD replacements. Although there have been two recent outages to repair condenser tube leaks, the condenser tube plug percentage reportedly remains low, at less than 1 percent. Plant management has had to perform several outages to correct boiler water conditions.

- Cane Run (Coal) – The station reported that as of July 2008, there were no load limits preventing it from achieving the declared net capacity. A major fire at the Unit 6 boiler burner corner during 2007 is partially responsible for the high EFOR level reported. Boiler tube leaks are the major EFOR driver on all three Cane Run Station units. According to the Operating Plan, a concerted effort has been made to reduce forced outages caused by boiler tube leaks. The projected EFOR targets are reasonable when the planned boiler component replacements are taken into account.
- Green River - Other than a major GR4 outage in 2006 to repair turbine damage caused by operator error, the recent major Green River EFOR drivers have primarily consisted of boiler tube leaks on both units and feedwater heater tubes leaks on GR4. The projected EFOR targets appear to be reasonable.
- Trimble County (CT) - The historic operating heat rates at Trimble County CTs have averaged approximately 11,500 Btu/kWh for the last year. The degraded simple cycle heat rate full load heat rate of a GE PG7241FA+e is expected to be approximately 10,000 Btu/kWh in summer. The station personnel reported that the units are not always historically dispatched at full load. In recognition that the CT units may not always dispatch at full load, the forward projections for heat rate in the planning period are considered aggressive (low). Consideration should be given to updating these to reflect the expected dispatch level and historical operating heat rates.
- Paddy's Run (CT) - Units 11 and 12 are operated infrequently because of their age of more than 40 years and high operating heat rates over 15,000 Btu/kWh. The average capacity factor has been less than 1 percent over the last 5 years and is forecast for a similar low dispatch level through the planning period from 2008 to 2012.

9.2 Projected O&M Costs

9.2.1 Nonfuel O&M Costs

Coal Fired Generating Plants

Black & Veatch has reviewed the nonfuel O&M costs for each of the generating stations. This review included historical values, generally looking back to 2002, and forecast expenditures through 2012. Conventional practice for this type of review includes a comparison of costs in actual dollars, as well as the cost expressed on a per unit of output basis ($/MWh). The objective of this review was to evaluate whether the costs appear reasonable and adequate to address the long-terms needs of the fleet and the respective units.

The figures herein show the comparison information for the coal units expressed (as noted) in total dollars and separately in cost per unit of output. Figure 9.2-1 depicts the total nonfuel O&M costs for all of the EON coal fired units from 2003 through 2007, with projections for the 2008 through 2012 period. All of these figures and the discussion that follows refer to nonfuel O&M costs, even though the abbreviation will simply read O&M. In all cases, however, the term O&M will refer to operations and maintenance costs, exclusive of fuel costs.

General Fleet Observations

Overall, the O&M costs reported and predicted appear reasonable, given the site-specific issues that must be addressed at each station and unit and the expected increases in maintenance costs for generating units as they age. The line item costs for all of the plants reflect the historical and expected increases in compliance costs. As a result, it can be observed that the "Other Cost of Services" line item (refer to the O&M expenses table for the respective station) will have nearly doubled between 2004 and 2012 for each of the units. With the age of the fleet and the requisite maintenance to ensure continued reliability, it can also be observed that the costs for routine and, more importantly, outage maintenance, increase substantially. This is the result of increases in contractor costs, and especially, commodity prices. Some of these costs have already been experienced, as is evident by the increases seen in the 2004 to 2007 historical data. However, this trend is expected to increase and, as a result, the base O&M expenses are expected to increase substantially between now and 2012.

Station-Specific Discussion

The total cost figures highlight the expectation of increasing costs for most of the EON units. These increases are a function of a number of different influences that vary somewhat depending on the specific station but, more importantly, reflect the over-arching issues affecting all of the units. The following discussions focus on the costs for the stations noted as significantly increasing over the time frame of the graph (2005 to 2012):

- Ghent - The significant increases in O&M costs shown on Figure 9.2-1 primarily reflect an expected increase in the line item "Other Costs of Services" (refer to Ghent O&M expenses table). This captures the planned

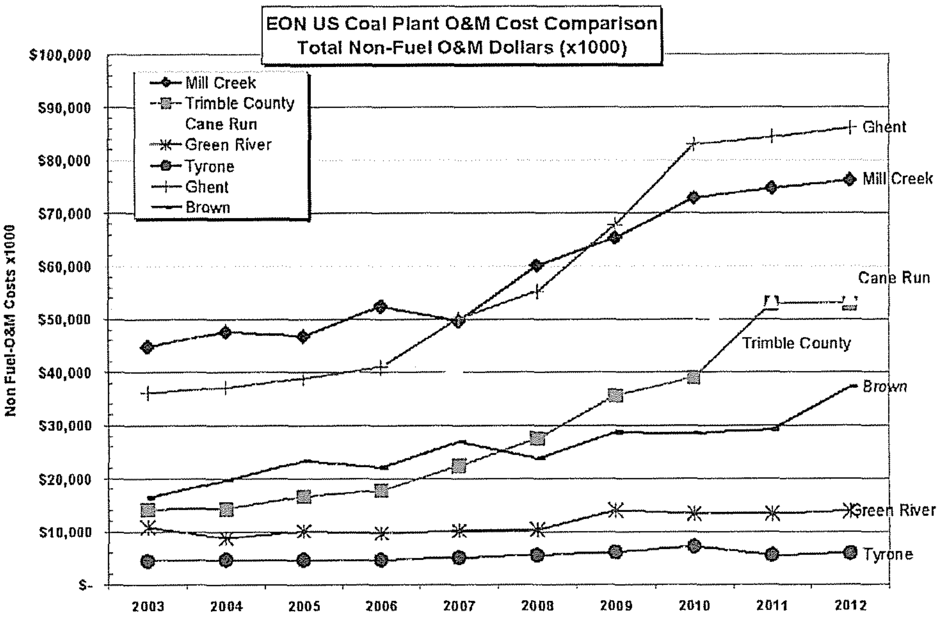

Figure 9.2-1
US Coal Plant O&M Cost Comparison (Total)

addition of scrubbers to Units 2 and 4 and the addition of the SCR to Unit 2. In addition to the added costs for this new equipment, the SCR systems on Units 1, 3, and 4 will be operated 12 months per year, as opposed to the seasonal operation that had been the case in the past. This will result in significant cost increases for ammonia reagent. Comparing these costs on a dollar per unit of output (MWh) basis (refer to Figure 9.2-2) helps put these costs into perspective. In comparison to the other EON units, the costs at Ghent are still very consistent with the other units, especially when compared with those units that tend to be baseload resources versus the lower capacity factor units that provide energy and load regulation.

- Mill Creek - The total cost table for Mill Creek station reflects the issues of planned outages in the 2010 to 2012 time frame that will require significant investment in maintenance repairs for the steam turbines (scrubber systems in particular). Over the same time period, the plant expects to see significant increases in operating costs. As examples, the cost for ammonia in the SCR units is forecast to cost more than $3.7 million in 2011, as opposed to approximately $500,000 in 2005.

Likewise, limestone reagent expenses, which were $2.8 million in 2005, are forecast at $4.3 million in 2011. Overall, the cost increases experienced to date and expected/forecast through 2012 appear reasonable.

- Cane Run - The costs for the Cane Run units (on a total dollar basis) are also showing a trend to significant increases when comparing historical to forecast costs. A primary driver in the short-term for these increasing costs is the major outage work planned for the 2009 to 2010 time frame. These outages address issues at all three units (refer to the discussion of the Cane Run asset for details). The Cane Run units have also seen a significant increase in the "Other Costs of services" line item (during the 2003 to 2012 time frame). This increase is primarily the result of significant increases in the cost of lime for the FGD systems.

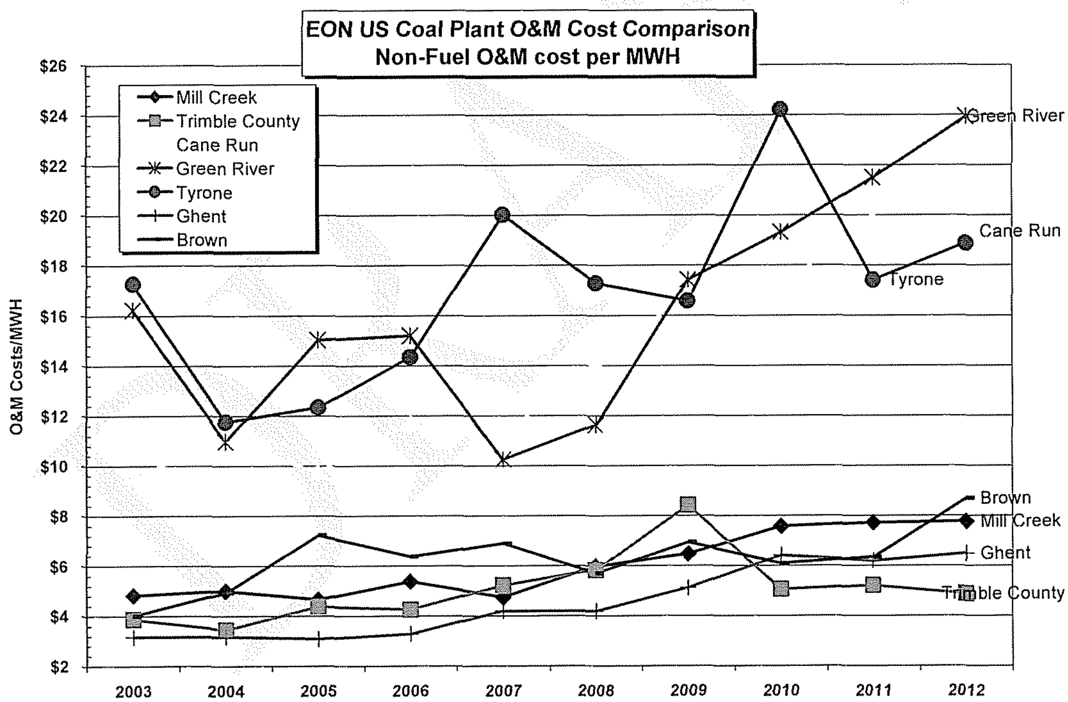

Figure 9.2-2
US Coal Plant O&M Cost Comparison (per MWh)

- Trimble County - The values shown in the total dollar cost basis graphic are somewhat misleading in the sense that these costs show expected O&M costs for Unit 2, which is currently under construction. On a cost per unit of output basis, there is only a modest increase in O&M costs expected between now and the 2012 time frame, which suggests that O&M costs at the unit are under control and reasonable.

- Brown - Though not as pronounced as the previously mentioned units, the total O&M dollars graph would also suggest that the costs at the Brown station have also been increasing at a substantial rate. Costs in 2003 were approximately $45 million and are expected to reach $60 million in 2008. One of the more significant drivers of these cost increases is the O&M costs associated with the new FGD system, expected to be functional in 2009. There are also reasonably large outages planned for each of the three units over the 2009 to 2012 time frame. As a result, of all of these influences, these costs appear consistent with the expectations for normal maintenance associated with units of this age/vintage.

Costs per Unit of Output Discussion

Figure 9.2-1 provides a representation of the station O&M costs on a total dollar basis. It is also helpful to examine these costs on the basis of the cost per unit of energy output. Figure 9.2-2 provides such a comparison.

A review of this data shows that there are two distinct patterns, or groups, of units that are evident. These groups are a reflection of the differences between units that are primarily baseload energy units versus those that provide more ancillary services, such as load regulation. As a result of the differing utilization, the calculation of O&M cost per MWh is influenced by the baseload unit costs being divided into a larger and more consistent volume of energy. In contrast, the energy output from units that provide more ancillary services tends to be less consistent (year to year) and lower. This results in costs per unit of energy that are higher and that tend to fluctuate.

Combustion Turbine Generating Plants

Figures 9-3 and 9-4 show the comparison information for the CT units expressed (as noted) in total dollars and separately in cost per unit of output. Figure 9.2-3 depicts the total nonfuel O&M costs for the primary groups on non-coal generating units from 2004 through 2007, with projections for the 2008 through 2012 period. All of these figures and the discussion that follows refer to nonfuel O&M costs. In all cases, however, the term O&M refers to O&M costs exclusive of fuel costs.

General Fleet Observations

Comparisons of representative costs for nonfuel O&M costs experienced at facilities that are primarily utilizing simple cycle CT technology are difficult to compare due to the fact that the use of the premium priced fuel generally results in the units operating at a very low capacity factor. As a result, comparative data would suggest that prices fluctuate substantially. At the extremes are two scenarios. In the first, a group of units that do not have any major maintenance activities scheduled in a year of high demand will result in a very low calculated cost per unit of output. Conversely, a period of a major maintenance activity coincident with a cool summer and little or no generation

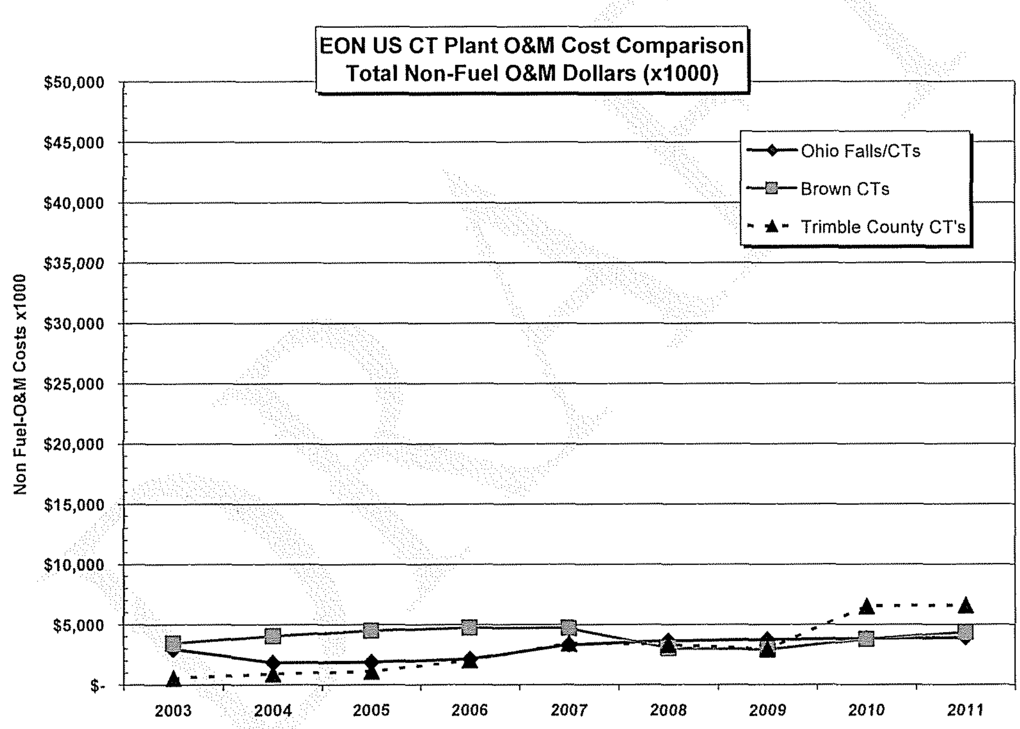

Figure 9.2-3
US CT Plant O&M Cost Comparison (Total)

Overall, the CT O&M costs reported and predicted appear reasonable given the site-specific issues that must be addressed at each station and unit, and the expected increases in the cost of overhaul and routing maintenance of CT generating units as they age. The exception to this statement may be in the older smaller CTs, most notably the units at Haefling, Zorn 1, and Paddy's Run (Units 11 and 12). O&M expenditures at these units may not actually be adequate to ensure the long-term reliability of the units. From the review of the maintenance activities and operating data for the larger units, it would appear the maintenance activities are consistent with the OEM recommendations and, therefore, appropriate to ensure the long-term reliability of the units.

Costs per Unit of Output Discussion

Figure 9.2-3 provides a representation of the CT station O&M costs on a total dollar basis. It is also helpful to examine these costs on the basis of the cost per unit of energy output. Figure 9.2-4 provides such a comparison. Because of the variation introduced through short-term changes in generation or expenditures, Figure 9.2-4 also includes the historical and forecast generation from each station.

The combination of generation and O&M costs in the same graphical reference helps to explain the variability in the historical data, especially when comparing 2003 and 2004 data. Clearly, the low $/MWh experienced in 2004 was a result of the increase in generation and the converse is true in 2003. This figure also reflects the expected increases in generation from the Trimble County units between now and 2012.

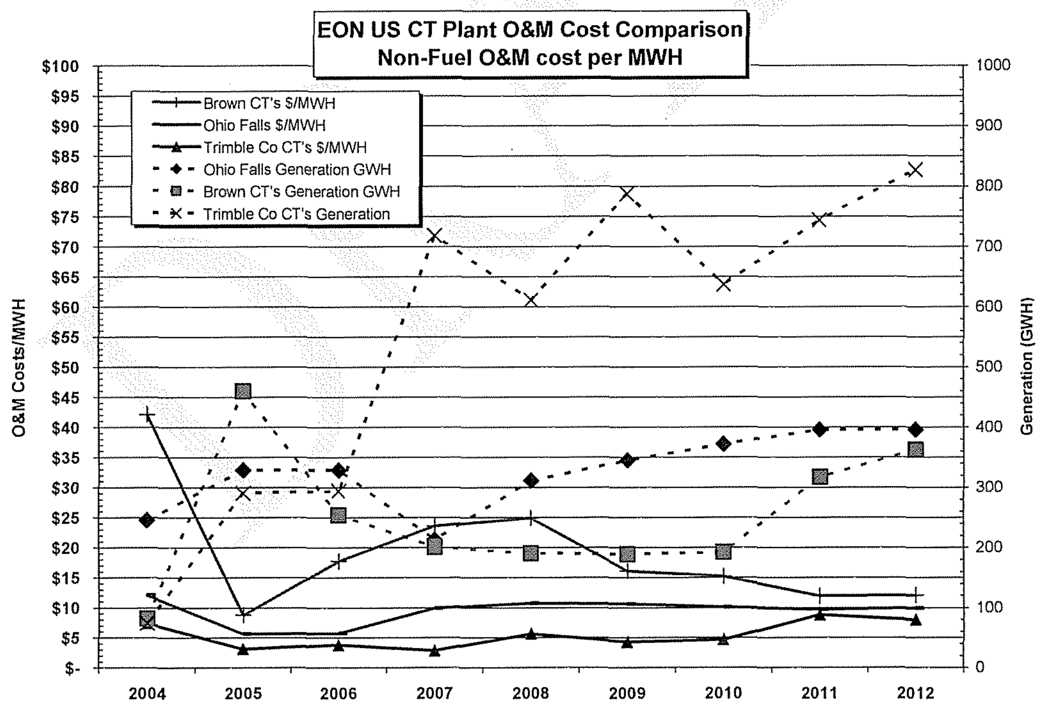

Figure 9.2-4
US CT Plant O&M Cost Comparison (per MWh)

9.2.2 *Fuel Costs*

Black & Veatch has reviewed the fuel cost forecast provided by EON for the 2008 through 2012 planning period. A high-level review was performed using EON-provided historical and projected fuel costs, specific fuel supply contracts, historical and forecast fuel data available in Global Energy databases, and information available in the Energy Information Administration 2008 Outlook. Based on this high-level review, it is Black & Veatch's opinion that the EON-projected fuel costs appear to be reasonable.

9.3 Projected Capital Expenditures

9.3.1 *Introduction*

Black & Veatch has reviewed the projected capital costs for each of the generating stations. The summary levels of these projected capital costs are included in Appendix A.2. This review included historical capital expenditure, and forecast expenditures through 2012, as well as the longer term plan through 2017. Tables A.2-1 and A.2-2 provide these costs and detail descriptions. The objective of the review was to evaluate whether or not the costs appear reasonable and adequate to address the long-term needs of the fleet and the respective units.

9.3.2 *General Observations*

Overall, the capital costs reported and predicted appear reasonable. The costs for all of the plants reflect the required expenditures based upon condition assessment and specific needs at each site. EON has identified in-depth capital projects for the plants through 2012. A review indicated that the projects are justified, based on past repair/replacements, maintenance, and inspection and testing. Several of the projects are non-recurring capital projects related to life extension or regulatory compliance that are included in the planning period. Further environmental related projects are also potentially required.

9.3.3 *Station Level Observations*

The information that follows provides select station level observations based on Black & Veatch review of the pertinent capital budgets and plans:

- Trimble County Unit 1 – The station's planned major capital project work includes controls upgrades, ID fan VFD replacement, material handling equipment, boiler lower slope tube replacement, FGD module liner replacement, precipitator fifth field rebuild, boiler outage capital, and BOP equipment upgrades or replacement as required. These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.

- Mill Creek – The station's major capital project work (planned or in-process) includes FGD refurbishment, landfill expansion, SO_3 mitigation (MC3, MC4), limestone grinding capacity increase, boiler component replacement, condenser retubing (MC1, MC2, MC3), boiler water makeup system, SCR catalyst regeneration, material handling upgrades, generator stator rewinds (MC1, MC2, MC3, MC4), turbine overhaul work, and BOP equipment upgrades or replacement as required. These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.
- Cane Run – The station's major capital project work (planned or in-process) includes FGD life extension, new landfill, boiler component replacement, barge unloader, precipitator rebuild (CR6), generator stator rewind (CR6), turbine overhaul work, and BOP equipment upgrades or replacement as required. These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.
- Ghent - The station's major capital project work (planned or in-process) includes new FGD units (GH2, GH3, GH4), new SCR unit (GH2), new ash pond and ash unloading to barge projects, boiler component replacement, cooling tower cell rebuild, generator stator rewinds (GH1, GH2, GH3, GH4), SCR catalyst replacement/addition, controls modernization (GH1, GH2, GH3, GH4), spill prevention containment countermeasures, turbine overhaul work, and BOP equipment upgrades or replacement as required. These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.
- E.W. Brown (Coal) – The station's major capital project work (planned or in-process) includes new FGD (BR1, 2, 3), new SCR (BR3), ash pond expansion, generator rewinds (BR1, BR2, BR3), boiler component replacement, controls replacement continuation (BR1, BR2, BR3), turbine overhaul work, and BOP equipment upgrades or replacement as required. These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.
- E.W. Brown (CT) – The station's planned major capital project work includes a C-Inspection and Parts Reconditioning (BRCT6, BRCT9,

BRCT10), and 11N2 Controls Upgrade (BRCT5, BRCT8, BRCT9, BRCT10, BRCT11). These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.

- Trimble County (CT) – The station's planned major capital project work includes dynamic combustion monitor system and first-stage wheel replacement (TIL for TCCT5, 6). These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work. Trimble County CTs will also be due for hot gas path inspection maintenance that will need to be included in the capital budget at an estimated cost of $8 million per unit in the period 2008 to 2012 for at least five of the turbines, which is sooner than the long-term plan.
- Ohio Falls – The station's planned major capital project work includes the hydroturbine overhaul of each unit (OF1 through OF8). These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.
- Dix Dam – The station's planned major capital project work includes the hydroturbine overhaul of each unit (DX1, 2, 3) as well as the Johnson valve replacement for DX2. These projects are all appropriate, given the condition of the station, and appear of reasonable cost magnitude based upon the scope of work.

9.4 Key Findings

Based on interviews with plant personnel and reviews of documentation pertaining to EON projected performance and operating costs, Black & Veatch has come to the key findings summarized below:

- EON provided its 5 year projected operating costs (2008 through 2012) for Black & Veatch review. The projected operating costs appear to have sufficient provisions to meet current regulations and to achieve the planned generation and reliable operation of the facilities.
- Black & Veatch's review indicated that EON's 2008 through 2012 planned capital projects are reasonable, based on past repair, replacements, maintenance, inspection, and testing records. The capital projects identified also included critical major projects, such as creating new or extending existing landfills and ash ponds for solid waste disposal, installing new FGD units at Brown and Ghent, and installing a new SCR

unit at Brown Unit 3 and Ghent Unit 2. Several large capital projects related to life extension of generating station are also included in the plan.

- Fully developed work scope and capital costs at each station for the period after 2012 were not reported by EON. Critical nonrecurring capital projects related to life extension, and some environmental projects, are included in the long-term plan capital budget. Additional projects that are potentially required but not included as captured capital costs in the planning period from 2008 to 2012 or the longer-term plan are identified in Appendix A as Potential Long-Term Capital Projects.
- EON has exhibited the ability to successfully manage and prioritize operating costs and projections to meet changing operating environments, such as regulatory, dispatch, reliability, and return requirements. Black & Veatch is of the opinion that EON is capable of prudently assessing the potential impact of the changing operating environments and implementing cost-effective strategies to meet the requirements of these environments.

Appendix A
Performance and Operating Costs

Appendix A.1

Projected Performance and Operating Costs

Table A.1-1
E.W Brown Generating Station Performance Projection - 2008-2012
(Coal Units)

Description	Units	2008	2009	2010	2011	2012
BR1						
Net Generation	MWh	546,147	478,409	510,273	489,812	496,250
Fuel Consumed	Tons	251,726	235,276	261,582	252,065	254,849
Fuel Consumed	MMbtu	6,074,145	5,450,732	5,859,439	5,646,265	5,708,614
Net Heat Rate	BTU/KWh	11,122	11,393	11,483	11,527	11,504
EAF	Percent	88.6	83.1	88.6	87.3	87.3
Capacity Factor	Percent	61.42	53.81	57.39	55.09	55.81
EFOR	Percent	3.50	3.50	3.50	3.50	3.50
MOF+POF	Percent	7.91	13.40	7.93	9.23	9.23
Avg Coal Htg. Val	Btu/lb	12,065	11,584	11,200	11,200	11,200
BR2						
Net Generation	MWh	1,117,495	957,797	1,179,117	1,160,679	1,144,025
Fuel Consumed	Tons	471,671	432,260	547,505	539,541	531,719
Fuel Consumed	MMbtu	11,381,428	9,977,698	12,264,102	12,085,722	11,910,513
Net Heat Rate	BTU/KWh	10,185	10,417	10,401	10,413	10,411
EAF	Percent	86.2	86.5	86.9	88.0	88.0
Capacity Factor	Percent	75.93	65.08	80.12	78.87	77.74
EFOR	Percent	3.50	3.50	3.50	3.50	3.50
MOF+POF	Percent	10.33	9.97	9.62	8.54	8.54
Avg Coal Htg. Val	Btu/lb	12,065	11,541	11,200	11,200	11,200
BR2						
Net Generation	MWh	2,451,670	2,707,592	3,001,325	2,946,214	2,631,738
Fuel Consumed	Tons	1,057,484	1,268,085	1,425,638	1,399,606	1,250,153
Fuel Consumed	MMbtu	25,517,094	28,649,845	31,934,297	31,351,182	28,003,436
Net Heat Rate	BTU/KWh	10,408	10,581	10,640	10,641	10,641
EAF	Percent	88.6	78.9	77.8	83.4	83.4
Capacity Factor	Percent	64.94	71.71	79.49	78.03	69.70
EFOR	Percent	4.00	4.00	4.00	4.00	4.00
MOF+POF	Percent	7.44	17.12	18.22	12.61	12.61
Avg Coal Htg. Val	Btu/lb	12,065	11,296	11,200	11,200	11,200

Table A.1-2
Cane River Generating Station Performance Projection - 2008-2012
(Coal Units)

Description	Units	2008	2009	2010	2011	2012
CR4						
Net Generation	MWh	802,028	793,717	753,108	676,590	741,418
Fuel Consumed	Tons	389,390	386,132	367,442	330,324	361,590
Fuel Consumed	MMbtu	8,718,447	8,622,321	8,223,345	7,402,564	8,103,235
Net Heat Rate	BTU/KWh	10,871	10,863	10,919	10,941	10,929
EAF	Percent	86.2	86.5	86.9	86.8	86.8
Capacity Factor	Percent	59.07	58.46	55.47	49.83	54.60
EFOR	Percent	4.50	4.50	4.50	4.50	4.50
MOF+POF	Percent	9.32	8.97	8.63	8.67	8.67
CR5						
Net Generation	MWh	771,470	831,205	777,615	764,553	767,158
Fuel Consumed	Tons	370,255	400,021	374,480	367,850	369,465
Fuel Consumed	MMbtu	8,290,008	8,932,468	8,380,848	8,243,512	8,279,702
Net Heat Rate	BTU/KWh	10,746	10,746	10,778	10,782	10,793
EAF	Percent	78.7	87.3	87.4	84.9	84.9
Capacity Factor	Percent	52.42	56.48	52.84	51.95	52.13
EFOR	Percent	4.50	4.50	4.50	4.50	4.50
MOF+POF	Percent	16.84	8.18	8.13	10.58	10.58
CR6						
Net Generation	MWh	1,355,377	1,229,774	1,314,298	1,231,972	1,281,949
Fuel Consumed	Tons	631,511	574,128	614,582	577,416	599,299
Fuel Consumed	MMbtu	14,139,541	12,820,275	13,754,347	12,939,902	13,430,290
Net Heat Rate	BTU/KWh	10,432	10,425	10,465	10,503	10,476
EAF	Percent	86.3	77.7	86.9	85.5	85.5
Capacity Factor	Percent	64.47	58.49	62.51	58.60	60.98
EFOR	Percent	4.50	4.50	4.50	4.50	4.50
MOF+POF	Percent	9.24	17.75	8.60	9.97	9.97

Table A.1-3
Ghent Generating Station Performance Projection - 2008-2012
(Coal Units)

Description	Units	2008	2009	2010	2011	2012
GH1						
Net Generation	MWh	3,629,048	3,291,274	3,478,107	3,398,991	3,475,394
Fuel Consumed	Tons	1,660,009	1,535,766	1,623,391	1,590,015	1,626,664
Fuel Consumed	MMbtu	38,279,796	34,861,881	36,786,033	35,950,237	36,778,863
Net Heat Rate	BTU/KWh	10,548	10,592	10,576	10,577	10,583
EAF	Percent	90.4	83.1	90.5	86.3	86.3
GH2						
Net Generation	MWh	3,005,740	2,907,911	2,931,032	3,252,193	2,837,648
Fuel Consumed	Tons	1,252,258	1,297,097	1,336,118	1,486,912	1,298,386
Fuel Consumed	MMbtu	30,317,154	29,778,772	30,276,431	33,619,073	29,356,508
Net Heat Rate	BTU/KWh	10,086	10,241	10,330	10,337	10,345
EAF	Percent	86.8	79.5	87.2	86.2	86.2
GH3						
Net Generation	MWh	3,572,526	3,525,865	3,062,752	3,473,039	3,455,596
Fuel Consumed	Tons	1,732,707	1,740,239	1,512,148	1,720,041	1,710,187
Fuel Consumed	MMbtu	39,956,217	39,503,422	34,265,281	38,890,137	38,667,328
Net Heat Rate	BTU/KWh	11,184	11,204	11,188	11,198	11,190
EAF	Percent	88.6	88.6	89.2	86.3	86.3
GH4						
Net Generation	MWh	3,005,303	3,549,104	3,467,018	3,482,419	3,501,070
Fuel Consumed	Tons	1,394,653	1,697,907	1,660,953	1,671,912	1,680,195
Fuel Consumed	MMbtu	32,409,099	38,542,492	37,637,188	37,801,933	37,989,206
Net Heat Rate	BTU/KWh	10,784	10,860	10,856	10,855	10,851
EAF	Percent	77.9	88.8	77.4	85.9	85.9

Table A.1-4 Green River Generating Station Performance Projection - 2008–2012 (Coal Units)						
Description	**Units**	**2008**	**2009**	**2010**	**2011**	**2012**
GR3						
Net Generation	MWh	292,285	269,411	272,248	247,150	242,035
Fuel Consumed	Tons	165,635	154,712	156,431	142,305	139,298
Fuel Consumed	MMbtu	3,802,971	3,504,221	3,535,348	3,216,083	3,148,125
Net Heat Rate	BTU/KWh	13,011	13,007	12,986	13,013	13,007
EAF	Percent	86.2	77.2	86.3	86.3	86.3
GR4						
Net Generation	MWh	601,735	533,332	424,093	378,728	337,087
Fuel Consumed	Tons	296,794	269,839	221,477	198,994	178,070
Fuel Consumed	MMbtu	6,814,398	6,111,843	5,005,378	4,497,255	4,024,373
Net Heat Rate	BTU/KWh	11,325	11,460	11,803	11,875	11,939
EAF	Percent	85.8	85.7	85.8	85.9	85.9

Table A.1-5
Mill Creek Generating Station Performance Projection - 2008-2012
(Coal Units)

Description	Units	2008	2009	2010	2011	2012
MC1						
Net Generation	MWh	1,921,840	2,016,292	1,666,805	1,891,120	1,767,820
Fuel Consumed	Tons	893,979	936,131	773,932	886,954	829,547
Fuel Consumed	MMbtu	20,329,087	21,325,061	17,630,160	20,000,819	18,706,293
Net Heat Rate	BTU/KWh	10,578	10,576	10,577	10,576	10,582
EAF	Percent	85.7	91.1	78.6	87.6	87.6
MC2						
Net Generation	MWh	2,051,350	1,890,424	1,785,141	1,834,453	1,934,727
Fuel Consumed	Tons	972,996	896,252	846,043	877,810	926,338
Fuel Consumed	MMbtu	22,125,930	20,416,616	19,272,868	19,794,619	20,888,916
Net Heat Rate	BTU/KWh	10,786	10,800	10,796	10,790	10,797
EAF	Percent	90.3	84.2	85.4	87.3	87.3
MC3						
Net Generation	MWh	2,803,296	2,720,328	2,903,068	2,509,899	2,896,611
Fuel Consumed	Tons	1,302,227	1,264,364	1,348,913	1,178,338	1,359,668
Fuel Consumed	MMbtu	29,612,645	28,802,205	30,728,232	26,571,509	30,660,506
Net Heat Rate	BTU/KWh	10,564	10,588	10,585	10,587	10,585
EAF	Percent	90.0	84.9	85.4	85.7	85.7
MC4						
Net Generation	MWh	3,267,426	3,462,853	3,250,819	3,443,349	3,221,023
Fuel Consumed	Tons	1,517,485	1,612,574	1,515,589	1,619,527	1,514,977
Fuel Consumed	MMbtu	34,507,602	36,734,436	34,525,110	36,520,339	34,162,720
Net Heat Rate	BTU/KWh	10,561	10,608	10,620	10,606	10,606
EAF	Percent	85.0	90.6	85.5	87.3	87.3

Table A.1-6
Trimble County Generating Station Performance Projection - 2008-2012
(Coal Units)

Description	Units	2008	2009	2010	2011	2012
TC1 (100%)						
Net Generation	MWh	4,114,025	3,437,532	4,084,238	3,741,178	4,085,228
Fuel Consumed	Tons	1,793,089	1,546,236	1,862,251	1,722,667	1,881,160
Fuel Consumed	MMbtu	42,298,963	35,424,268	42,124,115	38,587,744	42,137,987
Net Heat Rate	BTU/KWh	10,282	10,305	10,314	10,314	10,315
EAF	Percent	94.9	79.8	95.0	90.3	90.3
TC2 (100%)						
Net Generation	MWh	0	0	2,986,746	5,697,816	5,942,714
Fuel Consumed	Tons	0	0	1,251,094	2,374,859	2,476,768
Fuel Consumed	MMbtu	0	0	26,801,432	50,497,521	52,664,450
Net Heat Rate	BTU/KWh	0	0	8,973	8,863	8,862
EAF	Percent	0.0	0.0	81.8	85.5	89.2

Table A.1-7
Tyrone Generating Station Performance Projection - 2008-2012
(Coal Units)

Description	Units	2008	2009	2010	2011	2012
TY3						
Net Generation	MWh	320,543	363,487	298,230	318,243	313,316
Fuel Consumed	Tons	166,373	190,572	158,381	168,877	166,353
Fuel Consumed	MMbtu	4,084,465	4,592,789	3,801,137	4,053,039	3,992,480
Net Heat Rate	BTU/KWh	12,742	12,635	12,746	12,736	12,743
EAF	Percent	84.3	84.4	85.7	83.9	83.9
Capacity Factor	Percent	50.47	57.23	46.96	50.11	49.33
Avg Coal Htg. Val	Btu/lb	12,275	12,050	12,000	12,000	12,000

Table A.1-8 E.W. Brown Generating Station Performance Projection - 2008-2012 (Combustion Turbine Units)						
Description	**Units**	**2008**	**2009**	**2010**	**2011**	**2012**
BR5						
Net Generation	MWh	20,191	18,692	19,718	35,377	42,270
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	242.2	222.8	238.6	430.2	513.7
Fuel Consumed	MMbtu	248,502	228,555	244,811	441,366	527,051
Net Heat Rate	BTU/KWh	12,308	12,227	12,416	12,476	12,469
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	1.97	1.82	1.92	3.45	4.12
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Starting Reliability	Percent	96.5	96.5	96.5	96.5	96.5
BR6						
Net Generation	MWh	57,893	61,953	57,395	87,951	100,949
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	596.5	638.4	591.5	906.0	1040.0
Fuel Consumed	MMbtu	611,978	655,035	606,861	929,602	1,066,996
Net Heat Rate	BTU/KWh	10,571	10,573	10,573	10,569	10,570
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	4.29	4.59	4.25	6.52	7.48
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Starting Reliability	Percent	96.5	96.5	96.5	96.5	96.5
BR7						
Net Generation	MWh	52,256	51,051	56,913	86,013	102,994
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	537.6	525.3	585.5	884.8	1059.5
Fuel Consumed	MMbtu	551,575	538,933	600,738	907,828	1,087,035
Net Heat Rate	BTU/KWh	10,555	10,557	10,555	10,555	10,554
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	3.87	3.78	4.22	6.38	7.63
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Starting Reliability	Percent	96.5	96.5	96.5	96.5	96.5

Table A.1-8 (Continued)
E.W. Brown Generating Station Performance Projection - 2008-2012
(Combustion Turbine Units)

Description	Units	2008	2009	2010	2011	2012
BR8						
Net Generation	MWh	15,114	16,571	15,499	28,290	30,527
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	181.6	200.8	190.8	350.9	377.4
Fuel Consumed	MMbtu	186,332	206,023	195,785	360,004	387,199
Net Heat Rate	BTU/KWh	12,328	12,433	12,632	12,725	12,684
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	1.63	1.78	1.67	3.05	3.29
Eqv Full Load Run	Hours	129	142	132	242	261
EOH/Hr Factor		8.1	5.1	6.6	6.5	7.3
BR9						
Net Generation	MWh	16,507	12,625	13,585	26,509	30,912
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	198.6	152.9	166.6	326.4	384.1
Fuel Consumed	MMbtu	203,759	156,877	170,924	334,933	394,099
Net Heat Rate	BTU/KWh	12,344	12,426	12,582	12,635	12,749
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	1.78	1.36	1.46	2.85	3.33
Eqv Full Load Run	Hours	141	108	116	227	264
EOH/Hr Factor		6.0	5.2	6.4	5.9	6.6
BR10						
Net Generation	MWh	14,110	13,907	14,677	25,617	26,167
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	170.7	167.6	180.3	317.1	323.2
Fuel Consumed	MMbtu	175,153	171,971	185,006	325,302	331,609
Net Heat Rate	BTU/KWh	12,414	12,366	12,605	12,699	12,673
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	1.52	1.50	1.58	2.76	2.82
Eqv Full Load Run	Hours	121	119	125	219	224
EOH/Hr Factor		6.7	4.9	5.7	6.0	7.1
BR11						
Net Generation	MWh	13,828	13,875	14,451	27,158	28,679
Oil Consumed	Gals	0	0	0	0	0
Gas Consumed	MMCF	166.9	166.4	176.8	338.4	356.5
Fuel Consumed	MMbtu	171,225	170,770	181,369	347,236	365,743
Net Heat Rate	BTU/KWh	12,382	12,308	12,551	12,786	12,753
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	1.49	1.49	1.56	2.92	3.09
Eqv Full Load Run	Hours	118	119	124	232	245
EOH/Hr Factor		6.1	4.1	5.9	7.1	6.4

Table A.1-9
Trimble County Generating Station Performance Projection – 2008-2012
(Combustion Turbine Units)

Description	Units	2008	2009	2010	2011	2012
TC5						
Net Generation	MWh	166,316	221,710	136,058	143,845	188,455
Gas Consumed	MMCF	1744	2331	1424	1500	1963
Fuel Consumed	MMbtu	1,787,298	2,389,709	1,459,306	1,537,666	2,012,557
Net Heat Rate	BTU/KWh	10,746	10,779	10,726	10,690	10,679
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	11.87	15.82	9.71	10.26	13.45
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Fired Hours	Cum.	3,511	4,897	5,747	6,646	7,824
Factored Starts per Fired Hour	Cum.	0.193	0.180	0.185	0.192	0.188
Fact. Starts per year	Projected	94.0	205.1	180.9	210.2	196.1
Factored Starts per Fired Hour	Period	0.09	0.15	0.21	0.23	0.17
TC6						
Net Generation	MWh	119,198	179,464	148,756	131,723	131,794
Gas Consumed	MMCF	1245	1879	1556	1367	1368
Fuel Consumed	MMbtu	1,275,644	1,925,507	1,594,816	1,401,559	1,402,178
Net Heat Rate	BTU/KWh	10,702	10,729	10,721	10,640	10,639
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	8.50	12.80	10.61	9.40	9.40
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Factored Starts per Fired Hour	Cum.	0.216	0.227	0.221	0.231	0.242
Fact. Starts per year	Total	198.8	287.5	180.8	244.2	262.7
Factored Starts per Fired Hour	Period	0.27	0.26	0.19	0.30	0.32

Table A.1-9 (Continued)
Trimble County Generating Station Performance Projection - 2008-2012
(Combustion Turbine Units)

Description	Units	2008	2009	2010	2011	2012
TC7						
Net Generation	MWh	95,902	141,980	117,801	137,589	138,259
Gas Consumed	MMCF	997	1481	1226	1427	1431
Fuel Consumed	MMbtu	1,022,030	1,517,734	1,257,097	1,462,480	1,466,435
Net Heat Rate	BTU/KWh	10,657	10,690	10,671	10,629	10,606
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Factored Starts	Cum.	562	697	890	1,003	1,179
Fired Hours	Cum.	2,735	3,622	4,359	5,218	6,083
Factored Starts per Fired Hour	Cum.	0.206	0.192	0.204	0.192	0.194
Fact. Starts per year	Total	112.2	134.8	193.1	112.9	176.1
Factored Starts per Fired Hour	Period	0.19	0.15	0.26	0.13	0.20
TC8						
Net Generation	MWh	93,843	88,089	96,185	121,054	132,793
Gas Consumed	MMCF	974	916	999	1252	1372
Fuel Consumed	MMbtu	998,619	938,450	1,024,405	1,283,021	1,405,912
Net Heat Rate	BTU/KWh	10,641	10,653	10,650	10,599	10,587
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Factored Starts	Cum.	617	796	931	1,017	1,147
Fired Hours	Cum.	3,513	4,063	4,665	5,421	6,251
Factored Starts per Fired Hour	Cum.	0.176	0.196	0.200	0.188	0.183
Fact. Starts per year	Total	168.0	179.0	134.8	86.1	130.3
Factored Starts per Fired Hour	Period	0.29	0.33	0.22	0.11	0.16

Table A.1-9 (Continued)
Trimble County Generating Station Performance Projection - 2008-2012
(Combustion Turbine Units)

Description	Units	2008	2009	2010	2011	2012
TC9						
Net Generation	MWh	73,413	79,363	79,478	107,226	126,906
Gas Consumed	MMCF	759	822	823	1107	1310
Fuel Consumed	MMbtu	778,352	842,786	843,875	1,134,440	1,342,886
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Starting Reliability	Percent	95	95	95	95	95
Factored Starts	Cum.	555	739	897	995	1,078
Fired Hours	Cum.	2,954	3,450	3,947	4,617	5,410
Factored Starts per Fired Hour	Cum.	0.188	0.214	0.227	0.216	0.199
Fact. Starts per year	Total	116.8	184.8	157.6	98.2	82.7
Factored Starts per Fired Hour	Period	0.25	0.37	0.32	0.15	0.10
TC10						
Net Generation	MWh	62,278	77,005	58,756	102,518	109,214
Gas Consumed	MMCF	644	798	609	1059	1128
Fuel Consumed	MMbtu	660,523	818,330	624,618	1,085,606	1,155,745
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
Starting Reliability	Percent	95	95	95	95	95
Factored Starts	Cum.	454	585	695	779	840
Fired Hours	Cum.	3,103	3,584	3,952	4,592	5,275
Factored Starts per Fired Hour	Cum.	0.146	0.163	0.176	0.170	0.159
Fact. Starts per year	Total	64.0	130.1	110.6	83.5	61.8
Factored Starts per Fired Hour	Period	0.16	0.27	0.30	0.13	0.09

Table A.1-10
Paddy's Run Generating Station Performance Projection - 2008-2012
(Combustion Turbine Units)

Description	Units	2008	2009	2010	2011	2012
PR11						
Net Generation	MWh	-	192.00	48.00	312.00	516.00
Oil Consumed	Gals	-	-	-	-	-
Gas Consumed	MMCF	-	2.97	0.74	4.83	7.99
Fuel Consumed	MMbtu	-	3,046.30	761.58	4,950.14	8,186.88
Net Heat Rate	BTU/KWh	-	15,866.15	15,866.15	15,865.82	15,866.05
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	-	0.18	0.05	0.30	0.49
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
PR12						
Net Generation	MWh	92.00	-	-	138.00	230.00
Oil Consumed	Gals	-	-	-	-	-
Gas Consumed	MMCF	1.56	-	-	2.35	3.91
Fuel Consumed	MMbtu	1,603.61	-	-	2,405.37	4,008.98
Net Heat Rate	BTU/KWh	17,430.57	-	-	17,430.20	17,430.35
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	0.05	-	-	0.07	0.11
EFOR	Percent	N/A	N/A	N/A	N/A	N/A
PR13						
Net Generation	MWh	35,303.80	30,950.60	34,962.60	59,191.30	71,080.90
Oil Consumed	Gals	-	-	-	-	-
Gas Consumed	MMCF	351.11	308.12	347.78	588.18	706.61
Fuel Consumed	MMbtu	359,888.47	315,823.62	356,471.12	602,880.40	724,277.40
Net Heat Rate	BTU/KWh	10,194.04	10,204.12	10,195.78	10,185.29	10,189.48
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	2.55	2.24	2.53	4.28	5.14
EFOR	Percent	N/A	N/A	N/A	N/A	N/A

Table A.1-11
Cane Run Generating Station Performance Projection - 2008-2012
(Combustion Turbine Units)

Description	Units	2008	2009	2010	2011	2012
CR11						
Net Generation	MWh	-	56.00	-	112.00	238.00
Oil Consumed	Gals	-	-	-	-	-
Gas Consumed	MMCF	-	0.90	-	1.81	3.84
Fuel Consumed	MMbtu	-	925.17	-	1,850.33	3,931.70
Net Heat Rate	BTU/KWh	-	16,520.80	-	16,520.80	16,519.73
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	-	0.05	-	0.09	0.19
EFOR	Percent	N/A	N/A	N/A	N/A	N/A

Table A.1-12 Zorn Generating Station Performance Projection - 2008-2012 (Combustion Turbine Units)						
Description	**Units**	**2008**	**2009**	**2010**	**2011**	**2012**
ZN1						
Net Generation	MWh	56.00	56.00	56.00	-	112.00
Oil Consumed	Gals	-	-	-	-	-
Gas Consumed	MMCF	1.05	1.05	1.05	-	2.09
Fuel Consumed	MMbtu	1,072.05	1,072.05	1,072.05	-	2,144.10
Net Heat Rate	BTU/KWh	19,143.71	19,143.71	19,143.71	-	19,143.71
EAF	Percent	N/A	N/A	N/A	N/A	N/A
Capacity Factor	Percent	0.05	0.05	0.05	-	0.09
EFOR	Percent	N/A	N/A	N/A	N/A	N/A

Table A.1-13
Hydroelectric Generating Station Performance Projection - 2008-2012

Description	Units	2008	2009	2010	2011	2012
Ohio Falls						
Net Generation	MWh	252,979	278,854	307,740	333,679	358,501
Capacity Factor	Percent	51.48	54.14	57.12	59.33	61.17
Dix Dam						
Net Generation	MWh	53,800	53,800	53,800	53,800	53,800
Capacity Factor	Percent	25.59	24.28	22.01	22.01	22.01

Appendix A.2

Projected Capital Costs

Table A.2-1
2008 through 2012
Projected Total Capital Costs by Station ($000)

Total By Location	2008	2009	2010	2011	2012
MC	$ 13,600	$ 27,315	$ 53,180	$ 39,950	$ 31,935
TC1, TC CTs	2,716	12,587	6,085	19,015	4,177
CR	5,540	23,523	8,167	23,784	20,215
OF/LOU CT	12,970	14,946	23,638	21,415	19,841
GH	39,840	27,403	26,230	32,955	26,440
BR, DX	5,521	18,652	20,814	22,041	29,718
BRCT	9,450	1,708	2,553	14,037	14,658
GR	700	1,730	1,505	840	805
TY	910	747	1,460	1,867	3,779
Station Capital	$ 91,247	$ 128,611	$ 143,632	$ 175,904	$ 151,568
Generation Services (GS)	$ 4,658	$ 780	$ 393	$ 378	$ 13,972
Project Engineering (PE)	650,432	209,338	91,256	106,600	95,500
VP	(7,889)	(15,151)	(6,657)		
IT	500	500	500	500	500
Base Capital					
Base Capital Reduction					
Generation Total Capital	738,948	324,078	229,124	283,382	261,540
Long-Term Plan Capital					
Additional Capital and Sensitivities (ADD)		8,000	16,000	16,000	
Total Capital	$ 738,948	$ 332,078	$ 245,124	$ 299,382	$261,540

Table A.2-2
2008 through 2017
Major Long-Term Projected Capital Projects ($000)

Loc.	Project Description	Total Forecast	Pre 2008	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
PE	TC2 non AQCS (LGE Cost at 75%)	$ 594,397	$ 338,106	$ 179,809	$ 69,633	$6,850	$ -	$ -					
PE	TC2 AQCS (LGE Cost at 75%)	$ 230,246	$ 90,146	$ 116,509	$ 23,591	$ -	$ -	$ -					
OF	Ohio Falls Rehabilitation	$ 126,465	$ 27,000	incl. in OF	incl. in OF	incl. in OF	incl. in OF	incl. in OF	$ 20,986				
PE	New Base Unit 1 (with AQCS)	$ 4,000	$4,000	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ -	$ -	$ -
LTP	Expansion Plan (Combined Cycle CT)	$-	$ -	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ -	$ -	$ -
PE	Brown FGD	$ 376,902	$ 108,826	$ 186,804	$ 81,272	$ -	$ -	$ -					
PE	Ghent 4 FGD	$ 164,462	$ 130,944	$ 33,518	$ -	$ -	$ -	$ -					
PE	Ghent SO_2 Common	$ 157,920	$ 124,622	$ 33,298	$ -	$ -	$ -	$ -					
PE	Ghent 1&2 FGD	$ 140,676	$ 52,499	$ 75,142	$ 13,035	$ -	$ -	$ -					
PE	Ghent 3 FGD	$ 134,193	$ 134,193	$ -	$ -	$ -	$ -	$ -					
PE	Brown 3 SCR	$ 126,000	$1,000	$2,000	$ -	$ 25,000	$ 45,000	$ 53,000					
PE	Wet ESP	$-	$ -	$ -	$ -	$ -	$ -	$ -	$-	$ -	$ -	$ -	$ -
PE	Brown Ash Pond - Phase I	$73,000	$ 34,758	$ 11,229	$6,607	$ 20,406	$ -	$ -					
PE	Cane Run New Landfill	$47,000	$200	$200	$2,000	$ 20,000	$ 24,600	$ -					
PE	GH Ash Pond/Landfill	$56,059	$270	$1,000	$2,789	$2,000	$ 20,000	$ 20,000	$ 10,000				
PE	TC Ash / Gypsum Ponds (Phase I)	$44,000	$ -	$ -	$ -	$ 12,000	$ 13,000	$ 13,500	$ 5,500	$ -	$ -	$ -	$ -
PE	GH & TC Sorbent Injection for SO_3	$24,099	$5,765	$6,923	$3,411	$ -	$ -	$ -			$6,400	$1,600	
PE	Brown Ash Pond - Phase II	$27,000	$ -	$ -	$ -	$ -	$4,000	$9,000	$ 4,000	$5,000	$5,000	$ -	$ -
PE	TC Ash / Gypsum Ponds (ATB Ext)	$ 7,318	$1,318	$4,000	$2,000	$ -	$ -	$ -					
PE	MC4 SO_3 Mitigation	$ 5,000	$ -	$ -	$ -	$5,000	$ -	$ -					
PE	MC3 SO_3 Mitigation	$ 5,000	$ -	$ -	$5,000	$ -	$ -	$ -					
PE	Ghent 2 SCR	$ 149,800	$3,000	$ -	$ -	$ -	$ -	$ -	$ 58,700	$ 58,700	$ 29,400	$ -	$ -
GS	CEMS Mercury Monitoring		incl. in GS	incl. in GS	incl. in GS	incl. in GS	incl. in GS	incl. in GS					
LTP	MC Barge Unloading	$12,000							$ 12,000				
LTP	CR Barge Unloader	$ 8,000							$ 8,000				
LTP	MC Stator Rewind (Units 1,2,3,&4)	$ 7,000				incl. in MC	incl. in MC	incl. in MC	$ 7,000				
LTP	BR2 Generator Rewind/Restack	$15,000							$-	$5,000	$ 10,000	$ -	$ -
LTP	BR3 Generator Rewind/Restack	$19,000				incl. in BR	incl. in BR	incl. in BR					
LTP	GH Generator Rewind (U.1,2,3&4)	$39,200						incl. in GH	$-	$ 15,000	$ 15,000	$ -	$ -
LTP	CR6 Generator Rewind	$15,000							$ 15,000				
LTP	PR13 C Inspection	$ 7,000							$ 7,000				
LTP	BR CT GT24s (C Inspection)	$63,200		incl. in BR	incl. in BR	incl. in BR	incl. in BR	incl. in BR	$-	$ -	$ 31,600	$ 31,600	$ -
LTP	BR CT 11N2s (C Inspections)	$37,500		incl. in BR	incl. in BR	incl. in BR	incl. in BR	incl. in BR	$-	$ 31,800	$4,500	$1,200	$ -
LTP	GSU Bushing / Transformer	$ 5,000							$ 5,000	$ -	$ -	$ -	$ -
LTP	Upgrading Black Start Capability	$50,000							$ 12,500	$ 12,500	$ 12,500	$ 12,500	$ -
LTP	MC FGD Refurbishment	$46,000			incl. in MC	incl. in MC	incl. in MC	incl. in MC	$ 4,000	$5,000	$ -	$ -	$ -
LTP	CR FGD Life Extension	$40,500			incl. in CR	incl. in CR	incl. in CR	incl. in CR	$ 20,000	$ -	$ -	$ -	$ -
LTP	TC Ash / Gypsum Ponds (Phase II)	$44,000		$ -	$ -	$ -	$ -	$ -	$-	$8,000	$ 14,000	$ 14,000	$8,000
LTP	BR Ash Pond Extension (Phase III)	$ 4,000		$ -	$ -	$ -	$ -	$ -	$-	$ -	$ -	$4,000	$ -
LTP	Expansion Plan (Combined Cycle CT)	after 2017					$ -	$ -	$-	$ -	$3,113	$9,340	$ 18,680
ADD	TC CT Hot Gas Path Inspections	$56,000		$ -	$8,000	$ 16,000	$ 16,000	$ -	$-	$8,000	$ -	$ -	$8,000

Table A.2-3 2008 through 2017 Potential Long-Term Capital Projects ($000)	
	Approximate Order of Magnitude Forecast Cost
MC1,2 SCR (Based on Future Regulation)	$250,000
CR4,5,6 SCR (Based on Future Regulation)	$300,000
BR1,2 SCR (Based on Future Regulation)	$250,000
SO_3 Operating Permit Limits (< 5 ppm)	TBD
Mercury Control at All Locations	TBD
CO_2 Reduction at All Locations	$0
MC1 Cooling Tower (316b)	$12,000
CR Cooling Towers (316b) CR1,2,3	$20,000
Tear down Ghent 3/4 Chimney	$9,500
GH2 Chimney Relining/FGD Connection	$53,000
Precipitator Modifications	TBD
PR Environmental Retired Steam Plant - PR Stack Removal	TBD
Dix Dam Restoration	TBD
MC3/4 Condenser Re-Tube	$4,400
MC3 Primary Superheater	$5,150
MC Feedwater Heaters	$4,000
MC3 GSU Transformer	$550
MC Gypsum Dryer (Marketing)	TBD
GH1 Steam Turbine IP Blade Rings	$3,275
GH2 Steam Turbine 1st Stage Buckets	$600
GH1 Condenser Re-Tube / GH2 Inserts	$2,000
GH2/3/4 Condenser Inserts	$1,050
GH2 Auxiliary Transformer 2B	$350
GH1 Boiler Drum PSV	$75
GH3/4 Reheaters, Superheater Spacers	TBD
GH 1/2 Lower Slopes	TBD
GH2 Deaerator	$900
BR1/2/3 Water Walls	TBD
BR1 Secondary Superheater Pendants	$650
BR2 Superheater Platen Assemblies	$650
BR2 Boiler Insulation Replace	$250
BR1 LP Rotor Replace and HP-IP Overhaul	$5,000
BR3 LP Rotor L-0 Blades	$2,000
BR1 Rotor Rewind	$1,000
BRCT 3rd Stage Vane Cracking	TBD
CR 4/5/6 Water Walls	TBD
CR4 Reheater	$3,000
CR5 Primary Superheater	$4,000
CR6 Convection Superheater	$5,000
CR4 Steam Turbine Gearbox	$1,000
CR5 Steam TurbineLife Assesment (2014)	TBD
CR6 Steam Turbine Brg Sub-Synch Vib.	TBD
TC1 FGD FRP Piping	TBD
TC1 Ammonia Vaporization Winterization	TBD
GR Turbine Water Induction	TBD

Appendix B

Environmental Description

B.1.1 Trimble County Generating Station Environmental Review

Permit Status and Regulatory Compliance

Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Key documents provided by EON for this review included the following:

- June 20, 2003 (issuance date) Kentucky Division of Air Quality (KDAQ) Air Quality Permit (Permit No. V-02-043, Revision 3. on February 29, 2008).
- 2007 Emissions Inventory Spreadsheet.
- EON internal correspondence dated July 8, 2008, indicating air permit renewal status.
- 2007 Annual Air Compliance Certification dated January 28, 2008.
- Letter for Kentucky Department for Environmental Protection (KDEP) Air Compliance Inspection Report dated December 19, 2007.
- External environmental audit by Murdock, Goldenburg, Schneider, and Groh, LPA dated February 2007.
- External environmental audit by Murdock, Goldenburg, Schneider, and Groh, LPA dated August 20, 2007.
- Application submittal letter to the KDAQ requesting to install one sulfur trioxide (SO_3) mitigation systems on Unit 1, dated August 2, 2007.
- KDAQ determination of no permit required for the installation of one SO_3 mitigation systems on Unit 1, dated August 7, 2007.
- October 1, 2002 (effective date) Kentucky Pollutant Discharge Elimination System (KPDES) Permit (Permit No. KY0041971) issued by KDEP.
- Monthly Discharge Monitoring Reports for calendar year 2007.
- April 9, 2007, KPDES Permit Renewal Application with additional information on November 30, 2007.
- September 2007 Groundwater Protection Plan.
- Groundwater Monitoring Plan, December 2000.
- Semiannual Groundwater Monitoring Reports for calendar year 2007.
- May 1996 Modification KDEP Solid Waste Disposal Facility Permit (Permit No. 112-00003).
- September 2007 Best Management Practices and Spill Prevention, Control and Countermeasures (SPCC) Plan.

- Trimble County Station Process Safety Management Program and Risk Management Plan Elements document, dated July 1, 2008.
- Toxic Release Inventory (TRI) Spreadsheet for 2007.
- Tier Two Emergency and Hazardous Chemical Inventory Report for 2007.
- 2007 Hazardous Waste Annual Report Form 1.
- Selected correspondence with regulatory agencies, including December 19, 2007, letter for KDEP Air Compliance Inspection Report and other letters as cited in this report.
- 2008 to 2012 MTP Operating Plan (undated).

Black & Veatch also obtained a recent summary of the facility's compliance status from the US Environmental Protection Agency (EPA) "Enforcement and Compliance History Online" (ECHO) database on August 14, 2008.

B.1.1.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at the Trimble County (TC) Generating Station for the TC1 coal facility and the simple cycle gas units TC Units 5-10.

B.1.1.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this documentation review was an attempt to identify issues that may be of potential concern. It is possible that other compliance issues exist that were not identified in the available information.

B.1.1.2.1 Air Program Compliance. The Trimble County Generating Station's air permit is a combined Prevention of Significant Deterioration (PSD) and Part 70 Title V operating permit (Permit No. V-02-043) issued to LG&E on June 20, 2003. The permit has since undergone three revisions, the latest being on February 29, 2008. The combined PSD/Part 70 operating permit is in effect for 5 years from the effective date. A renewal application must be submitted at least 6 months prior to the expiration of the permit (June 20, 2008), which made a renewal application due to the KDEP no later than December 20, 2007. It should be noted that the term for the Acid Rain permit (included in the combined permit) for TC1 is coincident with the term of the Operating Permit. The latest version of the permit expired on June 20, 2008. EON has indicated that it has submitted a renewal application, reviewed and commented on an early draft permit, and anticipates KDAQ issuing a final draft late summer 2008. In the interim, EON indicated that it was operating under a permit shield (401 KAR 52:020, Section 12). (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical.)

The following identified items are findings from the document review:

- The existing air emission sources at the Trimble County Generating Station include a 500 MW PC generating unit (TC1), six 150 MW simple cycle natural gas combustion turbines (CTs), a natural draft cooling tower, coal/limestone/ash handling equipment, and fuel oil storage tanks. The existing natural draft cooling tower, coal/limestone/ash handling equipment and fuel oil storage tanks will have increased utilization when TC2 becomes operational. In addition to TC2, the new equipment proposed will include a linear mechanical draft cooling tower (LMDCT), a coal blending facility, dust collectors and dust suppression equipment, an ash barge loading system, an auxiliary steam boiler, and a backup diesel generator.

  On February 13, 2007, EON submitted an application for a significant revision to amend the air permit (Permit V-02-043, Revision 2) for permitting design revisions to the TC2 project. The KDAQ accepted the significant revisions and issued a final permit (Revision 3 of this permit) on February 29, 2008. The new unit and associated equipment are under construction and are not in operation. Therefore, the new project's (TC2's) compliance with applicable air requirements was not reviewed.
- The current air construction and operating permit (Permit V-02-043, Revision 3) expired on June 20, 2008. EON has indicated that it has submitted a renewal application, reviewed and commented on an early draft permit, and anticipates KDAQ issuing a final draft late summer 2008. In the interim, EON indicated that it was operating under a permit shield (401 KAR 52:020, Section 12).

- EON has submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with permit conditions, with the exception of a few items. These and other items are noted below in greater detail:
  - The current air construction and operating permit (Permit V-02-043, Revision 3) notes the carbon monoxide (CO) emissions limit for the TC CTs is 9 ppm (by volume at 15 percent oxygen, on a dry basis), but the 2007 Annual Air Compliance Certification indicates that the TC CTs CO emission limit is 9.5 ppm. Based on the 9.5 ppm CO emission limit noted in the report, no excess emissions were reported for these units. However, no additional CO emissions information on individual TC CTs was available for review to determine if these units were exceeding their 9 ppm CO emissions limit.
  - The current air construction and operating permit (Permit V-02-043, Revision 3) notes the NO_x annual emission limit for the TC CTs is 9 ppm (by volume at 15 percent oxygen, on a dry basis) and 12 ppm on a hourly basis. The 2007 Annual Air Compliance Certification indicates that several of the TC CTs exceeded their emissions limit during the months of April, May, and June 2007. No additional information on these exceedances was available for review to determine if the hourly NO_x emissions limit was exceeded.
  - During the permitting of the TC2 project, EON voluntarily accepted NO_x and SO_2 annual emissions limits for TC1 of 5,556 and 4,822 tpy, respectively. Based on the 2007 Annual Air Compliance Certification, TC1 is in compliance with these emission limits.
  - 2007 Annual Air Compliance Certification indicates TC1 had four opacity exceedances greater than their 20 percent threshold due to unit upset or precipitator trouble. Additionally, the report indicates that the CT opacity monitors for all six units were unavailable for greater than 20 percent of their operating time. No additional information on these issues was available for review.
- In 2006, EON commissioned an external environmental audit by Murdock, Goldenburg, Schneider, and Groh, LPA. The final audit report was issued in February 2007. The results of the audit for air related issues

indicated that recordkeeping and reporting requirements related to the conditions of the permit formed the majority of the findings. In early 2007, Murdock, Goldenburg, Schneider, and Groh, LPA conducted another environmental audit, with the final report issued in August 2007. The results of the audit for air related issues was similar to the February 2007 external audit in that recordkeeping and reporting requirements related to the conditions of the permit formed the majority of the findings.

- The letter for KDEP Air Compliance Inspection Report dated December 19, 2007, indicates that KDEP conducted a tour of the facility and complete records review on December 14 and 18, 2007. The inspection report noted the aforementioned TC1 opacity and CT NO_x issues from 2007, but also noted no violations were observed.
- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

B.1.1.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is hinged on known regulatory programs, as well as these changing regulatory requirements. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs, no attempt in determining how these changes will affect this facility will be made. However, based on a review of the Trimble County Generating Station's documentation, no future plans or facility modifications were identified that would require air considerations.

B.1.1.3 Water.

B.1.1.3.1 Water Supply. Water supply for cooling water at the Trimble County Station is from the Ohio River. Drinking water is supplied by a public system. According to the SPCC Plan, three onsite groundwater supply wells were installed, but are not used.

B.1.1.3.2 Water Discharges. As authorized by the federal Clean Water Act (CWA), the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. The EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

The Trimble County Generating Station has a KPDES wastewater discharge permit (Permit No. KY0041971) issued by KDEP in 2002. The permit expired on September 30, 2007. EON submitted a renewal application in April 2007. A letter from KDEP on April 17, 2007, acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. The Trimble County Generating Station continues to operate under the terms of the 2002 permit until permit renewal is processed by KDEP. (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical.)

The 2002 KPDES permit includes limits for such wastewater discharges as cooling tower blowdown, ash treatment basin (ATB) discharge, and storm water runoff. Limits appear to be typical for large power generation facilities. The permit requires monitoring and/or reporting of such parameters as temperature, flow, selected metals, and residual chlorine. The permit also requires annual reporting of priority pollutants by analysis or engineering calculations. The ash basin is permitted as a no-release pond (no discharge).

Black & Veatch reviewed discharge monitoring reports for calendar year 2007. No issues of noncompliance were noted.

According to the EPA ECHO database, the facility was inspected in 2007, and the most recent alleged violation recorded in the database from wastewater discharge inspections and reports was in 2005. ECHO notes a report in the time period of October to December 2005 when the chlorine was 83 percent over the maximum allowed value. (Black & Veatch notes that infrequent deviations from a permit limit may be a typical expectation for an industrial facility due to such events as operational variations or laboratory problems.) ECHO indicates that no notices of violation were on file for the Trimble County Generating Station during the past 5 years.

As observed during the site visit by Black & Veatch, chloride buildup in the plant water system is a significant concern for the future. Gypsum dewatering wash water is sent to the ash pond and is not discharged. This practice has raised the chloride level in the ash pond. In its renewal application, EON has applied for a change in the KPDES permit to allow gypsum impoundment water to be pumped to the cooling tower blowdown outfall, but the renewed/revised permit has not yet been issued. Acceptance of the change to allow discharge of this water is vital in order to avoid the potential of having to install expensive evaporators to remove the chlorides.

B.1.1.4 Solid and Hazardous Waste. The Trimble County Generating Station produces combustion byproducts such as fly ash, general refuse trash, and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.1.4.1 Combustion/Coal Byproducts. The Trimble County Generating Station generates bottom ash, fly ash, boiler slag, and flue gas desulfurization (FGD) solid byproducts (gypsum). The materials accumulate in an onsite surface impoundment ATB or are placed in an onsite landfill. EON operates the landfill under a KDEP Solid Waste Disposal Facility Permit (Permit No. 112-00003) modified in 1996. For landfills, the only requirements for recordkeeping are the groundwater monitoring data that complies with the Groundwater Monitoring Plans. The construction plans for the sites are not reported on and are generally only reviewed during inspections, which typically only occur during expansion application processes. No compliance issues were identified by the state inspectors. The permit by rule for ash ponds does not require any monitoring other than that required by the KPDES permit described above in Subsection B.1.1.3.2.

According to the Groundwater Protection Plan, the ATB is lined with 3 feet of clay to prevent seepage. The ash pond receives water from fly ash and bottom ash sluicing, scrubbing of coal combustion gases, effluent from the wastewater treatment plant, and precipitation runoff.

Black & Veatch reviewed copies of the TC Groundwater Monitoring Plan and two semiannual groundwater monitoring reports for calendar year 2007. As noted in the groundwater monitoring reports, EON continues to maintain its disposal facility permit and conduct groundwater monitoring despite the fact that there have never been any landfilling activities at the facility. No waste compliance issues were noted.

As observed during the site visit by Black & Veatch, adequate long-term options for disposal and storage of combustion products are an important consideration for the Trimble County Generating Station.

- Long-term disposal of gypsum byproduct from the FGD process has not been fully resolved. EON currently has a 20 year contract with minimum take of gypsum that will be equal to 50 percent of the gypsum production at the plant. The facility and LG&E corporate personnel are formulating plans and allocating capital budget in future years for developing landfill sites near the plant to provide for disposal of the byproduct, but such plans are not finalized.

B.1.1.4.2 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance (O&M) at the Trimble County Generating Station (including office waste, maintenance waste, and other nonhazardous waste) is stored onsite in dumpsters before being transferred to a licensed commercial landfill.

B.1.1.4.3 Hazardous Waste. The Trimble County Generating Station facility is a small quantity generator of hazardous waste, defined in federal and Kentucky regulations as 220 to 2,200 pounds generated in any one calendar month (401 KAR 32 Standards Applicable to Generators of Hazardous Waste). The facility filed a 2007 Hazardous Waste Annual Report Form 1 confirming its continuing status as a small quantity generator. No hazardous waste compliance issues were noted in documents reviewed. According to the EPA ECHO database, KDEP conducted a hazardous waste inspection in July 2007 with no violations or compliance issues found.

B.1.1.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

The EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines, including process oil use in the SPCC plan. The EPA has amended the SPCC requirements of the Oil Pollution Prevention regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[1] on SPCC plans require that existing facilities operating prior to August 16, 2002, amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Trimble County Generating Station has a Best Management Practices and SPCC plan dated October 2007. This SPCC plan responds to EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. Trimble County Generating Station handles thousands of gallons of oil products, including fuel or transformer oil and lubricants. The largest oil tanks in the SPCC plan are two 100,000 gallon No. 2 fuel oil tanks with earthen berms.

[1] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

The Trimble County Generating Station's SPCC plan describes compliance with EPA regulations effective in 2009. Black & Veatch agrees with the general introductory statements in the plan that the plan "serves to fulfill the regulatory requirements" and addresses the new 2002 requirements.

According to the SPCC plan, the Trimble County Generating Station is scheduled to complete oil containment improvements associated with the SPCC plan by July 1, 2009. EON plans to continue the use of earthen berms for containment for the large storage tanks at the Trimble County Station Facility due to their size. Concrete containment structures will be constructed for the smaller oil storage facilities. Otherwise, information provided indicates that no major additional actions and expenses appear to be necessary for oil compliance.

B.1.1.6 Emergency Planning. The Trimble County Generating Station has in place a Risk Management Plan (RMP) under the chemical accident prevention provisions (40 CFR 68). The Trimble County Generating Station RMP is associated with safe ammonia storage and use onsite. Two 32,000 gallon anhydrous ammonia tanks are located onsite.

A 2008 version of Trimble County Station Process Safety Management Program and Risk Management Plan Elements document was reviewed.

Black & Veatch reviewed an inventory of chemicals used onsite as detailed in the 2007 Groundwater Protection Plan and in the 2007 TRI spreadsheet provided by EON. Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) requires certain facilities to submit an annual TRI Report to the EPA. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities and to allow better response should a chemical release occur.

According to the TRI spreadsheet, the type and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Trimble County Generating Station appear to be typical for large coal power plants. EON provided a receipt from EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

Under OSHA (29 CFR 1910 [Occupational Safety and Health Standards]) and EPA (40 CFR 372 [Toxic Chemical Release Reporting: Community Right-to-Know regulations]), facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year. This information must be provided to state emergency response commissions and the local emergency planning commissions. Black & Veatch reviewed the 2007 Tier II report for the Trimble County Generating Station and found the list to be typical for large coal power plants. The Trimble County Generation Station Tier II 2007 report was submitted to the Trimble County Emergency Planning Committee with a postal return receipt attached.

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of this information.

B.1.1.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.1.1.8 Other Environmental Issues. Observations from the document review indicated a generally high level of environmental awareness in current and recent operations of the Trimble County Generating Station facility and a proactive approach to environmental management at the facility. Professional environmental staff located at both the facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning. EON provided independent audit information demonstrating procedures for checking fine-point compliance with environmental requirements.

Documents provided by EON did not include studies of any preexisting environmental conditions at the Trimble County Generating Station site (prior to current operations) or any investigations of known soil/groundwater contamination issues from past operations including prior ash/sludge landfills/basins, from prior and ongoing management of coal and limestone onsite, and from any historical spills or other previous releases at the site. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.1.2 Mill Creek Generating Station Environmental Review

Permit Status and Regulatory Compliance

Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of this environmental section did not visit the site. Key documents provided by EON for this review included the following:

- BART Exemption Modeling for E.W. Brown Station, Ghent Station, Cane Run Station, and Mill Creek Station Facilities, dated July 2007.
- Mill Creek Station Best Available Retrofit Technology Analysis, dated September 17, 2007.
- EON email correspondence regarding KDAQ BART determination dated July 11, 2008.
- EON internal compliance audit of the PSM/RMP programs, dated April 27, 2007.
- June 1, 2003 (issuance date) Jefferson County Air Quality Permit/Title V Operating Permit (Permit No. 145-97-TV).
- Mill Creek Station Process Safety Management Program and Risk Management Plan Elements, dated April 28, 2008.
- Mill Creek Generating Station Title V Renewal Application document, dated November 29, 2007.
- 2007 Emissions Inventory Spreadsheet.
- 2007 Annual Air Compliance Certification dated April 15, 2008.
- EPA RMP*Submit document, dated May 23, 2008.
- Mill Creek Station Process Safety Management Program and Risk Management Plan Elements, dated April 28, 2008.
- Mill Creek Generating Station Title V Renewal Application document, dated November 29, 2007.
- November 1, 2002 (effective date) KPDES Permit (Permit No. KY0003221) issued by KDEP (as modified July 1, 2004).
- Monthly Discharge Monitoring Reports for calendar year 2007.
- May 14, 2007 KPDES Permit Renewal Application.
- 2007 Groundwater Protection Plan.
- Semiannual Groundwater Monitoring Reports for calendar year 2007.
- September 2006 Modification - KDEP Solid Waste Permit Summary (Permit No. 056-00029).

- October 2006 Best Management Practices and SPCC Plan.
- TRI Spreadsheet for 2007.
- Tier Two Emergency and Hazardous Chemical Inventory Report for 2007.
- 2007 Hazardous Waste Annual Report Form 1.
- 2008-2012 Operating Plan (January 7, 2008).

Black & Veatch also obtained a recent summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.

B.1.2.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at Mill Creek Station.

B.1.2.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this documentation review was an attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.1.2.2.1 Air Program Compliance. The Mill Creek Station's air permit is a combined PSD and Part 70 Title V operating permit (Permit No. 145-97-TV) that was issued to Louisville Gas & Electric Company on June 1, 2003. The combined PSD/Part 70 operating permit is in effect for 5 years from the effective date. A renewal application must be submitted at least 180 days (6 months) prior to the expiration of the permit (June 1, 2008), which made a renewal application due to the Air Pollution Control District of Jefferson County no later than December 1, 2007. It should be noted that the term for the Acid Rain permit (included in the combined permit) for Mill Creek is coincident with the term of the Operating Permit and expired on June 1, 2008.

The following items are findings from the document review:

- The current air construction and operating permit (Permit No. 145-97-TV) expired on June 1, 2008. EON has indicated that it submitted a renewal application dated November 29, 2007. This document was provided to Black & Veatch for review. In the interim, the facility is able to operate under a permit shield under the conditions of the aforementioned permit.
- EON has submitted a 2007 Annual Air Compliance Certification indicating that they were in intermittent compliance with their permit conditions. The report indicates that Method 5 stack tests were performed on units but testing reports were not submitted within the required period. In addition, monitoring of opacity and particulate matter resulted in deviations of operating parameters due to instrumentation or operational problems, but did not result in emission standard exceedances. For the intermittent compliance of the noted opacity and particulate matter, the report indicates these items were previously reported to the Agency in either semiannual reports or the quarterly Title V monitoring summary reports. However, these reports were not provided to Black & Veatch for review.
- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

B.1.2.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is based on known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs, no attempt in determining how these changes will affect this facility will be made. However, based on a review of the Mill Creek Station's documentation, the following identified items were noted, since they have the potential to affect future operations plans for the facility:

- In 2006, E.ON determined that the Mill Creek Station Units 1-4 were Best Available Retrofit Units (BART) eligible units. Following the BART guidance and conducting analyses focusing only on particulate due to the Clean Air Interstate Rule (CAIR) rule satisfying requirements for NO_x and SO_2, E.ON submitted a report in July 2007 to KDAQ, which demonstrated that the Mill Creek Station units were subject to BART requirements. The

Mill Creek Station facility was determined to be BART applicable and required a full BART engineering and modeling evaluation. Therefore, E.ON conducted an evaluation for primary and secondary particulate (such as SO_3) controls on Mill Creek Units 1-4. LG&E submitted the full Mill Creek Station BART evaluation to the KDAQ in September of 2007. EON indicated in email correspondence dated July 11, 2008, that KDAQ accepted the BART determination for this facility. However, it should be noted that since this determination, the CAIR has been vacated. Therefore, the aforementioned determination may no longer be valid. Additional information is contained in Section 4.0 on this issue.

- Based on information obtained verbally during the site visits in July 11 and 14, 2008, plant personnel indicated that abatement of SO_3 emissions is necessary on Unit 3 & 4 to mitigate the observable plume issues that are exacerbated by the operation of SCR systems on these units. Additionally, installation of SO_3 controls consisting of hydrated lime was the conclusion of the aforementioned BART determination. Installation of this control technology is planned for 2011. This installation will likely require a permit action or regulatory approval. No information regarding the applicability determination or other permit activity on this issue was available for review. However, when notified of this issue, EON indicated that it will obtain the necessary approvals prior to starting the project.
- The Mill Creek Station Operating Plan indicated investigation and/or planning for turbine overhauls, major equipment overhauls, and major boiler component replacements, which could include unit reheater and superheater replacements. The work on the individual units' reheaters and superheaters has been scheduled to occur during outage periods between 2007 and 2012. These maintenance issues, as well as the equipment overhauls, are a potential concern due to the fact that these types of modifications can debottleneck electric generating units and allow for an increased utilization of the boiler (i.e., unit could operate more hours and/or potentially emit more pollutants than it has done previously) and other emission sources. Depending on the activity, a permit action and/or regulatory approval may be required or, at a minimum, a regulatory determination that the activity is not a modification requiring a permit action. No information regarding the applicability determination or other permit activity on these issues was available for review.

B.1.2.3 Water.

B.1.2.3.1 Water Supply. Water supply for cooling water at Mill Creek Station is from the Ohio River. According to the SPCC plan, three onsite groundwater supply wells were installed but are not used. Drinking water is supplied by a municipal supplier.

B.1.2.3.2 Water Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. The EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

Mill Creek Station has a KPDES wastewater discharge permit (Permit No. KY0003221) issued by KDEP in 2002 (as modified July 1, 2004). The permit expired on October 31, 2007. EON submitted a timely renewal application in May 2007. A letter from KDEP on May 21, 2007 acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. Mill Creek Station continues to operate under the terms of the 2002 permit until permit renewal is processed by KDEP. (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical).

The 2002 permit includes limits for such wastewater discharges as once-through cooling water, cooling tower blowdown, ATB discharge, and storm water runoff. Limits appear to be typical for large power generation facilities. The permit requires monitoring and reporting of parameters such as temperature, flow, selected metals, residual chlorine, and annual reporting of whole effluent toxicity and priority pollutants (by analysis or engineering calculations).

Black & Veatch reviewed discharge monitoring reports for calendar year 2007 and the results of 2007 toxicity testing (reported in a letter from Microbac Laboratories on October 15, 2007). No issues of noncompliance were noted.

According to the EPA ECHO database, the facility was inspected in 2005 and no alleged violations are recorded in the database from wastewater discharge inspections and reports.

Mill Creek Station does not have onsite sanitary sewage disposal. Sanitary sewage is sent offsite. Runoff from the coal pile area is collected and pumped to the ATB.

B.1.2.4 Solid and Hazardous Waste. Mill Creek Station produces combustion byproducts such as fly ash, general refuse trash, and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.2.4.1 Combustion/Coal Byproducts. Mill Creek Station generates bottom ash, fly ash, boiler slag, and FGD solid byproducts (gypsum). If not marketed or beneficially used, the bottom ash and fly ash is placed in an onsite surface impoundment ATB or placed in an onsite landfill. EON operates the landfill under a KDEP Solid Waste Disposal Facility Permit (Permit Number 056-00029) modified in 2006. For landfills, the only requirement for recordkeeping is the groundwater monitoring data that complies with the Groundwater Monitoring Plans. The construction plans for the sites are not reported on and are generally only reviewed during inspections, which typically only occur during expansion application processes. The state inspectors have not left any inspection reports on the permits for Mill Creek Station. For ash ponds which are permit-by-rule and not permitted under special waste permitting, the only monitoring are the requirements from the KPDES permits.

Black & Veatch reviewed copies of the semiannual groundwater monitoring reports for calendar year 2007. The final report for 2007 notes that, to date, the monitoring activities have indicated only minimal impacts from the landfill on human health and the environment. No waste compliance issues were noted.

Nearly all of the FGD byproduct gypsum produced is shipped by barge to a wallboard manufacturer. Unmarketed gypsum is landfilled onsite.

B.1.2.4.2 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance at Mill Creek Station (including office waste, maintenance waste, and other nonhazardous waste) is stored onsite in dumpsters before being transferred to a licensed commercial landfill.

B.1.2.4.3 Hazardous Waste. The Mill Creek Station facility is a small quantity generator of hazardous waste (defined in federal and Kentucky regulations as 220-2200 pounds generated in any 1 calendar month) (401 KAR 32 [Standards Applicable to Generators of Hazardous Waste]). The facility filed a 2007 Hazardous Waste Annual Report Form 1 confirming its continuing status as a small quantity generator. No hazardous waste compliance issues were noted in documents reviewed. According to the EPA ECHO database, KDEP conducted a hazardous waste inspection in September 2007 and found no violations or compliance issues.

B.1.2.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines, and including process oil use in the SPCC plan. EPA has amended the SPCC requirements of the Oil Pollution Prevention regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[2] on SPCC plans require that existing facilities operating prior to August 16, 2002 amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Mill Creek Station has a Best Management Practices and SPCC plan dated October 2006. This SPCC plan responds to EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. Mill Creek Station handles thousands of gallons of oil products including fuel oil and a variety of transformer oil and lubricants. The largest oil tank in the SPCC plan is a 10,000 gallon diesel fuel tank.

The Mill Creek Station SPCC plan describes compliance with EPA regulations effective in 2009. Black & Veatch agrees with the general introductory statements in the plan that the plan "serves to fulfill the regulatory requirements" and addresses the new 2002 requirements. Information provided indicates that no major additional actions and expenses appear to be necessary for oil compliance.

B.1.2.6 Emergency Planning. The Mill Creek Station uses anhydrous ammonia in the SCR systems to reduce NO_x emissions. Based on the use and quantity of ammonia stored, the process is subject to specific environmental regulations under Section 112(r) of the Clean Air Act administered by the EPA for chemical accident prevention. Specifically, the RMP provisions (published June 20, 1996) are found in 40 CFR Part 68. Additionally, the plant is also subject to the Occupational Safety and Health Administration (OSHA) regulations 29 CFR 1910.119 for Process Safety Management. These two regulations address the safe use and handling of hazardous chemicals. In

[2] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

December 2006, EON completed a self-audit of these programs as required by the aforementioned programs. The results of the audit indicated that there were no significant deficiencies and that recordkeeping formed the majority of the findings.

A 2008 version of Mill Creek Process Safety Management Program and Risk Management Plan Elements document was reviewed.

Black & Veatch reviewed an inventory of chemicals used onsite as detailed in the 2007 Groundwater Protection Plan and in the 2007 TRI spreadsheet provided by EON. Section 313 of the EPCRA requires certain facilities to submit an annual TRI report to the EPA. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities and to allow better response should a chemical release occur.

According to the TRI spreadsheet, the type and amounts of listed toxic materials released to the environment (primarily byproducts of coal combustion) by annual operations at Mill Creek Station appear to be typical for large coal power plants. EON provided a receipt from EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

Under OSHA (29 CFR 1910 [Occupational Safety and Health Standards]) and EPA (40 CFR 372 [Toxic Chemical Release Reporting: Community Right-to-Know] regulations), facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year. Black &Veatch reviewed the 2007 Tier II report for Mill Creek and found the list to be typical for large coal power plants. The Mill Creek Station Tier II 2007 report was submitted to the Pleasure Ridge Park Fire Department with a postal return receipt attached.

Historically, according to the EPA ECHO database, the Mill Creek Station facility paid an EPCRA penalty of $19,500 in 2005. Information provided by EON indicated that EON had not reported anhydrous ammonia in the Mill Creek TRI report for calendar year 2003. The amount of ammonia onsite was above the reporting threshold. EON resolved this issue in subsequent TRI reporting in 2006 and 2007.

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of this information.

B.1.2.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.1.2.8 Other Environmental Issues. Past and potential neighborhood nuisance problems were mentioned in the Mill Creek Station 2008 to 2012 Operating Plan

(January 7, 2008). A past problem with "rusty flake fallout" in the neighborhood was resolved with the addition of a wet stack conversion according to EON. According to the operating plan, plant management is concerned about the possibility of ammonia odor issues in the neighborhood and held an open house in 2004 to improve awareness and community relations.

Observations from the document review indicated a generally high level of environmental awareness in current and recent operations of the Mill Creek Station facility and a proactive approach to environmental management at the facility. Professional environmental staff located at both the facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning. EON provided independent audit information demonstrating procedures for checking fine-point compliance with environmental requirements.

Documents provided by EON did not include studies of any preexisting environmental conditions at the Mill Creek Station site (prior to current operations) or any investigations of known soil/groundwater contamination issues from past operations including prior ash/sludge landfills/basins, from prior and ongoing management of coal and limestone onsite, and from any historical spills or other previous releases at the site. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.1.3 Cane Run Generating Station Environmental Review
Permit Status & Regulatory Compliance
Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of this environmental section did not visit the site. Key documents provided by EON for this review included the following:

- October 30, 2002 (issuance date) Jefferson County Air Quality Permit/Title V Operating Permit (Permit No. 145-97-TV, R1)
- 2007 Emissions Inventory Spreadsheet.
- 2007 Annual Air Compliance Certification dated April 15, 2008.
- BART Exemption Modeling for E.W. Brown Station, Ghent Station, Cane Run Station, and Mill Creek Station Facilities, dated July 2007.
- EON email correspondence regarding KDAQ BART determination dated July 11, 2008.
- Cane Run Generating Station Title V Renewal Application document, dated April 27, 2007
- November 1, 2002 (effective date) Kentucky Pollutant Discharge Elimination System (KPDES) Permit (Permit No. KY0002062) issued by KDEP (as modified July 1, 2004).
- Monthly Discharge Monitoring Reports for calendar year 2007.
- May 14, 2007 KPDES Permit Renewal Application.
- 2007 Groundwater Protection Plan.
- Groundwater Monitoring Plan, December 2001 revision.
- Semiannual Groundwater Monitoring Reports for calendar year 2007.
- July 2003 Modification KDEP Solid Waste Disposal Facility Permit (Permit Number 056-00030).
- May 2006 Best Management Practices and SPCC Plan.
- TRI Spreadsheet for 2007.
- Tier Two Emergency and Hazardous Chemical Inventory Report for 2007.
- 2007 Hazardous Waste Annual Report Form 1.
- Selected correspondence with regulatory agencies including February 16, 2006 Notice of Violation from KDEP, and other letters as cited in this report.
- Cane Run Environmental Compliance Manual – January 2008.
- 2008-2012 Facility Operating Plan (revised December 2007).

Black & Veatch also obtained a summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.

B.1.3.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at Cane Run Station as summarized in the Cane Run Station Environmental Compliance Manual.

B.1.3.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this cursory documentation review was to attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.1.3.2.1 Air Program Compliance. The Cane Run Station's air permit is a combined PSD and Part 70 Title V operating permit (Permit No. 175-00-TV, Revision 1) that was issued to Louisville Gas & Electric Company on October 30, 2002. The combined PSD/Part 70 operating permit is in effect for 5 years from the effective date. A renewal application must be submitted at least 180 days prior to the expiration of the permit (October 30, 2007) making a renewal application due to the Air Pollution Control District of Jefferson County no later than April 30, 2007. The term for the Acid Rain permit (included in the combined permit) is coincident with the term of the Operating Permit and expired on October 30, 2007.

The following are findings from the document review:

- The current air construction and operating permit (permit No. 175-00-TV) expired on October 30, 2007. EON submitted a renewal application dated April 27, 2007. In the interim, the operating permit does allow the owner or operator to continue to operate in accordance with the terms and conditions of this permit beyond the expiration date under a permit shield.
- EON has submitted a 2007 Annual Air Compliance Certification indicating that they were in intermittent compliance with their permit

conditions. The report indicates that several units deviated from their permit requirements. These deviations included the following issues:

- Method 5 stack tests were performed on units, but testing reports were not submitted within the required period.
- SO_2 excess emissions and reporting.
- Opacity standard and conducting Method 9 tests.
- Compliance with reporting requirements.

The report indicates these intermittent compliance issues were previously reported to the Agency in semiannual reports or the quarterly Title V monitoring summary reports, quarterly excess emission reports, or upset condition reports. However, these reports were not provided to Black & Veatch for review.

- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

B.1.3.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is based on known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs, no attempt in determining how these changes will affect this facility will be made. However, based on a review of the Cane Run Station's documentation, the following identified items were noted because they have the potential to affect future operations plans for the facility:

- In 2006, E.ON determined that the Cane Run Station – CR5 and CR6 - were BART-eligible units. Following the BART guidance and conducting analyses focusing only on particulate due to the CAIR rule satisfying BART requirements for NO_x and SO_2, E.ON submitted a report in July 2007 to KDAQ which demonstrated that the Cane Run BART-eligible units were exempt from BART requirements. EON indicated in email correspondence dated July 11, 2008 that KDAQ accepted the BART determination for this facility that CR5 and CR6 were exempt. However, it should be noted that since this determination, the CAIR rule has been vacated. Therefore, the aforementioned determination may no longer be valid. Additional information is contained in Section 4.0 on this issue.

- The Cane Run Station Operating Plan indicated investigation and/or planning for major boiler component replacements, which could include unit economizers, burner fuel and air tip replacements, boiler tubes and surface replacements. The operating plan indicated that work on the individual units has either already taken place, is being reviewed, or has been scheduled to occur in the future. These maintenance issues, as well as the equipment replacements, are a potential concern due to the fact that these types of changes can be viewed as modifications and can allow for an increased utilization of the boiler (i.e., unit could operate more hours and/or potentially emit more pollutants than it has done previously). Depending on the activity, a permit action and/or regulatory approval may be required. At a minimum, a regulatory determination that the activity is not a modification requiring a permit action must be obtained. No additional information regarding these activities or associated air permit determinations or permit actions was available for review.

B.1.3.3 Water.

B.1.3.3.1 Water Supply. Water supply for cooling water at Cane Run Station is from the Ohio River. Drinking water is supplied by a municipal system. According to the SPCC plan, two onsite groundwater supply wells were installed but are not used.

B.1.3.3.2 Water Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

Cane Run Station has a KPDES wastewater discharge permit (Permit. No. KY0002062) issued by KDEP in 2002 (as modified July 1, 2004). The permit expired on October 31, 2007. EON submitted a timely renewal application in May 2007. A letter from KDEP on May 21, 2007 acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. Cane Run Station continues to operate under the terms of the 2002 permit until the permit renewal is processed by KDEP. (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical.)

The 2002 KPDES permit includes limits for such wastewater discharges as once-through cooling water, ATB discharge, and storm water runoff. Limits appear to be typical for large power generation facilities. The permit requires monitoring and/or reporting of parameters such as temperature, flow, selected metals, residual chlorine, and annual reporting of whole effluent toxicity.

Black & Veatch reviewed discharge monitoring reports for calendar year 2007 and the results of 2007 toxicity testing (reported in a letter from Microbac Laboratories on May 30, 2007). No issues of noncompliance were noted.

EON provided a copy of a Notice of Violation (NOV) issued in February 2007 by KDEP for an exceedance of the permit allowable discharge concentration of oil and grease. In November 2006, the oil and grease daily value was 21 mg/l in one sample, and the average monthly value was 11 mg/l. The permit establishes both a daily maximum monthly value and a maximum monthly average of 9 mg/l. According to a February 21, 2007 internal EON email, this exceedance appeared to be a one-time occurrence without a known reason. (Black & Veatch notes that infrequent exceedances of a permit limit may be a typical expectation for an industrial facility due to such events as operational variations or laboratory problems. However, the state agency may issue an NOV for any permit exceedance.)

According to the EPA ECHO database, the Cane Run Station was inspected in 2005. The only alleged violation recorded in the data base from wastewater discharge inspections and reporting is the 2006 oil and grease exceedance associated with the NOV identified above.

B.1.3.4 Solid and Hazardous Waste. Cane Run Station produces combustion byproducts such as fly ash, general refuse trash, and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.3.4.1 Combustion/Coal Byproducts. Cane Run Station generates bottom ash, fly ash, and FGD sludge. Fly ash is accumulated and reused. The bottom ash is periodically sluiced to the ash pond. The FGD sludge is treated with lime and fly ash to make a cement-like mixture, which is managed onsite by landfilling. EON operates the landfill under a KDEP Solid Waste Disposal Facility Permit (Permit No. 056-00030) modified in 2003. For landfills, the only requirements for recordkeeping are the groundwater monitoring data that complies with the Groundwater Monitoring Plans. The construction plans for the sites are not reported on and are generally only reviewed during inspections, which typically only occur during expansion application processes. No compliance issues were identified by the state inspectors for the Cane Run Station. For ash ponds, which are permit-by-rule and not permitted under special waste permitting, only monitoring are the requirements from the KPDES permits.

Black & Veatch reviewed copies of the CR Groundwater Monitoring Plan and the semiannual groundwater monitoring reports for calendar year 2007. The final report for 2007 notes that, to date, the monitoring activities have indicated only minimal impacts from the landfill on human health and the environment. No waste compliance issues were noted.

As observed during the site visit by Black & Veatch, adequate long-term options for disposal and storage of combustion products is an important consideration for Cane Run Station. The bottom ash pond has 1 to 2 years remaining capacity, and the landfill for disposal of FGD byproduct and fly ash has 4 to 5 years capacity. While plans to alleviate this problem are being developed through the potential permitting of additional specific onsite disposal sites, these plans are not finalized and can be subject to regulatory and public scrutiny. Cane Run Station is trying to find beneficial use opportunities for the combustion products to help alleviate the issue.

B.1.3.4.2 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance at Cane Run Station (including office waste, maintenance waste, and other nonhazardous waste) is stored onsite in trash compactors and dumpsters before being transferred to a licensed commercial landfill.

B.1.3.4.3 Hazardous Waste. The Cane Run Station facility is a small quantity generator of hazardous waste defined in Kentucky regulations (401 KAR 32 - Standards Applicable to Generators of Hazardous Waste) as 220-2200 pounds generated in any calendar month. The facility filed a 2007 Hazardous Waste Annual Report Form 1 confirming its continuing status as a small quantity generator. According to the EPA ECHO database, KDEP conducted a hazardous waste inspection in April 2008.

On April 21, 2008, the Kentucky Division of Waste Management (Division) issued a Letter of Warning (LOW) to LG&E regarding some universal waste that had been observed on site during an agency inspection on April 14, 2008. During a field inspection follow up, the agency verified through a review of the LG&E internal tracking log that Cane Run Station had complied with the LOW and had shipped the waste to another facility for accumulation. In addition, the facility's self inspection log was amended to include the details required to ensure compliance with the accumulation requirements for conditionally exempt small quantity hazardous waste generators. The April 21, 2008 letter stated that the actions taken by LG&E in response to the LOW are considered sufficient with regard to the violations and that the Division does not intend to pursue the LOW through the Division of Enforcement or via legal proceedings.

No other hazardous waste compliance issues were noted in the documents provided for review.

B.1.3.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines, and including process oil use in the SPCC plan. EPA has amended the SPCC requirements of the Oil Pollution Prevention regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[3] on SPCC plans require that existing facilities operating prior to August 16, 2002 amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Cane Run Station has a Best Management Practices and Spill Prevention, Control and Countermeasures Plan dated May 2006. This SPCC plan responds to EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. Cane Run Station handles thousands of gallons of oil products including fuel oil and a variety of transformer oil and lubricants. The largest oil tank in the SPCC plan is a 100,000 gallon fuel oil tank.

The Cane Run Station SPCC plan describes compliance with EPA regulations effective in 2009. Black & Veatch agrees with the general introductory statements in the plan that the plan "serves to fulfill the regulatory requirements" and addresses the new 2002 requirements.

Information obtained by Black & Veatch during the site visit at Cane Run Station indicated that previously used underground storage tanks for fuel oil (six 7,000 gallon tanks, two 12,000 gallon tanks, and one tank less than 1000 gallons) had been emptied of fuel and were permanently closed in place by filling with flowable fill–low strength concrete.

[3] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

Otherwise, information provided indicates that no major additional actions and expenses appear to be necessary for oil compliance.

B.1.3.6 Emergency Planning. Black & Veatch reviewed an inventory of chemicals used onsite as detailed in the 2007 Groundwater Protection Plan and in the 2007 TRI spreadsheet provided by EON. Section 313 of the EPCRA requires certain facilities to submit an annual TRI Report to the EPA. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities and to allow better response should a chemical release occur. EON provided a receipt from the EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

The type and amounts of listed toxic materials released to the environment (primarily byproducts of coal combustion) by annual operations at Cane Run Station according to the TRI spreadsheet appear to be typical for large coal power plants.

Under OSHA and EPA regulations, facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year and make the form available to the public by providing it to state emergency response commissions and the local emergency planning commissions. Black & Veatch reviewed the 2007 Tier II report for Cane Run and found the list to be typical for large coal power plants. The Cane Run Station Tier II 2007 report was submitted to the Pleasure Ridge Park Fire Department with a postal return receipt attached.

Cane Run Station does not store ammonia and is not required to have a RMP under the chemical accident prevention provisions (40 CFR 68).

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of the provided information.

B.1.3.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.1.3.8 Other Environmental Issues. EON provided a copy of the Cane Run Station Environmental Compliance Manual (January 2008 – Revision 14) that described such items as the following:

- Objectives and targets.
- Training, awareness, and competence.
- Document controls and records.
- List of environmental responsibilities.

These items demonstrate the organization of the facility's environmental compliance program.

Black & Veatch's document review indicated a generally high level of environmental awareness in current and recent operations of the Cane Run Station facility and a proactive approach to environmental management at the facility. Professional environmental staff located at both the facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning.

The Cane Run 2008–2012 Operating Plan noted the following information on Page 20:

> "Groundwater monitoring activities continue with the station being involved in an ongoing investigation working with Environmental Affairs and the state environmental agency to study elevated concentrations of contaminants typically associated with coal combustion byproducts. This has involved sampling of groundwater wells located on the site over the last several years. One conclusion based on early data was that the contamination does not pose a significant risk and that corrective action is not needed at this time. In 1999, the State agency required collection and submittal of one full year of data for review. The station collected the data and Environmental Affairs provided it to the agency. No response has been received from the State to date. Potentially, the State could request additional sampling. The Cane Run Station continues to work closely with Environmental Affairs on this issue."

Otherwise, documents provided by EON did not include studies of any preexisting environmental conditions at the Cane Run Station site (prior to current operations) or additional investigations of known soil/groundwater contamination issues from past operations including prior ash/sludge landfills/basins, from prior and ongoing management of coal and limestone onsite, and from any historical spills or other previous releases at the site. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.1.4 Ghent Generating Station Environmental Review

Permit Status and Regulatory Compliance

Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of this environmental section did not visit the site. Key documents provided by EON for this review included the following:

- 2007 Annual Air Compliance Certification dated January 28, 2008.
- October 31, 2007 (issuance date) KDAQ Air Quality Permit (Permit No. V-05-043, Revision 1).
- 2007 Emissions Inventory Spreadsheet.
- EON internal correspondence from November 2007 indicating EPA concern with sulfur acid mist (SAM) emissions triggering new source review (NSR).
- EPA letter for opacity NOV dated September 26, 2007.
- KDAQ-Full Compliance Evaluation report dated December 21, 2007.
- External Environmental Compliance audit by Audit Services dated November 20, 2003.
- External Environmental Compliance audit by Audit Services dated February 13, 2008.
- External Process Safety Management and Risk Management Planning audit by Audit Services dated November 20, 2003.
- BART Exemption Modeling for E.W. Brown Station, Ghent Station, Cane Run Station, and Mill Creek Station Facilities, dated July 2007.
- EON email correspondence regarding KDAQ BART determination, dated July 11, 2008.
- Submittal letter and application to the KDAQ requesting to install three wet flue gas desulfurization (WFGD) units and ancillary equipment, dated January 13, 2005.
- KDAQ determination of a complete application for a minor permit revision for the WFGD units, dated February 15, 2005.
- Application submittal letter to the KDAQ requesting to install two SO_3 mitigation systems on Units 3 and 4, dated November 1, 2007.
- KDAQ determination of no permit required for the installation of two SO_3 mitigation systems on Units 3 and 4, dated November 5, 2007.

- July 1, 2002 (effective date) Kentucky Pollutant Discharge Elimination System (KPDES) Permit (Permit. No. KY0002038) issued by KDEP (as modified July 1, 2004).
- Discharge Monitoring Reports for calendar year 2007.
- December 28, 2006 KPDES Permit Renewal Application.
- 2007 Groundwater Protection Plan.
- July 2003 Best Management Practices and SPCC Plan.
- TRI Spreadsheet for 2007.
- Tier Two Emergency and Hazardous Chemical Inventory Report for 2007.
- 2004 Risk Management Plan.
- Selected correspondence with regulatory agencies including a March 2005 and a May 2008 Inspection Report letter from KDEP, and other letters as cited in this report.
- 2008-2012 Ghent Station Operating Plan (undated).

Black & Veatch also obtained a recent summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.

B.1.4.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at the Ghent Station.

B.1.4.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this documentation review was to attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.1.4.2.1 Air Program Compliance. The Ghent Station's air permit is a combined PSD and Part 70 Title V operating permit (Permit No. V-05-043, Revision 1) that was issued to Kentucky Utilities Company on October 31, 2007. The combined PSD/Part 70 operating permit is in effect for 5 years from the effective date. It should be noted that the term for the Acid Rain permit (included in the combined permit) for the Ghent Station is coincident with the term of the Operating Permit and expires on October 31, 2012.

The following identified items are findings from the document review:

- EON correspondence from November 2007 indicated that the EPA is interested in the increase in Sulfuric Acid Mist (SAM) emissions and thereby the potential to trigger NSR PSD requirements due to the previous installation of the SCR systems on GH1, GH3, and GH4. While correspondence indicates that the installations were made under the authority of an approval letter from KDAQ and during the time period when Pollution Control Projects (PCP) were still allowed under EPA rule, there has been no resolution to the issue of EPA's inquiry.
- Similar to the above issue, company planning documents indicate several air pollution control projects have either recently been completed or are in planning stages (including new stacks, WFGD systems, SO_3 mitigation systems, and an SCR system). An application submittal and approval letter from the KDAQ for the SO_3 mitigation systems was available for review. Additionally, a submittal letter for the WFGD application (without supporting information) and an approval letter from the KDAQ from January and February 2005, respectively, were available for review. The approval letter from the KDAQ indicated that the minor permit modification for the project was classified as "environmentally beneficial" or otherwise known as a PCP. However, no additional information was found indicating that these changes at Ghent Station underwent the necessary permitting review and met the applicable requirements in light of the vacature of the NSR PCP exemption on June 24, 2005. This would also include current or anticipated changes in material handling (fuel and byproduct) due to the addition of the FGD system. However, when notified of this issue, EON indicated that the KDAQ does not consider the vacature a concern for its FGD projects because the coincidental increases of particulate from the associated material handling systems were included in the application and were less than the applicable significance level.
- A NOV was issued by the EPA on September 26, 2007, for opacity violations based on EPA Method 9 observations on June 20, 2007. The 2007 Annual Compliance Certification indicates that EON met with EPA on November 20, 2007, and that they are currently awaiting EPA response.

- EON has submitted a 2007 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions (and other regulatory programs such as Acid Rain and Risk Management Planning) with the exception of a few items. These items are noted below in greater detail:
  - GH1 was in continuous compliance except for 2 hours of PM exceedances and the September 26, 2007, NOV for opacity.
  - GH2 was in continuous compliance except for opacity exceedances less than 0.5 percent of operating time and five SO_2 exceedances.
  - GH3 was in continuous compliance except for opacity exceedances, which totaled 1.08 percent and 2 hours of PM exceedances.
  - GH4 was in continuous compliance except for opacity exceedances, which totaled 1.08 percent and 2 hours of SO_2 exceedances.
  - The opacity exceedances were mainly due to start-ups, shut-downs, load changes, blowing, precipitator trouble, and unit trip/upset. The SO_2 exceedances were due to fuel problems.
- The KDAQ performed an onsite tour/inspection of the facility in 2007 and documented the results in a report titled DAQ-Full Compliance Evaluation dated December 21, 2007. The official overall compliance status is listed as "Out of Comp.–Viol documented." The inspection report noted numerous opacity violations such as the following:
  - GH2 experienced 249 6-minute opacity violations between January 1, 2007 and September 30, 2007, and relief was granted for 180 of them.
  - Stack 3/4 experienced 119 6-minute opacity violations between January 1, 2007 and March 31, 2007, and relief was granted for 28 of them on GH3.
  - There is no mention of what is to become of the items for which no relief is granted.
- In 2003, EON commissioned an external Environmental Compliance audit by Audit Services with the purpose of reviewing the facility's compliance with federal, state, and local environmental regulations and corporate policies and procedures. The conclusion was that the facility maintained compliance within the sampling depth of the audit and commended the facility's Environmental Compliance Reference Manual. It also indicated

that the facility had no NOVs within the past 5 years of the report date (2003).

- In 2007 (report date February 13, 2008), EON commissioned an external Environmental Compliance audit by Audit Services with the purpose of reviewing the facility's compliance with federal, state, and local environmental regulations and corporate policies and procedures. The conclusion was that the facility maintained general compliance with required regulations.
- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

B.1.4.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is based on known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs, no attempt in determining how these changes will affect this facility will be made in this report. However, based on a review of the Ghent Station's documentation, the following items were noted because they have the potential to affect future operations plans for the facility:

- In 2006, E.ON determined that the Ghent Stations – GH1 and GH2 - were BART-eligible units. Following the BART guidance and conducting analyses focusing only on particulate due to the CAIR rule satisfying BART requirements for NO_x and SO_2, E.ON submitted a report in July 2007 to KDAQ which demonstrated that the Ghent Station BART-eligible units were exempt from BART requirements. EON indicated in email correspondence dated July 11, 2008, that KDAQ accepted the BART determination for this facility that Units 1 and 2 were exempt. However, it should be noted that since this determination, the CAIR rule has been vacated. Therefore, the aforementioned determination may no longer be valid. Additional information on this issue is contained in Section 4.0 of this report.

B.1.4.3 Water.

B.1.4.3.1 Water Supply. Water supply for cooling water at Ghent Station is from the Ohio River. Drinking water is supplied by Carroll County Water District No. 1. Five onsite groundwater supply wells provide make-up water for deionizers.

B.1.4.3.2 Water Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

Ghent Station has a KPDES wastewater discharge permit (Permit. No. KY0002038) effective July 2002 (as modified July 1, 2004). The permit expired on June 30, 2007. EON submitted a timely renewal application in December 2006 and a letter from KDEP on January 29, 2007 acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. Ghent Station continues to operate under the terms of the 2002 permit until permit renewal is processed by KDEP. (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical.)

The 2002 permit includes limits for such wastewater discharges as once-through cooling water, cooling tower blowdown, ash pond overflow, and storm water runoff. Limits appear in general to be typical for large power generation facilities. The permit requires reporting or monitoring of such parameters as temperature, flow, selected metals, residual chlorine, and annual reporting of whole effluent toxicity and priority pollutants (by analysis or engineering calculations).

Black & Veatch reviewed discharge monitoring reports for calendar year 2007 and the results of 2007 toxicity testing (reported in a letter from Microbac Laboratories on October 3, 2007). No issues of noncompliance were noted.

An inspection report from a March 2005 KDEP visit noted that the facility appeared to be operating in compliance with all discharge permit requirements. According to the EPA ECHO database, the facility was also inspected in 2007 and no alleged violations are recorded in the data base from wastewater discharge inspections and reports.

Further documents related to compliance provided by EON included the following:

- A January 3, 2003, Notice of Exception for total residual chlorine of 0.34 mg/l compared to a permit allowed minimum of 0.50 mg/l.
- A July 7, 2006, Release Report and email of notice provided to the state of an estimated 2,300 gallon release of treated wastewater into a storm sewer instead of to the ash pond.
- A March 9, 2007, Incident Closure letter from KDEP acknowledging that a September 5, 2007, release of coal-fine bearing storm water did not violate regulations.

Black & Veatch is not aware of any documentation regarding resolution of these issues or any consequent concerns associated with these apparent isolated incidents. (Black & Veatch notes that infrequent exceedances of a permit level may be a typical expectation for an industrial facility due to such events as operational variations or laboratory problems. However, the state agency may issue an NOV for any permit exceedance.)

B.1.4.4 Solid and Hazardous Waste. Ghent Station produces combustion byproducts such as fly ash, general refuse trash, and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.4.4.1 Combustion/Coal Byproducts. Ghent Station manages bottom ash, fly ash, pyrites (from the coal), and FGD scrubber waste in onsite storage basins and landfills. The bottom ash, pyrites, and fly ash are sluiced to ATB No. 2, which has a projected life (depending on production rates and usage opportunities) of about 5 years until 2013. ATB No. 1 is near full capacity with bottom ash, fly ash, and pyrites.

FGD sludge is oxidized to calcium sulfate/synthetic gypsum and a portion is dewatered and hauled offsite for use at a nearby wallboard factory. The excess gypsum, including the increased amount from operation of additional FGD systems (coming online in the next 2 years), will be stored in the gypsum stacks with an estimated stack life of 5 to 7 years. EON is pursuing additional offsite markets for gypsum.

In a December 11, 2003 letter, KDEP Division of Water approved a vertical expansion to ATB No. 2 and the impoundment of water at the expanded facility. For basins that are under the 401 KAR 45:060 Kentucky special waste permit-by-rule, the only monitoring requirements are the requirements from the KPDES permits.

As observed during the site visit by Black & Veatch, adequate long-term options for disposal and storage of combustion products is one of the most critical issues for the Ghent Station at present. The need for additional product disposal/storage is acute. A study has been performed and a plan is presently being finalized to construct a new ash pond, landfills, or a combination, to provide another 25 years of storage. According to EON, the decision as to which plan to implement will be made in the near future.

B.1.4.4.2 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance at the Ghent Station (including office waste, maintenance waste, and other nonhazardous waste) is stored onsite in dumpsters before being transferred to a licensed commercial landfill.

B.1.4.4.3 Hazardous Waste. The Ghent Station is a small quantity generator of hazardous waste (defined in Kentucky hazardous waste regulations [401 KAR 30] as 220-2200 pounds generated in any calendar month). The facility filed a 2007 Hazardous Waste Annual Report Form 1 confirming its continuing status as a small quantity generator. No hazardous waste compliance issues were noted in documents reviewed. KDEP conducted a hazardous waste inspection in April 2008 and found no violations or compliance issues, other than minor issues that were resolved during the inspection to the satisfaction of the inspectors.

B.1.4.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines, and including process oil use in the SPCC plan. EPA has amended the SPCC requirements of the Oil Pollution Prevention regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[4] on SPCC plans require that existing facilities operating prior to August 16, 2002, amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Ghent Station has a Best Management Practices and Spill Prevention Control and Countermeasures Plan dated July 2003. This SPCC plan responds to the EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. Ghent Station handles thousands of gallons of oil products including fuels and a variety of transformer oil and lubricants. The largest oil tanks identified in the SPCC plan are 535,000 gallon, 100,000 gallon, and 20,000 gallon fuel oil tanks.

The facility is scheduled to complete oil containment improvements associated with the SPCC plan and the EPA regulations by 2009. The facility plans to move all pipelines above ground by 2009. Otherwise, information provided indicates that no major additional actions and expenses appear to be necessary for oil compliance.

No underground storage tanks remain at Ghent – a 10,000 gallon underground storage tank was permanently closed in 2004 and KDEP sent a letter of no further action required on February 15, 2005.

EON also provided Incident Closure letters from KDEP (dated June 5, 2008; June 4, 2008; February 18, 2008; and January 3, 2008) noting that apparently isolated minor releases reported to the state did not violate regulations. Such letters tend to indicate that the Ghent Station staff have an active program to minimize releases and take appropriate actions to maintain compliance with spill prevention requirements.

B.1.4.6 Emergency Planning. Ghent Station has in place an RMP under federal chemical accident prevention provisions (40 CFR 68). The Ghent Station RMP is associated with safe ammonia storage and use on site. EON plans to update the RMP in 2009. EON provided a copy of an internal audit of Ghent Station Safety Management and Risk Management Planning dated August 3, 2007. This document described plans to address any issues identified during the audit.

Black & Veatch reviewed an inventory of chemicals used onsite as detailed in the Groundwater Protection Plan and in the 2007 TRI spreadsheet provided by EON. Section 313 of the EPCRA requires certain facilities to submit an annual TRI Report to the EPA. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities and to allow better response should a chemical release occur.

[4] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

According to the TRI spreadsheet, the type and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at Ghent Station appear to be typical for large coal power plants. EON provided a receipt from EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

Under OSHA and EPA regulations, facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year and must make the form available to the public by submitting it to state emergency response commissions and the local emergency planning commissions. Black & Veatch reviewed the 2007 Tier II report for Ghent Station and found the list to be typical for large coal power plants. The Ghent Station Tier II 2007 report was submitted to the Ghent Fire Department and the Carroll County Emergency Planning Committee with postal return receipts attached.

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of this information.

B.1.4.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.1.4.8 Other Environmental Issues. Observations from the document review indicated a generally high level of environmental awareness in current and recent operations of the Ghent Station and a proactive approach to environmental management at the facility. Professional environmental staff located at both the facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning.

Documents provided by EON did not include studies of any preexisting environmental conditions at the Ghent Station site (prior to current operations) or any investigations of known soil/groundwater contamination issues from past operations including prior ash/sludge landfills/basins, from prior and ongoing management of coal and limestone onsite, and from any historical spills or other previous releases at the site. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.1.5 E.W. Brown Generating Station Environmental Review

Permit Status & Regulatory Compliance

Basis for Review

This environmental review was based on documents provided by EON, and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of the environmental sections did not visit the site. Key documents provided by EON for this review included the following:

- 2007 Annual Air Compliance Certification dated January 28, 2008.
- March 1, 2005 (issuance date) KDAQ Air Quality Permit (Permit No. V-03-034).
- 2007 Emissions Inventory Spreadsheet.
- Various correspondence concerning DAQ letter for NO_x NOV dated November 13, 2007.
- External Environmental Compliance audit by Audit Services dated August 6, 2004.
- BART Exemption Modeling for E.W. Brown Station, Ghent Station, Cane Run Station, and Mill Creek Station Facilities, dated July 2007.
- EON email correspondence regarding KDAQ BART determination, dated July 11, 2008.
- 2008-2010 Operating Plan for E.W. Brown Generating Station (and others) dated January 14, 2008.
- Multi-pollutant Position Report (SO_2, NO_x, Hg, CO_2) dated March 10, 2006.
- Recent summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.
- Submittal letter and application to the KDAQ requesting to install one WFGD unit and ancillary equipment, dated March 1, 2005.
- KDAQ determination of a complete application for a minor permit revision for the WFGD units, dated March 15, 2005.
- KDEP October 24, 2006 Correspondence re: receipt of KPDES permit application.
- KU August 14, 2006 KPDES permit application.
- KDEP KPDES Permit KY0002020, effective February 1, 2002.
- KDEP November 27, 2006 Notice of Violation.
- EON Discharge Monitoring Reports for May 2008.
- EON Discharge Monitoring Reports for 2007.

- EON February 2008 Groundwater Protection Plan.
- KDEP February 8, 2008 Correspondence re: Section 401 WQC.
- KDEP June 27, 2008 Correspondence re: as-built plans for ash pond.
- KDEP December 8, 2007 Stream Construction Permit.
- KHC August 7, 2006 consultation letter.
- COE September 7, 2007 jurisdictional determination letter.
- KDEP August 24, 2006 Stream Construction Permit.
- EON NOI for Storm Water Construction Permit, October 30, 2006.
- EON NOI for Storm Water Construction Permit, June 30, 2006.
- COE July 21, 2006 Nationwide Permit No. 39 authorization.
- EON 2007 Hazardous Waste Annual Report Form 1.
- EON December 13, 2007 spill correspondence.
- EON September 24, 2006 spill correspondence.
- KU Best Management Practices and Spill Prevention, Control, and Countermeasures Plan, April 2008.
- KU Facility Response Plan, April 2008.
- EON SARA Title III Section 312 Report, February 21, 2008.
- EON 2007 TRI Reportable Releases.

B.1.5.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emissions limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and management of chemical materials used onsite.

B.1.5.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this documentation review was to attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.1.5.2.1 Air Program Compliance. The E.W. Brown Generating Station's air permit is a combined PSD and Part 70 Title V operating permit (Permit No. V-03-034) that was issued to Kentucky Utilities Company on March 1, 2005. The combined

PSD/Part 70 operating permit is in effect for 5 years from the effective date. The term for the Acid Rain permit (included in the combined permit) for the E. W. Brown Generating Station is coincident with the term of the Operating Permit and expires on March 1, 2010.

The following are findings from the document review:

- EON was issued two NOVs in 2006 performing "major capital expenditures for Unit 3 at the E.W. Brown Generating Station in order to increase electrical production from the unit to 446 MW." These NOVs surround the fact that the facility failed to obtain the appropriate permits (Prevention of Significant Deterioration and Title V) and follow certain other regulatory programs such as the NSPS prior to executing the changes. The 2008-2012 Operating Plan indicates that EON is currently in NSR proceedings including responding to EPA/Department of Justice requests, settlement negotiations, and discovery. Documentation further indicates that along with other potential new limits on the facility, as part of the settlement, the installation of the SCR on Unit 3 may be moved up from 2015 to 2012. Follow-on correspondence concerning the progress of the NOVs was not available for review.
- Similar to the above issue, company planning documents indicate several major projects, including the installation of a common FGD for BR1, BR2, and BR3, have either recently been completed or are in planning stages. A submittal letter for the WFGD application (without supporting information) and an approval letter from the KDAQ, both dated in March 2005, were available for review. The approval letter from the KDAQ indicated that the minor permit modification for the project was classified as "environmentally beneficial" or otherwise known as a PCP. However, no additional information was found indicating that these changes at E.W. Brown Station underwent the necessary permitting review and met the applicable requirements in light of the vacature of the NSR PCP exemption on June 24, 2005. This would also include current or anticipated changes in material handling (fuel and byproduct) due to the addition of the FGD unit. However, when notified of this issue, EON indicated that the KDAQ does not consider the vacature a concern for its FGD projects because the coincidental increases of particulate from the associated material handling systems were included in the application and were less than the applicable significance level.
- On November 13, 2007, KDAQ issued an NOV for an exceedance of the 42 ppm NO_x limit for CT-7. DAQ subsequently rescinded the NOV on

January 28, 2008 after E. ON successfully demonstrated that when the test was corrected to 15 percent O_2, the result was less than 42 ppm.

- EON has submitted a 2007 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions (and other regulatory programs such as Acid Rain and Risk Management Planning) with the exception of a few items. These items are noted below in greater detail:
  - BR1, BR2, and BR3 were in continuous compliance except for numerous opacity and opacity trigger levels throughout the year. The report indicates that stack tests were not triggered. The opacity exceedances were mainly due to startups, shutdowns, load changes, blowing, precipitator trouble, and unit trip/upset. The SO_2 exceedances were due to fuel problems.
  - CT-7 experienced 38 exceedances of the 3-hour rolling NO_x average. The report indicates that all of the exceedances occurred during fuel oil commissioning and testing and that ALSTOM used CEMs during the events and ensures that actual emissions did not exceed the 42 ppm NO_x limit.
  - CT-7 experienced 2 heat input exceedances with no reason acknowledged.
- In 2003, EON commissioned an external Environmental Compliance audit by Audit Services for a review of the facility's compliance with federal, state, and local environmental regulations and corporate policies and procedures. The conclusion was that the facility maintained general compliance with all evaluated regulations, but had opportunities for improvement. The Environmental Procedures Manual has been completed; Revision 3 was issued in February of 2008.

  In addition to providing brief details on the 2006 NSR NOV, the 2008–2012 Operating Plan makes note of the following:
  - A new section of the Title V permit concerning periodic particulate monitoring could cause more frequent inspection and maintenance of the ESPs, larger derates due to opacity issues, and more particulate matter testing.
  - The facility is currently pursuing a change to the Title V permit concerning the NO_x limits from the CTs (perhaps CT-5 specifically). No other information concerning this change was provided to Black & Veatch.

- – The delivery/use of high sulfur coal may need to be delayed until BR1 and BR2 tie-ins to the FGD system are completed in order to prevent problems with managing two full-time coal piles and potential SO_2 exceedances from the use of high sulfur coal.
- A review of compliance data available on the EPA Enforcement & Compliance History (ECHO) website shows no current or historical violations of the Clean Air Act for the facility.

B.1.5.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is based on known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs no attempt in determining how these changes will affect this facility will be made. However, based on a review of the E.W. Brown Generating Station's documentation, the following identified items were noted because they have the potential to affect future operations plans for the facility:

- In 2006, E.ON determined that the E.W. Brown Generating Station – BR2 and BR3 were BART-eligible units. Following the BART guidance and conducting analyses focusing only on particulate due to the CAIR rule satisfying BART requirements for NO_x and SO_2, E.ON submitted a report in July 2007 to KDAQ which demonstrated that the E.W. Brown Generating Station BART-eligible units were exempt from BART requirements. EON indicated in email correspondence dated July 11, 2008, that KDAQ accepted the BART determination for this facility that BR2 and BR3 were exempt. However, it should be noted that since this determination, the CAIR rule has been vacated. Therefore, the aforementioned determination may no longer be valid. Additional information is contained in Section 4.0 on this issue.

B.1.5.3 Water.

B.1.5.3.1 Water Supply. Water supply for all plant waters is obtained from Herrington Lake, an artificial lake created in 1925 by damming the Dix River. KDEP's water withdrawal program requires a permit for water withdrawals greater than 10,000 gallons per day. Exceptions to the requirement include steam electric facilities regulated by the Kentucky Public Service Commission (KPSC) (KRS 151.140). Because

E.W. Brown Generating Station is regulated by the KPSC, a water withdrawal permit is not required.

Nevertheless, water use is monitored via the facility's KPDES[5] Wastewater Discharge Permit No. KY0002020, through Outfall 005, which is the plant intake. Although there is no specified numeric limit for flow, the facility is required to report the monthly average and daily maximum of flow, and monitor flow on a weekly basis. Other effluent characteristics that are monitored and reported include temperature, total suspended solids, water hardness, pH, and total recoverable metals.

According to the facility's DMR from May 2008, the average flow from Outfall 005 was 23.2 mgd, with a maximum flow of 27 mgd.

B.1.5.3.2 Wastewater Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if the discharge directly into surface waters. EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky (KDEP), which oversees the Kentucky PDES (KPDES) program.

E.W. Brown Generating Station has a KPDES wastewater discharge permit (KY0002020) issued by the KDEP in 2002. The permit expired on January 31, 2007. The application for renewal was not submitted on a timely basis (180 days before permit expiration) and was received by the KDEP on August 14, 2006. The KDEP deemed the application complete as of October 24, 2006. E.W. Brown Generating Station continues to operate under the terms of the 2002 permit until permit renewal is processed by KDEP. As stated in the ECHO Report, "If the CWA permit is past its expiration date, this normally means that the permitting authority has not yet issued a new permit. In these situations, the expired permit is normally administratively extended and kept in effect until the new permit is issued." (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is not unusual.)

The 2002 KPDES permit includes limits for effluent from Outfall 001 (combined wastewaters of ash pond overflow, including ash transport wastewaters, low volume wastes, cooling tower blowdown from Units 1 and 2, coal pile runoff, and storm water runoff), and metal cleaning wastes from internal Outfall 004 - ash pond); Outfall 002 (cooling tower blowdown and untreated storm water runoff); Outfall 003 (cooling tower

[5] See discussion in Wastewater Discharge paragraph following for a brief description of the NPDES/KPDES program.

blowdown and miscellaneous heat exchanges from Unit 3), and untreated storm water runoff. Limits and parameters appear to be typical for large power generation facilities and include the requirements to monitor and/or report temperature, flow, selected metals, residual chlorine. The permit was modified on June 28, 2004, to reduce the toxicity testing requirements from quarterly to annually.

Black & Veatch reviewed the discharge monitoring reports (DMRs) for calendar year 2007, and the DMR for May 2008, along with the ECHO Report mentioned above. No issues of noncompliance were noted in 2007 or in May of 2008. An exceedance of pH (4 percent) was noted in the third quarter of 2006, resulting in a NOV issued by the KDEP on November 27, 2006. The NOV stated that the facility's explanation attached to the DMR detailing the determination of cause of the violation was sufficient, and that no additional submittals would be required.

The 2002 KPDES permit also requires the development and implementation of a BMP Plan. The purpose of the BMP Plan is to prevent or minimize the potential for release of pollutants, via plant site runoff, spills and leaks, or sludge disposal, to surface waters of the US. The facility's BMP Plan is combined with its SPCC Plan, revised April 2008.

Based on the information reviewed in the DMRs, the maximum daily flow from the E.W. Brown Generating Station intake is below the trigger threshold requiring Section 316(b) review; therefore, it is assumed that Section 316(b) is not applicable to the E.W. Brown facility.

B.1.5.4 Solid and Hazardous Waste. E.W. Brown Generating Station produces general refuse trash (solid wastes), combustion byproducts such as fly ash (special wastes), and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.5.4.1 Solid Wastes. According to the Groundwater Protection Plan developed for the facility on February 19, 2008, general refuse trash is temporarily stored onsite in dumpsters and hauled offsite by a licensed contractor to an appropriate landfill. The plan states that the temporary nature of the waste, and the method in which it is managed, makes it a minimal threat to groundwater resources.

B.1.5.4.2 Special Wastes. E.W. Brown Generating Station generates combustion/coal byproducts, including bottom ash, fly ash, and FGD sludge. Bottom ash and fly ash are disposed of in the ATB in accordance with the KPDES Permit No. KY-

0002020. According to the KPDES permit, the Jordan Memorandum allows the discharge of air pre-heater wash waters and boiler fireside cleaning directly to the ATB with no numeric limitations or monitoring requirements imposed. Compliance with the KPDES permit, in turn, authorizes the facility to maintain the waste site under KDEP's special waste permit by rule (401 KAR 45.060). The ATB has been partially dredged out a number of times for beneficial reuse of coal ash offsite.

The construction of the elevated ATB will occur over a period of 12 years, or a total of five phases. Phase I of the ATB construction was reviewed and inspected by KDEP's Division of Water, Dam Safety and Floodplain Compliance on June 20, 2008, who granted approval, effective that date, to impound process wastewater. When all construction phases are complete, the expanded ATB will be at a final elevation of 962 feet and provide 6,700 acre-feet of storage - allowing the ATB to operate for another 20 years. During the facility visit, EON staff reported that Phase I of the expanded ATB has all required permits, and is ready to start receiving ash.

Permits/approvals received for Phase I of the expanded ATB include the following:

- KDEP Stream Construction Permit 16906[6] (for construction of dam) (Expiration December 18, 2008).
- KDEP General storm water permit (for construction) (Expiration September 30, 2007).
- Kentucky Heritage Council[7] (for construction).

Permits applied for but not received for Phase I of the expanded ATB include the following:

- KDEP NPDES permit (for operation).

Several of the ATB construction permits required submission of as-built plans and other documentation to inform the agencies of the completion of Phase I of the project. It was not clear to Black & Veatch whether all of these permit conditions had been

[6] Permit 16906 was issued December 18, 2007, authorizing construction of all 5 phases. Black & Veatch assumes that this permit supersedes Permit 15956, issued August 24, 2006, authorizing construction of Phases 1 and 2.

[7] Kentucky Heritage Council (KHC) reviewed the landfill expansion for potential impacts to cultural and historical resources. In its letter dated August 7, 2006, KHC states that '*work in the southern portion of the project area (including Phase I) may commence, as the area has been previously disturbed and no archaeological survey is required. However, the northern portion of the project, including borrow areas 4 and 5 (also known as Houp Farm) has not been previously disturbed and will require an archaeological survey. As agreed, the archaeological survey of the Houp Farm will be conducted immediately so as to facilitate the remainder of the project. The results of all investigations must be submitted for review, comment, and approval*'. No information was available to Black & Veatch regarding the status of the Houp Farm survey.

complied with. The facility should review all conditions of the construction permits to ensure that there are no outstanding conditions that require compliance.

Permits applied for but not required include the COE Section 404 permit[8] and the Section 401 Water Quality Certification from the KDEP.

B.1.5.4.3 Hazardous Wastes. The Resource Conservation and Recovery Act (RCRA) establishes a cradle-to-grave system for managing the generation, treatment, and disposal of hazardous wastes. Kentucky's requirements for hazardous waste generators are modeled after the EPA's and are found at 401 KAR 32 (standards applicable to generators of hazardous waste), which all hazardous waste generators are required to follow.

The three categories of hazardous waste generators regulated include the following:

- Large quantity generators (LQGs) (generating more than 2,200 pounds of hazardous waste per month);
- Small quantity generators (SQGs) (generating between 220–2,200 pounds of hazardous waste per month); and
- Conditionally exempt SQGs (CESQGs) (generating less than 220 pounds) of hazardous waste per month.

LQGs and SQGs are required to obtain a registration ID number; CESQGs are not. E.W. Brown Generating Station submitted its registration as a small quantity generator (KYD-000-622-951) on January 21, 2008. Federally regulated wastes handled at the site were identified in the registration only by waste code number, but likely include vehicle service wastes, batteries, spent fluorescent light tubes, waste paint, and spent solvents. There were no state regulated hazardous wastes identified in the registration form. According to the ECHO Report, the date of last hazardous waste inspection at the facility was identified as January 29, 2008; no formal enforcement actions or penalties have been imposed in the last 5 years.

B.1.5.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulations (40 CFR 112) set forth requirements for prevention of, preparedness for, and response to oil discharges at facilities storing or using oil in specified threshold amounts. Facilities storing in excess

[8] Work on the expanded ATB was initially authorized under the COE's nationwide Permit No. 39 (July 21, 2006). On September 7, 2007, in response to a request of jurisdiction determination from E-ON (date unknown), the COE determined that the ponds and other features within the proposed ash pond footprint were isolated waters and were not waters of the US, thus obviating the need for a Section 404 and Section 401 permit.

of 1,320 gallons of oil must develop and implement a SPCC Plan. The EPA revised its SPCC regulations in 2002, and extended the compliance dates on May 16, 2007[9]. As of this writing, existing facilities are required to revise their SPCC Plan in compliance with the 2002 regulations, and implement such plan, by July 1, 2009.

E.W. Brown Generating Station provided a copy of its Best Management Practices and Spill Prevention Control and Countermeasure Plan, revised April 2008. The Plan states that 'it will be in full compliance with the 2002 SPCC regulation revisions by the July 2009 compliance date'; however, the facility has already implemented many of the necessary changes. The Plan includes the required Applicability of Substantial Harm Criteria Form, signed and dated October 21, 2004, which indicates that E.W. Brown Station is a Substantial Harm Facility. According to the Material Inventory and Tank List, oil storage is approximately 2.8 million gallons.

In addition to an SPCC plan, facilities storing 1,000,000 gallons of oil or more may also be required to develop a Facility Response Plan (FRP). FRPs must be submitted to the EPA for approval, prior to implementation. Rules governing FRPs are also located at 40 CFR 112.

Black & Veatch received a copy of the April 2008 revision of the FRP, but did not receive a copy of the letter of approval of the FRP from the EPA. An FRP was prepared, in light of the quantity of oil currently stored at the facility, the completion of the Substantial Harm Facility certification in the SPCC plan, and the enforcement action taken by the EPA in 2005 regarding the October 2, 1999 spill of 38,000 gallons of diesel fuel into Cedar Branch Creek, for which the facility had not prepared an FRP, as required.

Other documented spills include the September 24, 2006 spill of 750 gallons of fuel oil, which leaked from a fuel oil return line that cracked and filled a manhole. Approximately 650 gallons were contained in the concrete vaults, and an estimated 100 gallons spilled onto the ground; reportable spill quantity was 75 gallons. On November 30, 2007, 650 gallons of diesel fuel spilled out into the Unit 1 fuel oil tank berm, resulting in a reportable spill quantity of 75 gallons. The root cause of the spill is currently under investigation, but is reported to be from a leak in the line off the fuel oil pump discharge piping. Both spills were documented as being cleaned up, with contaminated soil removed and disposed of.

[9] Additional changes to EPA's SPCC rules are expected when rules proposed on October 1, 2007 become finalized.

B.1.5.6 Emergency Planning. As required by EPCRA/CERCLA, certain facilities that use or produce hazardous substances, extremely hazardous substances, and toxic chemicals in greater than specified thresholds are subject to a number of requirements, including federal, state, and local reporting requirements.

Sections 302 and 303 of EPCRA require facilities with chemicals designated as extremely hazardous substances (EHS) to work with planning officials to develop comprehensive emergency plans.

Section 304 requires reporting of accidental releases of EHSs.

Sections 311 and 312 require facilities to provide Material Safety Data Sheets (MSDSs) and chemical inventories of chemicals at their facilities to state and local agencies.

Section 313 of EPCRA requires certain facilities to report on and submit an annual TRI Report to the EPA. These chemicals and chemical categories are listed in 40 CFR Part 372. Submittals continue in the same fashion every year thereafter. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities, and to allow better response should a chemical release occur. Releases governed by the rules include all emissions into the environment including air, water, and land. Facilities are only subject to the provisions of Section 313 if they satisfy all three criteria relating to: (1) SIC code classification, (2) hours worked/number of full time employees at the facility, and (3) use of any of the Section 313 chemicals in amounts greater than threshold quantities specified.

Black & Veatch reviewed an inventory of chemicals used on site as detailed in the BMP and SPCC plan and the 2008 Groundwater Protection Plan. Chemicals used on site that trigger Section 312 reporting include sodium hydroxide, sulfuric acid, turbine oil, diesel fuel, phosphoric acid, anhydrous ammonia, hydrazine, sodium hypochlorite, sulfur, chlorine, vanadium pentoxide, ethylene glycol, styrene vinyl ester resin solution, and propane. The facility's Section 312 inventory was submitted to the Mercer County Emergency Planning Committee on February 21, 2008. Copies of the report were provided to the Harrodsburg and Burgin Fire Departments. No information was provided regarding the occurrence of any EHS accidental releases in 2007.

EON provided a data sheet of TRI Releases for its KU and LG&E Plants. The data sheet summarizes total reportable and non-reportable releases, comprising air, land, and water releases, and transfers offsite, in pounds per year.

The E.W. Brown Station used anhydrous ammonia for the CT inlet air cooling ice plant. Based on the use and quantity of ammonia stored, the process is subject to specific environmental regulations under Section 112(r) of the Clean Air Act administered by the EPA for chemical accident prevention. Specifically, the RMP provisions (published

June 20, 1996) are found in 40 CFR Part 68. Additionally, the plant is also subject to the OSHA regulations 29 CFR 1910.110 for Process Safety Management. These two regulations address the safe use and handling of hazardous chemicals. The RMP summary for 2004 was provided.

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of this information.

EON provided a receipt from EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

B.1.5.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with facility staff.

B.1.5.8 Other Environmental Issues. No other known issues of concern were identified from the review.

B.1.6 Green River County Generating Station Environmental Review

Permit Status & Regulatory Compliance

Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of this environmental section did not visit the site. Key documents provided by EON for this review included the following:

- August 6, 2007 (issuance date) KDAQ Air Quality Permit Title V Operating Permit (Permit No. V-06-014).
- Partial summary particulate test report for GR4 conducted on June 19 and 20, 2008 by Catalyst Air Management, Inc., report not dated.
- 2007 Emissions Inventory Spreadsheet.
- 2007 Annual Air Compliance Certification dated January 28, 2008.
- KDEP Air Compliance Inspection Report from inspection on August 10, 2005.
- Internal EON correspondence for NOV from August 4, 2006.
- KDEP letter for NOV dated August 1, 2006.
- November 1, 2001 (effective date) KPDES Permit (Permit. No. KY0002011) issued by KDEP (as modified July 1, 2004).
- Monthly Discharge Monitoring Reports for calendar year 2007.
- May 14, 2007 KPDES Permit Renewal Application.
- 2005 Groundwater Protection Plan.
- October 2006 Best Management Practices and SPCC Plan.
- April 5, 2005 Corrective Action Report by SMR Engineering.
- Spill/Release Reporting Form and attachments for August 14, 2005 release event.
- TRI Spreadsheet for 2007.
- Tier Two Emergency and Hazardous Chemical Inventory Report for 2007.
- Selected correspondence with regulatory agencies including April 20, 2005 remediation no further action letter from KDEP, and other letters as cited in this report.
- Green River Environmental Compliance Manual – January 2008.
- 2008-2012 Facility Operating Plan (revised December 2007).

Black & Veatch also obtained a summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.

B.1.6.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at Green River as summarized in the Green River Environmental Compliance Manual.

B.1.6.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this documentation review was to attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.1.6.2.1 Air Program Compliance. The Green River Station's air permit is a combined PSD and Part 70 Title V operating permit (Permit No. V-06-014,) and was issued to Kentucky Utilities Company on August 6, 2007. The combined PSD/Part 70 operating permit is in effect for 5 years from the effective date. It should be noted that the term for the Acid Rain permit (included in the combined permit) is coincident with the term of the Operating Permit and expires on August 6, 2012.

The following identified items are findings from the document review:

- The existing emission units consist of Boiler 4 (GR3) and Boiler 5 (GR4) known in the permit as Emission Units 3 and 4, respectively. Boilers 1–3 (Emission Units 1 and 2) have been retired and removed from the operating permit (Permit No. V-06-014).
- The operating permit requires particulate testing for GR3 and GR4 to re-establish the correlation between opacity and particulate matter emissions. Based on a partial test report for testing conducted by Catalyst Air Management, Inc. in June 2008, the tests were conducted within the period required by the permit. The particulate test indicated compliance with the permit limit, and nine test runs were performed to determine correlation between opacity and particulate matter. GR4 correlation results indicate that at higher particulate matter emission levels, but less than the permitted emission limit, the 20 percent opacity limit was exceeded. It should be

noted that the document only consisted of two report summary pages and did not comprise the entire report.

- The 2008-2010 MTP operating plan indicated that many areas of the station and boilers have undergone modifications—most of which, based on this limited information, could be considered replacement-in-kind or maintenance activities. However, this document specifically notes that in January 2002, the GR3 and GR4 steam turbine generators underwent major turbine overhauls as a part of their normal outage maintenance cycle (the document also notes that GR3 was overhauled in 2003 and GR4 in 2005). Many recent EPA NSR violations and related court decisions have determined that owners have not obtained permits for steam turbine modifications or, at a minimum, have not shown that these changes were not considered modifications prior to making the change. This issue, and potentially the aforementioned maintenance issues, is a concern due to the fact that these types of modifications can debottleneck electric generating units and allow for an increased utilization of the boiler (i.e., unit could operate more hours and/or potentially emit more pollutants than it has done previously). No additional information regarding these overhauls or associated air permit determinations or permit actions was provided to Black & Veatch for review.
- EON has submitted a 2007 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions with the exception of a few items. These and other items are noted below in greater detail:
  - The 2007 Annual Air Compliance Certification indicates that Unit 3 (Boiler No. 4) and Unit 4 (Boiler No. 5) are in compliance with its SO_2, particulate matter, and opacity limits. The report indicates Unit 3 and Unit 4 had 129 and 63 opacity exceedances, respectively, greater than their 20 percent permit limit, due to unit upset, load change, or soot blowing, and unit startup. Additionally, on August 1, 2006 the station received a notice of violation due to Unit 4 opacity violations. The opacity limit was noted as 40 percent but the current operating permit, issued after this period, indicates the opacity limit of 20 percent. This limit may have been rescinded as indicated in an internal EON email due to timing of correspondence between KDAQ and the station. Opacity

exceedances may be an ongoing issue for this station. No additional information on this issue was provided for review.

- It was noted that Method 9 tests were conducted every 14 days, but no additional information on the Method 9 results were available for review.

- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

B.1.6.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is dependent upon known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs, no attempt in determining how these changes will affect this facility will be made in this report. However, based on a review of the Green River Station's documentation, no future plans or facility modifications were identified which would require air considerations.

B.1.6.3 Water.

B.1.6.3.1 Water Supply. Water supply for cooling water at Green River Station is from the Green River. Drinking water is supplied by a municipal system.

B.1.6.3.2 Water Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

Green River Station has a KPDES wastewater discharge permit (Permit. No. KY0002011) issued by KDEP in 2001 (as modified July 1, 2004). The permit expired on October 31, 2004. EON submitted a timely renewal application in April 2004 and a letter from KDEP on August 16, 2004, acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. Green River continues to operate under the terms of the 2001 permit until permit renewal is processed by KDEP. (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical.)

The 2001 permit includes limits for such wastewater discharges as once-through cooling water, ATB discharge, and storm water runoff. Limits appear in general to be typical for power generation facilities. The permit requires monitoring and/or reporting of parameters such as temperature, flow, selected metals, residual chlorine, and whole effluent toxicity.

Black & Veatch reviewed discharge monitoring reports for calendar year 2007 and the results of 2007 toxicity testing (reported in a letter from Microbac Laboratories on October 2, 2007). In June 2006, the facility plant intake flow was calculated at 37 percent of river flow, exceeding the permit limit maximum of 25 percent. The EPA ECHO data base lists a September 19, 2007, letter of Violation/Warning. A subsequent letter from KDEP on November 28, 2007, rescinded the notice of violation and noted that the KDEP Division of Water had given verbal approval to exceed the withdrawal rate.

According to EPA ECHO, the Green River Station facility was inspected in 2007. No additional compliance concerns other than those identified above were listed in the data base above.

B.1.6.3.3 Clean Water Act Section 316(b) Compliance. Section 316(b) of the CWA requires applicants for a NPDES wastewater discharge permit to minimize adverse impacts to aquatic ecosystems from cooling water intake structures. The withdrawal of cooling water has the potential to cause adverse environmental impacts due to impingement and mortality of organisms, primarily fish, on screens that protect the intake system, and through entrainment and mortality of small organisms, primarily fish eggs and larvae, that pass through those screens and through the plant's entire cooling system. Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the best available technology (BAT) for minimizing adverse environmental impacts.

The EPA published its final NPDES regulations addressing cooling water intake structures for Phase II facilities[10] in April 2004. The Phase II rules gave facilities the option of establishing BAT by demonstrating that (1) existing design and construction technologies meet the specified standards, (2) a combination of existing and new design and construction technologies meet the specified standards, or (3) a site-specific determination of BAT for minimizing adverse environmental impact is appropriate for the site. The location, design, construction and capacity of cooling water intake

[10] Phase II facilities are large existing power generation facilities withdrawing more than 50 million gallons per day (mgd) of cooling water.

structures are considered when evaluating BAT designs. Other critical factors can include the shape of the shoreline, water velocity, size and placement of screens, and the use of biocides such as chlorine to control bacterial growth and mollusks such as zebra mussels.

In order to demonstrate BAT design, it is necessary to perform a Section 316(b) analyses. In general, a Section 316(b) analysis discusses the following:

- The engineering and biological data used and assumptions made in the assessment;
- The biological characteristics of local fish populations;
- The anticipated effects of the proposed intake design and other reasonable design alternatives on local fish populations; and
- The general economic considerations for each reasonable alternative.

A conclusion regarding the BAT design for the proposed project is then made based on Items 1 through 4 above. The EPA (or the state permitting agency) will review the BAT analysis when processing the NPDES renewal application, which is conducted every 5 years.

Many facilities were in the process of performing their Section 316(b) analyses when EPA suspended the requirements for cooling water intake structures at Phase II existing facilities, pending further rulemaking. The rule was suspended on March 20, 2007, in response to the Second Circuit Court of Appeals decision in *Riverkeeper, Inc., v. EPA.*

Section 316(b) is applicable to the Green River Station because it withdraws more than 50 mgd. Section 316(b) analyses that were performed for the Green River Station include an Impingement Mortality Characterization Study of the Green River Station, and a Biological Characterization Study of the Green River, in November 2007. The data presented in the studies will likely be useful in determining compliance with the revised Phase II regulations, when published.

B.1.6.4 Solid and Hazardous Waste. Green River Station produces combustion byproducts such as fly ash, general refuse trash, and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.6.4.1 Combustion/Coal Byproducts. Green River Station generates bottom ash, fly ash, and boiler slag. FGD byproduct was previously produced on one unit, but that unit has since been retired, along with the FGD system. Coal ash is accumulated in an ash pond for subsequent reuse. For basins which are under the 401 KAR 45:060

Kentucky special waste permit-by-rule, the only monitoring requirements are the requirements from the KPDES permits.

As observed during the site visit by Black & Veatch, adequate long-term options for disposal and storage of combustion products is an important consideration for Green River Station. Disposal of fly ash and bottom ash will be an ongoing issue due to the limited disposal capacity on site. Pond capacity currently is estimated at about 2.5 years. This issue is being addressed by delivering ash for local beneficial reuse projects. The current customer will extend purchases an additional 2 years to 2013, and plant management is working with another customer on plans that will extend the life of the ponds several more years.

B.1.6.4.2 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance at Green River Station (including office waste, maintenance waste, and other nonhazardous waste) is stored onsite in dumpsters before being transferred to a licensed commercial landfill.

B.1.6.4.3 Hazardous Waste. As noted in the Groundwater Protection Plan, the Green River facility is a Conditionally Exempt Small Quantity Generator (CESQG). (CESQC is defined in Kentucky regulations (401 KAR 30) as a facility that accumulates less than 220 pounds generated in any one calendar month and less than 2200 pounds of total waste on site at any time.) No hazardous waste compliance issues were noted in documents reviewed. According to the EPA ECHO database, KDEP conducted a hazardous waste inspection in August 2004 and found no violations or compliance issues.

B.1.6.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines and including process oil use in the SPCC plan. EPA has amended the SPCC requirements of the Oil Pollution Prevention regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[11] on SPCC plans require that existing facilities operating prior to August 16, 2002 amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Green River Station has a Best Management Practices and SPCC Plan dated October 2006. This SPCC plan responds to the EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. The Green River Station handles thousands of gallons of oil products including fuel and a variety of transformer oil and lubricants. The largest oil tanks listed in the SPCC plan are two 25,000 gallon diesel/fuel oil tanks. The Green River SPCC plan describes compliance with EPA regulations effective in 2009.

Green River Station had two reported spill events in 2005. An estimated 1,000 gallon spill of oil from a 500,000 gallon tank resulted in removal of the tank, site remediation, and receipt of an April 20, 2005, letter from KDEP noting no further action is needed. Another spill in 2005 from a transformer reportedly hit by lightening was reported on August 14, 2005. A follow-up inspection by KDEP on December 21, 2005, and an email from EON to KDEP on December 21, 2005, indicated that results of spill cleanup were satisfactory.

Otherwise, information provided indicates that no major additional actions and expenses appear to be necessary for oil compliance.

B.1.6.6 Emergency Planning. Black & Veatch reviewed an inventory of chemicals used onsite as detailed in the Groundwater Protection Plan and in the 2007 TRI spreadsheet provided by EON. Section 313 of the EPCRA requires certain facilities to submit an annual TRI Report to the EPA. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities and to allow better response should a chemical release occur.

According to the TRI spreadsheet, the type and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at Green River appear to be typical for coal fired power plants. EON provided a receipt from the EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

Under EPA regulations, facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year and make the form available to the public by submitting it to state emergency response commissions and the local emergency planning commissions. Black & Veatch reviewed

[11] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

the 2007 Tier II report for Green River and found the list of chemicals reported to be typical for coal power plants. The Green River Tier II 2007 report was submitted to the Central City Fire Department and Muhlenberg County Emergency Planning Committee with a postal return receipt attached.

Green River Station does not store ammonia and is not required to have an RMP under the chemical accident prevention provisions (40 CFR 68).

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of the provided information.

B.1.6.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.1.6.8 Other Environmental Issues. Observations from Black & Veatch's document review indicated a generally high level of environmental awareness in current and recent operations of the Green River Station facility and a proactive approach to environmental management at the facility. Professional environmental staff located at both the facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning.

Documents provided by EON did not include studies of any preexisting environmental conditions at the Green River Station site (prior to current operations) or any investigations of known soil/groundwater contamination issues from past operations including prior ash/sludge landfills/basins, from prior and ongoing management of coal and limestone onsite, and from any historical spills or other previous releases at the site other than the 2005 releases reported above. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.1.7 Tyrone Generating Station Environmental Review
Permit Status & Regulatory Compliance
Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of this environmental section did not visit the site. Key documents provided by EON for this review included the following:

- July 2, 2007 (effective date) KDEP, Division of Air Quality (KDAQ) Air Quality Permit (Permit No. V-05-018).
- 2007 Emissions Inventory Spreadsheet.
- EON internal Audit dated August 6, 2007.
- 2007 Annual Air Compliance Certification dated January 24, 2008.
- February 1, 2002 (effective date) KPDES Permit (Permit. No. KY0001899) issued by KDEP(as modified July 1, 2004).
- Monthly Discharge Monitoring Reports for Calendar 2007.
- August 14, 2006 KPDES Permit Renewal Application.
- January 2007 Groundwater Protection Plan.
- May 2006 Best Management Practices and SPCC Plan.
- TRI Spreadsheet for 2007.
- Tier Two Emergency and Hazardous Chemical Inventory Report for 2007.
- Tyrone Station Environmental Compliance Manual – March 2007.
- 2008-2012 Operating Plan (undated).

Black & Veatch also obtained a summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.

B.1.7.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, onsite ash holding and disposal facilities, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at Tyrone Generating Station as summarized in the Tyrone Environmental Compliance Manual.

B.1.7.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, the goal of this documentation review was to attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.1.7.2.1 Air Program Compliance. The Tyrone Generating Station's air permit is a combined PSD and Part 70 Title V operating permit (Permit No. V-05-018). It was completed on August 20, 2005, issued to Kentucky Utilities Company on July 2, 2007, and has not undergone any revisions. The combined PSD/Part 70 operating permit is in effect for 5 years from the effective date. The term for the Acid Rain permit (included in the combined permit) for the Tyrone Generating Station is coincident with the term of the Operating Permit.

The following identified items are findings from the document review:

- EON has submitted a 2007 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions with the exception of a few items. These and other items are noted below in greater detail:
  - The 2007 Annual Air Compliance Certification indicates that Unit 3 (Boiler 5) is in compliance with its NO_x, SO_2, particulate matter, and opacity limits. This emission source also has a permit requirement to use opacity as an indicator of particulate matter emissions and compliance. The report indicates Unit 3 had six opacity exceedances greater than their 40 percent threshold due to unit upset. No supporting information regarding particulate matter was provided to Black & Veatch for review.
  - It was noted that Method 9 tests were conducted every 14 days, but no additional information on the Method 9 results were provided to Black & Veatch for review.
  - The report noted that a particulate matter and opacity trigger was tentatively scheduled for the week of April 21, 2008 but no additional information on this issue was provided to Black & Veatch for review.
- EON conducted an internal environmental audit in December 2006 and issued the final audit report on August 6, 2007. There were no specific results of the audit for air related issues. However, the audit generally indicated that recordkeeping and reporting requirements were the focus of the audit, but that the station maintains general compliance with required environmental regulations. Additionally, this report noted that Stacks 1

and 2 (consisting of Boilers 1-4) were retired in February 2007. The 2007 Annual Air Compliance Certification also notes that these units were not operated during the reporting period.

- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

B.1.7.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_X, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is hinged on known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the uncertainty resulting from changes in the federal air programs, no attempt in determining how these changes will affect this facility will be made. However, based on a review of the Tyrone Generating Station's documentation, no future plans or facility modifications were identified that would require air considerations.

B.1.7.3 Water.

B.1.7.3.1 Water Supply. Water supply for cooling water at Tyrone Generating Station is from the Kentucky River. Two onsite wells provide groundwater that can be used for demineralized boiler water, miscellaneous process equipment cooling, or flows to the ATB. Drinking water is obtained from the city of Tyrone.

B.1.7.3.2 Water Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain NPDES permits if their discharges go directly to surface waters. EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

Tyrone Generating Station has a KPDES wastewater discharge permit (Permit. No. KY0001899) issued by KDEP (effective in 2002 as modified July 1, 2004). The permit expired on January 31, 2007. EON submitted a renewal application in August 14, 2006 and a letter from KDEP on August 24, 2006 acknowledged that the renewal application was determined to be complete and will be technically reviewed in the future. Tyrone Generating Station continues to operate under the terms of the 2002 permit until permit renewal is processed by KDEP. (Black & Veatch notes that such delay of permit renewal for periods of 2 years or longer has been typical throughout the country in recent years. Operation under an expired permit is similarly typical.)

The 2002 permit includes limits for such wastewater discharges as once-through cooling water ash pond discharge and storm water runoff. Limits appear in general to be typical for power generation facilities. The permit requires monitoring and/or reporting for such parameters as temperature, flow, selected metals, residual chlorine, and annual reporting of whole effluent toxicity.

Black & Veatch reviewed discharge monitoring reports for calendar year 2007 and the results of 2007 toxicity testing (reported in a letter from Microbac Laboratories on October 15, 2007 and a previous letter on October 3, 2007). The first toxicity sample failed the test and in the discharge monitoring report the failure was attributed to an unrepresentative sample from low flow and a clogged discharge. The subsequent sample reported on October 15 met permit requirements. For the March 2007 monitoring period, the Biological Oxygen Demand (BOD) average monthly concentration of 40 mg/liter exceeded the permit limit concentration of 30 mg/liter. Black & Veatch identified no additional issues.

The EPA ECHO database lists a June 29, 2007 and a February 11, 2008 Letter of Violation/Warning, assumed to be related to the BOD and toxicity exceedances discussed above. (Black & Veatch notes that infrequent exceedances of a permit level may be a typical expectation for an industrial facility due to such events as operational variations or laboratory problems. However, the state agency may issue an NOV for any permit exceedance.)

According to the EPA ECHO database, the Tyrone Generating Station was inspected in 2006 and 2007. No compliance concerns beyond those discussed above were identified in the database.

B.1.7.3.3 Clean Water Act Section 316(b) Compliance. Section 316(b) of the CWA requires applicants for a NPDES wastewater discharge permit to minimize adverse impacts to aquatic ecosystems from cooling water intake structures. The withdrawal of cooling water has the potential to cause adverse environmental impacts due to impingement and mortality of organisms, primarily fish, on screens that protect the intake system, and through entrainment and mortality of small organisms, primarily fish eggs and larvae, that pass through those screens and through the plant's entire cooling system. Section 316(b) requires that the location, design, construction and capacity of cooling water intake structures reflect the BAT for minimizing adverse environmental impacts.

EPA published its final NPDES regulations addressing cooling water intake structures for Phase II facilities[12] in April 2004. The Phase II rules gave facilities the option of establishing BAT by demonstrating that (1) existing design and construction technologies meet the specified standards, (2) a combination of existing and new design and construction technologies meet the specified standards, or (3) a site specific determination of BAT for minimizing adverse environmental impact is appropriate for the site. The location, design, construction and capacity of cooling water intake structures are considered when evaluating BAT designs. Other critical factors can include the shape of the shoreline, water velocity, size and placement of screens, and the use of biocides such as chlorine to control bacterial growth and mollusks such as zebra mussels.

In order to demonstrate BAT design, it is necessary to perform a Section 316(b) analyses. In general, a Section 316(b) analysis discusses the following:

- The engineering and biological data used and assumptions made in the assessment;
- The biological characteristics of local fish populations;
- The anticipated effects of the proposed intake design and other reasonable design alternatives on local fish populations; and
- The general economic considerations for each reasonable alternative.

A conclusion regarding the BAT design for the proposed project is then made based on Items 1 through 4 above. EPA (or the state permitting agency) will review the BAT analysis when processing the NPDES renewal application, which is conducted every 5 years.

Many facilities were in the process of performing their Section 316(b) analyses when EPA suspended the requirements for cooling water intake structures at Phase II existing facilities, pending further rulemaking. The rule was suspended on March 20, 2007, in response to the Second Circuit Court of Appeals decision in *Riverkeeper, Inc., v EPA.*

Section 316(b) is applicable to the Tyrone Generating Station because it withdraws more than 50 mgd. Section 316(b) analyses that were performed for the Tyrone Generating Station include an Impingement Mortality Characterization Study for the Tyrone Generating Station. The data presented in the study will likely be useful in determining compliance with the revised Phase II regulations, when published.

[12] Phase II facilities are large existing power generation facilities withdrawing more than 50 million gallons per day (mgd) of cooling water.

B.1.7.4 Solid and Hazardous Waste. Tyrone Generating Station produces combustion byproducts such as fly ash, general refuse trash, and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.1.7.4.1 Combustion/Coal Byproducts. Tyrone Generating Station generates bottom ash, fly ash, and slag. Coal ash is accumulated in an ATB for subsequent reuse. For basins which are under the 401 KAR 45:060 Kentucky special waste permit-by-rule, the only monitoring requirements are the requirements from the KPDES permits.

As observed during the site visit by Black & Veatch, adequate long-term options for disposal and storage of combustion products is an important consideration for the Tyrone Station. If local beneficial reuse projects do not continue as in the past, costs of ash disposal will significantly increase. The higher operating costs for the unit would need to be considered as a negative impact in the evaluation of the continued viability of this small, older unit.

B.1.7.4.2 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance at Tyrone Generating Station (including office waste, maintenance waste, and other nonhazardous waste) is stored onsite in dumpsters before being transferred to a licensed commercial landfill.

B.1.7.4.3 Hazardous Waste. As noted in the 2007 Groundwater Protection Plan, the Tyrone Generating Station is a Conditionally Exempt Small Quantity Generator (CESQG) of hazardous waste. CESQC is defined in Kentucky hazardous waste regulations (401 KAR 30) as less than 220 pounds generated in any one calendar month and less than 2200 pounds of total waste is accumulated on site at any time. No hazardous waste compliance issues were noted in documents reviewed. According to the EPA ECHO database, KDEP conducted a hazardous waste inspection in May 2008 and found no violations or compliance issues.

B.1.7.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines, and including process oil use in the SPCC plan. In 2007, the EPA amended the SPCC requirements to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[13] on SPCC plans require that existing facilities operating prior to August 16, 2002 amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Tyrone Generating Station handles thousands of gallons of oil products, including fuel tanks and a variety of transformer oil and lubricants. The largest oil tank identified in the SPCC plan is a 500,000 gallon diesel/fuel oil tank in an earthen containment area.

Tyrone Generating Station has a Best Management Practices and Spill Prevention, Control and Countermeasures Plan dated October 2006. This SPCC plan responds to EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. The Tyrone Station SPCC plan and Facility 2008-2011 Operating Plan describes the goal of compliance with EPA regulations as of the 2009 effective date of the regulations.

Additionally, the facility has a 14,000 gallon underground flow-through process tank which, as described in the Tyrone Groundwater Protection Plan (January 2007), is exempted from underground storage tank (UST) registration and monitoring requirements, according to Federal UST Regulations 40 CFR Part 280 and Kentucky Division of Waste Management UST Regulations 401 KAR 42:011 through 42:200. This tank is filled from the 500,000 gallon above ground storage tank and serves as a transfer tank to supply and meter fuel for the unit boilers and the building heat auxiliary boiler. The Groundwater Protection Plan notes that the tank inventory is checked several times per day and reconciled daily or weekly, depending upon operations.

According to the Black & Veatch site visit and EON operating plans, EON has plans in 2008 to replace the existing 500,000 gallon tank, underground tank, and underground piping with two new 50,000 gallon tanks and a double-walled aboveground piping system by July 2009.

B.1.7.6 Emergency Planning. Black & Veatch reviewed an inventory of chemicals used onsite as detailed in the Groundwater Protection Plan and in the 2007 TRI spreadsheet provided by EON. Section 313 of the EPCRA requires certain facilities to submit an annual TRI Report to the EPA. The purpose of TRI reporting is to inform local

[13] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

communities of potential hazards associated with TRI chemicals and facilities and to allow better response should a chemical release occur.

According to the TRI spreadsheet, the type and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at Tyrone appear to be typical for coal power plants. EON provided a receipt from the EPA dated June 18, 2008 confirming that the TRI submission for calendar year 2007 was received into the EPA database.

Under EPA regulations, facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year and make the form available to the public from state emergency response commissions and the local emergency planning commissions. Black & Veatch reviewed the 2007 Tier II report for Tyrone Generating Station and found the list to be typical for coal power plants. The Tyrone Generating Station Tier II 2007 report was submitted to the Versailles Fire Department and Woodford County Emergency Planning Committee with a postal return receipt attached.

Tyrone Generating Station does not store ammonia and is not required to have an RMP under the chemical accident prevention provisions (40 CFR 68).

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of the provided information.

B.1.7.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.1.7.8 Other Environmental Issues. Observations from Black & Veatch's document review indicated a generally high level of environmental awareness in current and recent operations of the Tyrone Generating Station facility. Professional environmental staff located at both the facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning.

Documents provided by EON did not include studies of any preexisting environmental conditions at the Tyrone Generating Station site (prior to current operations) or any investigations of known soil/groundwater contamination issues from past operations including prior ash landfills/basins, from prior and ongoing management of coal onsite, and from any historical spills or other previous releases at the site. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.2 Combustion Turbine Plants

B.2.1 Trimble County Station Combustion Turbines Environmental Review

Permit Status & Regulatory Compliance

Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at Trimble County Station for the simple cycle gas units Numbers 5-10.

Permit status, compliance with permit requirements, and regulatory compliance for these CT units were addressed in Subsection 2.1.4, Permit Status and Regulatory Compliance for Trimble County Unit 1 (TC1). The major permits for these units include the KDAQ Air Quality Permit and the KPDES permit. Additional key documents include the BMP Plan and SPCC Plan, the TRI spreadsheet provided by EON and the Tier Two Emergency and Hazardous Chemical Inventory Report. These permits, plans, and reports include the CTs. Refer to Subsection 2.1.4 for a detailed discussion of compliance status.

The most significant findings of the environmental review are listed below:

B.2.1.1 Current Environmental Compliance.

B.2.1.2 Air. EON has submitted a 2007 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions with the exception of a few items. These are noted below:

- The current air construction and operating permit (Permit No. V-02-043, Revision 3) notes the CO emission limit for the TC CTs is 9 ppm (by volume at 15 percent oxygen, on a dry basis), but the 2007 Annual Air Compliance Certification indicates that the TC CTs CO emissions limit is 9.5 ppm. Based on the 9.5 ppm CO emissions limit noted in the report, no excess emissions were reported for these units. However, no additional CO emissions information on individual TC CTs was available for review to determine if these units were exceeding their 9 ppm CO emissions limit.
- The current air construction and operating permit (Permit No. V-02-043, Revision 3) notes that the NO_x annual emissions limit for the TC CTs is 9 ppm (by volume at 15 percent oxygen, on a dry basis) and 12 ppm on a hourly basis. The 2007 Annual Air Compliance Certification indicates that several of the TC CTs exceeded their emission limit in during the monthly periods of April, May, and June 2007.

The 2007 Annual Air Compliance Certification indicates that the CT NO_x CEMs for all six units were unavailable for greater than 20 percent of their operating time.

On March 8, 2007, KDEP issued an NOV indicating that EON had failed to obtain a storm water discharge permit for the construction of a transmission construction lay-down site. In response to this NOV, on March 13, 2007, EON provided a written response to KDEP confirming that EON staff members had been informed of the requirements for storm water control, including the requirement for permits and BMP plans. They also held discussions with EON's Supply Chain to modify contract language and bid specifications to include requirements for construction runoff permitting and best management practices to prevent erosion and control sedimentation. Further, EON provided a completed Notice of Intent form and a Storm Water BMP. This response from EON adequately addressed the issues identified in the NOV.

B.2.2 E.W. Brown Combustion Turbines Environmental Review

Permit Status & Regulatory Compliance

Permit status, compliance with permit requirements, and regulatory compliance for these CT units were addressed in Subsection 2.5.4, Permit Status and Regulatory Compliance for E.W. Brown Generating Station (E.W. Brown). The major permits for E.W. Brown CT units include the KDAQ Air Quality Permit and the Kentucky Pollutant Discharge Elimination System (KPDES) permit. Additional key documents include the BMP Plan and SPCC Plan, the TRI spreadsheet provided by EON and the Tier Two Emergency and Hazardous Chemical Inventory Report. These permits, plans, and reports include the CTs. Refer to Subsection 2.5.4 for a detailed discussion of compliance status.

According to NOV documentation provided by EON on August 22, 2008, the E.W. Brown Generating Station CTs have received one NOV. On November 14, 2007, the KDAQ issued an NOV for an exceedance of the 42 ppm limit for NO_x recorded during emissions testing on CT No. 7 in April 2007. EON provided documentation that the actual NO_x concentrations measured during this test, after correction for 15 percent oxygen on a dry basis, were below permit limits. After reviewing this documentation, KDAQ formally rescinded the November 14, 2007, NOV on January 28, 2008. The KDEP letter verifying the rescinding of the NOV was provided to substantiate the resolution of this issue.

B.2.2.1 Current Environmental Compliance.

B.2.2.2 Air. The Year 2007 emissions reports for Unit 7 showed that there were a multitude of high NO_x emissions periods that were reported. The reason code is unacknowledged so it is uncertain of the cause of this problem, but due to the nature of exceedances that they have the same magnitude, the exceedances may have been caused by the same problem. This problem would need to be rectified to ensure future compliance.

B.2.3 Paddy's Run Station Combustion Turbines
Permit Status & Regulatory Compliance
Basis for Review

The environmental review was based on documents provided by EON and on observations from Black & Veatch staff who visited the facility in July 2008. Authors of this environmental section did not visit the site. Key documents provided by EON for this review included the following:

- December 22, 1999 (issuance date) Jefferson County APCD Air Quality Title V Operating Permit (Permit No. 130-97-TV).
- Jefferson County APCD Construction Permit (Permit No. 48-00-C) Effective Date: February 28, 2002.
- 2007 Emissions Inventory Spreadsheet.
- 2007 Annual Title V Compliance Certification dated April 15, 2008.
- External environmental audit by Audit Services dated August 6, 2004.
- External environmental audit by Murdock, Goldenburg, Schneider, and Groh, LPA dated March 2007.
- External environmental audit by Audit Services dated August 17, 2007.
- Petition letter to the EPA for NO_x Budget Program Emission Allowance Reconciliation, dated March 31, 2008, without attachments.
- Letter to the EPA for Certification Application for use of Low Mass Emission Monitoring Methodology, dated March 31, 2008.
- Letter to the EPA for Submission of the Monitoring Plan Information, dated March 31, 2008.
- Letter to the Air Pollution Control District of Jefferson County for Submission of the Monitoring Plan Information, dated March 31, 2008.
- Title V Permit Application Renewal, submitted to Louisville Metro Air Pollution Control District, dated June 11, 2004.
- July 1, 2008 (effective date) Kentucky Pollutant Discharge Elimination System (KPDES) Permit (Permit. No. KY0002071) issued by KDEP.
- Monthly Discharge Monitoring Reports for calendar year 2007.
- 2007 Groundwater Protection Plan.
- September 2007 Best Management Practices and SPCC Plan.

- Tier Two Emergency and Hazardous Chemical Inventory Report for 2006.
- 2008-2012 Cane Run Operating Plan (revised December 2007 – includes Paddy's Run).

Black & Veatch also obtained a summary of the facility's compliance status from the EPA ECHO database on August 14, 2008.

B.2.3.1 Current Environmental Compliance. Primary environmental compliance programs at the facility are associated with air emission limits, wastewater discharge limits, management of oil products, and safe management of chemical materials used onsite. Significant ongoing compliance programs are well established at Paddy's Run.

B.2.3.2 Air. The goal of the air environmental review was to review available documentation and summarize specific compliance issues related to the facility. The review of this documentation should not be considered an all-inclusive and comprehensive air environmental compliance audit consisting of verification of each permit condition of the application air permit(s) for each unit at the facility. Instead, this documentation review was to attempt to identify issues that may be potential concerns. It is possible that other compliance issues exist that were not identified in the available information.

B.2.3.2.1 Air Program Compliance. The Paddy's Run Station's air permit is a Part 70 Title V operating permit (Permit No. 130-97-TV) that was issued to LG&E on December 22, 1999. The Part 70 operating permit is in effect for 5 years from the effective date. A renewal application must be submitted at least 6 months prior to the expiration of the permit (December 17, 2004) making a renewal application due to the Air Pollution Control District of Jefferson County on June 17, 2004. According to the 2007 Annual Title V Compliance Certification, LG&E submitted a Title V renewal application on June 11, 2004.

The following items are findings from the document review:

- The existing air emission sources at the Paddy's Run Station include a 19.5 MW natural gas CT (PR11), a 29 MW natural gas CT (PR12), and a 170 MW natural gas CT (PR13).

- EON has submitted a 2007 Annual Air Compliance Certification indicating that it is in compliance with permit conditions, with the exception of a few items. These and other items are noted below in greater detail:
  - Paddy's Run 12 is subject to the federal NO_x Budget Trading Program (40 CFR Part 97). A NO_x Budget Application and Certificate of Representation was submitted as required; however, a monitoring plan and annual NO_x Budget certifications were not submitted as required by the program. In March, EON submitted three letters to the EPA and one to the Air Pollution Control District of Jefferson County for NO_x budget program emission allowance reconciliation, Certification for use of Low Mass Emission Monitoring (LME) Methodology in lieu of CEMS, and the initial monitoring plan for Paddy's Run 12. No information regarding a response from the EPA or the Air Pollution Control District of Jefferson County regarding the acceptance or potential issue due to the oversight was available for review. Additionally, a small discrepancy was noted in this unit's 2007 hours of operation and annual NO_x emissions between the reconciliation letter and the LME letter to the EPA, both dated March 31, 2008.
  - In 2007, EON commissioned an external environmental audit by Murdock, Goldenburg, Schneider, and Groh, LPA (Murdock). The final audit report was issued in March 2007. The results of the audit for air related issues indicated that recordkeeping and reporting requirements related to the conditions of the permit formed the majority of the findings. Murdock was unable to confirm if an operating permit application was submitted after the construction permit (Construction Permit No. 48-00-C) for gas turbine 13 (PR13) which expired on February 28, 2003.
  - Based on the construction permit (Permit No. 48-00-C) and the operating permit (Permit No. 130-97-TV), the facility has an annual NO_x emission limitation of 100 tpy to avoid NO_x RACT and PSD/nonattainment NSR for the facility. Additionally, PR13 cannot exceed 2006 hours during any 12 consecutive months. The 2007 Annual Emission Inventory indicated compliance with these two requirements.

– A review of compliance data available on the EPA Enforcement & Compliance History (ECHO) website shows no current or historical violations of the Clean Air Act for the facility.

B.2.3.2.2 Future Air Compliance Issues. Recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that overall facility compliance is hinged on known regulatory programs as well as these changing regulatory issues. Compliance with these air programs must also be addressed on a program basis and as a combined strategy. Because of the changes in the federal air programs, no attempt in determining how these changes will affect this facility has been made in this report. However, based on a review of the station's documentation, no future plans or facility modifications were identified which would require air considerations.

B.2.3.3 Water.

B.2.3.3.1 Water Supply. Drinking water is supplied by a municipal system. The same municipal water is also used in an evaporative cooler associated with the most recently installed CT. De-ionized water is trucked from Cane Run Station for turbine blade washes. Groundwater from an onsite supply well is used as a source of non-contact cooling water for one of the turbines.

B.2.3.3.2 Water Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if their discharges go directly to surface waters. The EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky.

Paddy's Run has a KPDES wastewater discharge permit (Permit. No. KY0002071) issued by KDEP in 2008 that is effective through June 2013. The permit includes limits for such wastewater discharges as non-contact cooling water, cooler blowdown, and storm water runoff. Limits appear to be typical for small power generation facilities. The permit includes such reporting or monitoring parameters as temperature, flow, and suspended solids.

Black & Veatch reviewed discharge monitoring reports for calendar year 2007. No issues of noncompliance were noted.

B.2.3.4 Solid and Hazardous Waste. Paddy's Run produces general refuse trash and small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.2.3.4.1 General Facility Solid Waste. General solid waste/refuse trash from operations and maintenance at Paddy's Run (including maintenance waste and other nonhazardous waste) is stored onsite in trash compactors and dumpsters before being transferred to a licensed commercial landfill.

B.2.3.4.2 Hazardous Waste. According to the SPCC plan, the Paddy's Run facility is a Conditionally Exempt Small Quantity Generator (CESQG) of hazardous waste. CESQC is defined in Kentucky hazardous waste regulations (401 KAR 30) as a facility that generates less than 220 pounds in any one calendar month and one that accumulates less than 2200 pounds of total waste on site at any time. No hazardous waste compliance issues were noted in documents reviewed.

B.2.3.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulation (40 CFR 112) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters and adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC plans and establishes procedures, methods, and equipment requirements.

The EPA issued revisions to the Oil Pollution Prevention regulation in 2002 that added new definitions and requirements for SPCC plans related to such items as clarification of appropriate secondary containment for tanks and pipelines and including process oil use in the SPCC plan. The EPA has amended the SPCC requirements of the Oil Pollution Prevention regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. Black & Veatch notes that, as of this writing, the latest EPA rules[14] on SPCC Plans require that existing facilities operating prior to August 16, 2002 amend their existing plan to comply with the EPA's regulations by July 1, 2009.

Paddy's Run has a Best Management Practices and Spill Prevention, Control and Countermeasures Plan dated September 2007. This SPCC plan responds to the EPA oil pollution prevention requirements and serves as a best management practices plan as required by the KDEP wastewater discharge permit. Paddy's Run handles thousands of

[14] July 17, 2002, Final Revised SPCC Rule under 40 CFR 112, and May 16, 2007, Final Rule to Extend Deadlines Under SPCC Rule.

gallons of oil products including fuel oil and a variety of transformer oil and lubricants. The largest oil vessel in the SPCC plan is a transformer holding more than 22,000 gallons of oil. The Paddy's Run SPCC plan describes compliance with EPA regulations effective in 2009.

Information provided indicates that no major additional actions and expenses appear to be necessary for oil compliance.

B.2.3.6 Emergency Planning. Under EPA EPCRA regulations, facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year. The form is made available to the public by submittal to state emergency response commissions and the local emergency planning commissions. Black & Veatch reviewed the 2006 Tier II report for Paddy's Run and found the list of chemicals to be typical for power plants.

Paddy's Run does not store ammonia and is not required to have an RMP under the chemical accident prevention provisions (40 CFR 68). Also, EON has determined that Paddy's Run operates below the threshold level for any TRI reporting requirements under EPCRA.

No compliance concerns or expected additional compliance expenses were identified in the Black & Veatch review of the information provided.

B.2.3.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with EON staff.

B.2.3.8 Other Environmental Issues. Observations from Black & Veatch's document review indicated a generally high level of environmental awareness in current and recent operations of the Paddy's Run facility and a proactive approach to environmental management at the facility. Professional environmental staff located at both the nearby Cane Run facility and the company headquarters appear to maintain a systematic approach to ongoing environmental compliance and planning for Paddy's Run.

Otherwise, documents provided by EON did not include studies of any preexisting environmental conditions at the Paddy's Run site (prior to current operations) or additional investigations of known soil/groundwater contamination issues from past operations onsite, and from any historical spills or other previous releases at the site. Such historical contamination issues are typically not subjected to any special requirements at an active power generating facility unless specific local problems have been identified.

No other issues of concern were identified from the review.

B.3 Hydroelectric Generating Plants

B.3.1 Ohio Falls Hydroelectric Generating Station Environmental Review Permit Status & Regulatory Compliance

This environmental review was based on documents provided by EON, and from observations from Black & Veatch staff who visited the facility in July 2008. Authors of the environmental sections did not visit the site. Key documents provided by EON for this review included the following:

- Recent summary of the facility's compliance status from the EPA ECHO database on June 27, 2008.
- LG&E Audit Report, August 6, 2004.
- KDEP KPDES Permit KY0002089, effective July 1, 2008.
- Ohio Falls Discharge Monitoring Reports for 2007.
- LG&E Best Management Practices and Spill Prevention, Control, and Countermeasures Plan, December, 2003.
- Article 404 Federal Energy Regulatory Commission (FERC): Dissolved Oxygen Monitoring Plan.
- Letter dated March 24, 2006, from EON to FERC, confirming compliance with Article 404--Dissolved Oxygen Monitoring Plan.
- FERC order of August 2, 2006, Order Approving Run-of-River Operations Compliance Plan under Article 403.
- FERC order of September 7, 2007, Order Modifying and Approving Recreation Plan under Article 406.
- Letter dated August 23, 2006, from FERC to EON, regarding the Environmental Inspection of the Ohio Falls Project.
- Letter dated April 6, 1998 from FERC to EON establishing annual fees for benefits derived from headwater projects.
- Letter dated April 3, 2001 from FERC to EON establishing annual fees for benefits derived from headwater projects.
- Letter dated April 3, 2002 from FERC to EON establishing annual fees for benefits derived from headwater projects.
- Letter dated April 11, 2003 from FERC to EON establishing annual fees for benefits derived from headwater projects.
- Letter dated April 30, 2004 from FERC to EON establishing annual fees for benefits derived from headwater projects.
- Letter dated June 28, 2007 from FERC to EON establishing annual fees for benefits derived from headwater projects.

- Letter dated May 27, 2008 from FERC to EON establishing annual fees for benefits derived from headwater projects.
- Historic Properties Management Plan for Ohio Falls Hydroelectric Project, prepared by BHE Environmental, Inc., September 21, 2007.
- Letter dated September 1, 2006 from EON to FERC relating to the barge incident at Ohio Falls transmitting the Underwater Inspection Report prepared by their consultant, MHW.
- Disbursement requests from LG&E to FERC dated July 30, 2008 for $136,556.00; July 5, 2008 for $38,569.00; and September 15, 2007 for $635,817.00 for payment of headwater benefits.
- Letter dated May 20, 2008 from FERC to EON stating that an inspection by FERC staff on May 13, 2008 confirmed that the project remains in good operating condition.

B.3.1.1 Current Environmental Compliance.

B.3.1.2 Air. Because there are no applicable air emissions sources at this facility, compliance with applicable air quality regulations is not applicable, and no air permit is required.

B.3.1.3 Water.

B.3.1.3.1 Water Supply. As stated in the BMP/SPCC Plan, all water serving the plant is withdrawn from the Ohio River; the plant has no groundwater wells installed. Potable water for the facility is supplied by the Louisville Water Company. The FERC License authorizes the project's use of water power or surplus water of a government dam.

B.3.1.3.2 Wastewater Discharges. As authorized by the federal CWA, the NPDES permit program controls water pollution by regulating point sources that discharge pollutants into waters of the US. Point sources are discrete conveyances such as pipes or man-made ditches. Industrial, municipal, and other facilities must obtain permits if the discharge directly into surface waters. EPA has delegated the authority to administer the NPDES permit program to the State of Kentucky (KDEP), which oversees the Kentucky PDES (KPDES) program.

Ohio Falls has a KPDES wastewater discharge permit (KY0002089), effective July 1, 2008, and expiring on July 30, 2013. The KPDES permit authorizes the discharge of non-contact cooling water, storm water runoff, sanitary wastewaters, and generator cooling water into the Ohio River. Specifically, the KPDES permit includes numeric limits for effluent from Outfall 001 (non-contact cooling water and storm water runoff) for temperature (31.7° C), and requires reporting of total suspended solids (TSS) and pH. Discharge limits from Outfall 002 (sanitary wastewater) are applied to TSS, total residual chlorine (TRC), and carbonaceous biochemical oxygen demand ($CBOD_5$). Outfall 004 (combining outfalls 004 through 011) authorizes the discharge of generator cooling waters. Quarterly monitoring and sampling are required on all parameters. Limits and parameters appear to be typical for hydroelectric generation facilities.

Black & Veatch reviewed the discharge monitoring reports (DMRs) for calendar year 2007, along with the ECHO Reports mentioned above. No issues of noncompliance were noted in 2007.

The KPDES permit also requires the development and implementation of a BMP Plan. The purpose of the BMP Plan is to prevent or minimize the potential for release of pollutants, via plant site runoff, spills and leaks, or sludge disposal, to surface waters of the US. The facility's BMP Plan is combined with its SPCC Plan, last revised December 2003.

B.3.1.4 Solid and Hazardous Waste. It is likely that Ohio Falls produces general refuse trash (solid wastes). Ohio Falls is a generator of small amounts of hazardous waste as defined in federal and state regulations. Environmental compliance actions are summarized below by general category.

B.3.1.4.1 Solid Wastes. No information regarding generation or disposition of solid waste was provided. It is assumed that the Ohio Falls facility produces general refuse trash and that it is typically stored onsite in dumpsters and hauled offsite by a licensed contractor to an appropriate landfill.

B.3.1.4.2 Hazardous Wastes. The RCRA establishes a cradle-to-grave system for managing the generation, treatment, and disposal of hazardous wastes. Kentucky's requirements for hazardous waste generators are modeled after the EPA's and are found at 401 KAR 32 (Standards Applicable to Generators of Hazardous Waste) for which all hazardous waste generators are required to follow.

The three categories of hazardous waste generators regulated include the following:

- Large quantity generators (LQGs) (generating more than 2,200 pounds of hazardous waste per month);
- Small quantity generators (SQGs) (generating between 220–2,200 pounds of hazardous waste per month); and

- Conditionally exempt SQGs (CESQGs) (generating less than 220 pounds of hazardous waste per month).

LQGs and SQGs are required to obtain a registration ID number; CESQGs are not. According to the EPA ECHO database on August 14, 2008, Ohio Falls is an active CESQG. The specific types of hazardous waste generated at the Ohio Falls facility are not known.

B.3.1.5 Oil Storage and Compliance. Originally published in 1973 under the authority of the federal CWA, the Oil Pollution Prevention regulations (40 CFR 112) set forth requirements for prevention of, preparedness for, and response to oil discharges at facilities storing or using oil in specified threshold amounts. Facilities storing in excess of 1,320 gallons of oil must develop and implement a SPCC Plan. The EPA revised its SPCC regulations in 2002, and extended the compliance dates on May 16, 2007[15]. As of this writing, existing facilities are required to revise their SPCC Plan in compliance with the 2002 regulations, and implement such plan, by July 1, 2009.

Ohio Falls provided a copy of its Best Management Practices and Spill Prevention Control and Countermeasure Plan, revised December 2003. The plant stores diesel fuel, unleaded gasoline, and a variety of equipment oils (lubrication oils, turbine oils, hydraulic fluids, mixed oils, etc.). Chemicals stored include fungicides plus sulfuric acids for battery/backup power use. According to the Material Inventory and Tank List, oil storage is approximately 40,000 gallons. No documentation of spills or spill history was included with the facility information reviewed by Black & Veatch. EON plans to fully comply with EPA's 2002 revisions to its SPCC regulations, included revisions that need to be made to the SPCC Plan, no later than July 1, 2009.

B.3.1.6 Emergency Planning. As required by EPCRA/CERCLA, certain facilities that use or produce hazardous substances, extremely hazardous substances, and toxic chemicals in greater than specified thresholds are subject to a number of requirements, including federal, state, and local reporting requirements.

Sections 302 and 303 of EPCRA require facilities with chemicals designated as extremely hazardous substances (EHS) to work with planning officials to develop comprehensive emergency plans.

Section 304 requires reporting of accidental releases of EHSs.

[15] Additional changes to EPA's SPCC rules are expected when rules proposed on October 1, 2007 become finalized.

Sections 311 and 312 require facilities to provide Material Safety Data Sheets (MSDSs) and chemical inventories of chemicals at their facilities to state and local agencies.

Section 313 of EPCRA requires certain facilities to report on and submit an annual TRI Report to the EPA. These chemicals and chemical categories are listed in 40 CFR Part 372. Submittals continue in the same fashion every year thereafter. The purpose of TRI reporting is to inform local communities of potential hazards associated with TRI chemicals and facilities, and to allow better response should a chemical release occur. Releases governed by the rules include all emissions into the environment including air, water, and land. Facilities are only subject to the provisions of Section 313 if they satisfy all three criteria relating to (1) SIC code classification, (2) hours worked/number of full-time employees at the facility, and (3) use of any of the Section 313 chemicals in amounts greater than threshold quantities specified.

This facility does not store chemicals or have releases that require the filing of TRI reports.

B.3.1.7 Noise. No noise issues were identified in any documents provided by EON or from conversations with facility staff.

B.3.1.8 FERC License Compliance. On October 27, 2005, the FERC issued a new license to LG&E for the Ohio Falls Hydroelectric Project (Ohio Falls) for period of 40 years, effective November 11, 2005, to upgrade, operate and maintain the Ohio Falls Hydroelectric Project. The license is subject to the terms and conditions of the Federal Power Act (FPA), which was incorporated by reference as part of the license, and subject to the regulations the FERC issues under the provisions of the FPA.

Major License Conditions for Ohio Falls and the compliance status of each are discussed below. The numbers refer to specific license conditions:

No. 15 and Article 401: The Secretary of Interior reserves authority to require construction, operation, and maintenance of fishways.

Status: No information regarding requirements for fishways was provided. Black & Veatch assumes that EON has not been requested to construct fishways.

No. 19: LG&E/EON must prepare an Historic Properties Management Plan that will include the conditions recommended by the SHPO.

Status: LG&E has prepared a Historic Properties Management Plan for the Ohio Falls Project. The Plan was prepared by the BHE Environmental, Inc. and Sullebarger Associates, dated September 21, 2007. It included the recommendations of the SHPO.

No. 27: The 1986 agreement with the Corps of Engineers required LG&E to monitor dissolved oxygen (DO) and curtail generation during low DO conditions to enhance the water quality of the Ohio River. Article 404 requires that LG&E develop the DO monitoring plan in consultation with the Louisville District of the COE, the KDEP, and the Oho River Valley Water Sanitation Commission (ORSANCO). On November 22, 2005, FERC granted an extension until March 24, 2006 for EON to file the DO Plan.

Status: LG&E consulted as required with the COE, the KDEP, and ORSANCO. They received comments from both the COE and ORSANCO which were addressed as requested in the final DO Plan. The Plan was filed with FERC on March 24, 2006 as confirmed by transmittal letter from EON to FERC on that date.

No. 28: (1) LG&E must file a plan which will include the parking area and angler access (Article 406); and (2) LG&E must file a plan which will include details on how the turbines at the project could be operated to maximize the opportunity for whitewater boating on the Indiana side of the powerhouse.

Status: On June 11, 2007, LG&E filed a recreation plan in compliance with Article 406 of the FERC license. FERC issued an Order on September 7, 2007 modifying and approving the Recreation Plan under Article 406. The proposed plan will include a parking lot and footpath allowing anglers to have shoreline access to the tailrace area of the Ohio Falls Station. LG&E consulted with both the COE and with the DFWR; neither agency had any objection to the Plan. In its Order of September 7, 2007, FERC specified that EON is not to begin widening the angler access path until the Historic Properties Management Plan required by Article 407 is approved by FERC to insure that no archaeological resources are disturbed.

No. 34: LG&E must reimburse other licensees that improved the headwaters and benefited them (Article 205).

Status: EON provided numerous letters from FERC identifying the amount of the required headwater benefits to be paid in a specific year. Documentation from FERC confirming actual payments of the benefits by EON in 2007 and 2008 was also provided.

No. 35: LG&E can allow only minor activities on the project land (like landscaping) without the permission of the Commission (Article 408). However, all of the activities must still be consistent with the purposes of protecting and enhancing the scenic, recreational, and environmental values of the project.

Article 402: The project shall be operated in run-of-river mode.

Status: Refer to discussion under Article 403 below.

Article 403: The run-of-river mode compliance must be documented; a plan for this must be submitted to the Commission for approval within 90 days of the license.

Status of Articles 402 and 403: On March 24, 2006, LG&E filed a Run-of-River Operations Compliance Plan under Article 403 of the license for the Ohio Falls project. The plan included procedures for coordinating with the Louisville District of the COE to ensure that the COE can meet its flood control and navigation requirements, details on the instrumentation and record keeping used to demonstrate compliance, and details on how the turbines at the project could be operated to maximize the opportunity for whitewater boating on the Indiana side of the powerhouse.

In the plan, LG&E indicated that all communications with the COE will be made via telephone with subsequent email verification. To maximize whitewater boating opportunities and to the extent that operation and maintenance allow, EON will first bring on line those units closest to the Indiana shoreline; these units will also be the last ones taken offline. The flows will be monitored via the use of EON's energy management control system along with meters to measure generation output from each of the generation units. It will also use its Generation Availability Data System to monitor when units are taken off line as requested by the COE due to low water flow and navigational concerns. The Plan also included confirmation of the appropriate consultation with the COE.

On August 2, 2006, FERC issued an Order Approving Run-of-River Operations Compliance Plan Under Article 403 to LG&E.

Article 404: Within 90 days, a plan to monitor the DO level should be submitted to the Commission for approval. The Kentucky DEP and the Corps should be consulted regarding the sufficiency of the plan.

Status of Article 404: Complete. Refer to No. 27 above.

Article 406: Within 1 year, a recreation plan must be submitted to the Commission for approval.

Status: LG&E has prepared a Historic Properties Management Plan for the Ohio Falls Project. The Plan was prepared by the BHE Environmental, Inc and Sullebarger Associates, dated September 21, 2007. It included the recommendations of the SHPO.

Article 407: LG&E shall implement the document for historic preservation listed under requirement 19.

Status: No information regarding implementation has been provided, but the plan was prepared and Black & Veatch assumes that it is being complied with. (Refer to No. 19 above).

Under Section 401(a) of the CWA, FERC may not issue a license authorizing construction or operation of a hydroelectric project unless the state water quality certifying agency either has issued a water quality certification or has waived certification by failing to act on a request for certification within a reasonable period of time, not to exceed one year.

Status: On July 9, 2003, LG&E applied to the KDEP for certification. FERC deemed the certification waived because the KDEP did not act on the application within one year.

B.3.1.9 Other Issues.

2006 Barge Incident

On January 26, 2006, LG&E notified FERC that on that date two barges had impacted the upstream side of the Ohio Falls station. On February 9, 2006, in compliance with FERC regulations Parts 12.10 and 12.13, LG&E filed a written report of the incident with FERC. On April 6, 2006, FERC issued a letter to LG&E agreeing with the conclusions of LG&E's consultant, MWH, and requiring that LG&E submit the final underwater inspection report. MWH prepared a Condition Assessment Report in May of 2006 that was submitted to FERC on September 12, 2006. LG&E has thus satisfied all of FERC's requirements associated with this incident.

2008 Dam Safety Inspection

On May 13, 2008, FERC conducted an operation inspection of Ohio Falls. In a letter dated May 20, 2008, FERC concluded that the facility remains in good operating condition.

B.3.2 Dix Dam Hydroelectric Generating Station Environmental Review Permit Status & Regulatory Compliance

In reviewing the compliance status of the Dix Hydroelectric Project and determining whether the Dix project does or may require a license from the FERC, Black & Veatch reviewed a number of Orders issued by FERC and a legal memorandum prepared for EON. These documents include the following:

- Docket No. UL88-01: Order Finding Hydroelectric Project Jurisdiction (November 19, 1987).
- Docket No. UL88-1: Notice of Withdrawal of Order Finding Hydroelectric Project Jurisdiction issued on November 19, 1987 (December 16, 1987).
- Docket No. EL88-37-0000: Order Denying Petition for Declaratory Order and Denying Motion (December 21, 1988).
- Docket No. EL88-37-001: Order Denying Rehearing (November 26, 1990).
- Memorandum: Procedural History and Current Status of FERC Jurisdiction With Respect to Dix Dam and its Impoundment, Lake Herington, by Kristina Nygaard of Winston & Strawn, LLC directed to Allyson Sturgeon of EON in January of 2007.

Overview

On November 19, 1987, the FERC's Office of Hydropower Licensing (OHL) issued an order finding that continued operation and maintenance of the Dix Hydroelectric Project, which includes the dam's associated reservoir, Lake Herrington, is required to have a FERC license pursuant to Part I of the Federal Power Act (FPA) because the project is located on navigable waters of the United States. For reasons unrelated to navigability, Dix Dam is still unlicensed.

Brief History

In 1922, the Dix River Power Company filed a declaration of intent to construct a dam across the Dix River in Mercer and Garrard Counties Kentucky with the Federal Power Commission (FPC) (later FERC). The FPC determined that no license was required because the project would be above the navigable portion of the Dix River and therefore its construction would not affect the interests of interstate and foreign commerce. Construction of the dam was completed in 1924.

Kentucky Utilities (KU) informally objected to FERC's November 19, 1987 ruling requiring a license, arguing that the Director lacked delegated authority to issue such an order. FERC withdrew the Order on December 16, 1987. In a number of subsequent Orders, FERC rejected KU's argument that FERC lacked authority to require a license, noting FERC is not prevented from finding jurisdiction based on whether the Dix River is navigable at the project location. FERC also stated that, since 1922, decisions by the Supreme Court had refined the definition of navigable under the FPA such that FERC had the authority to reconsider whether a license was required for the continued operation and maintenance of the Dix Hydroelectric Project.

In its Order of 1990, FERC noted that the December 1988 Order did not make findings or determinations as to whether KU is required to obtain a license; it simply held that FERC is not legally precluded from requiring KU to obtain a license. The 1990 Order also did not require KU to take any specific course of action.

According to the Memorandum, the project remains on FERC's list of unlicensed projects to potentially be reviewed at some point, but FERC currently has no plans to revisit the Dix Hydroelectric Project jurisdiction issue. The memorandum also states that typically, a project is moved from the unlicensed list to the "commence investigation list" if state or federal resource agency or an individual requests a jurisdiction review of a project that is believed to be causing significant adverse environmental impacts or is one that raises safety concerns. Until such time as the project is placed on the "commence investigation list" by FERC, the Dix Hydroelectric Project can continue operation without a FERC license.

Appendix C

Fuel Supply and Transportation Contract Summaries

C.1.1 Coal Supply Agreement between KU and Charolais Coal Sales and Phoenix Coal Corporation

Kentucky Utilities Company (KU) entered into an agreement with Charolais Coal Sales, LLC and Phoenix Coal Corporation on August 1, 2007 for the supply of coal. The term ends on December 31, 2009, and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with written permission of the other party.

The quantity of coal to be delivered in each of the three annual periods is listed in the table below:

PERIOD	BASE QUANTITY (TONS)
January 1, 2008 – December 31, 2008	300,000
January 1, 2009 – December 31, 2009	300,000

The base quantity in each period is to be delivered monthly in approximately equal amounts. The delivery term is freight on board (FOB) KU's Green River Generating Station by truck. The source of the coal is 50 percent from the Caterpillarville Mine located in Hopkins County, Kentucky and 50 percent from the Briar Hill Mine located in Muhlenberg County, Kentucky.

The contract price is set firm during five periods. The price per tonnage is listed in the table below:

TONNAGE	PERIOD	($ PER TON)
150,001 – 300,000	January 1, 2008 – June 30, 2008	40.46
300,001 – 450,000	July 1, 2008 – December 31, 2008	40.67
450,001 – 600,000	January 1, 2009 – June 30, 2009	40.42
600,001 – 750,000	July 1, 2009 – December 31, 2009	40.42

Annual adjustments are made based on the price of diesel, iron, and steel scrap. There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price; based on how the actual "As Received" Monthly Weighted Average Btu/lb (AMWA) for coal delivered during a calendar month varies from the minimum Guaranteed Monthly Weighted Average Btu/lb (GMWA). The contracted GMWA is equal to 11,500 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.2 Coal Supply Agreement between KU and Covenant Coal Corporation

KU entered into an agreement with Covenant Coal Corporation on May 1, 2008 for the supply of coal. The term ends on May 31, 2009, and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The approximate quantity of coal to be delivered in each month is 10,000 tons. The total supplied will be approximately 120,000 tons. The coal is to be delivered, FOB KU's Tyrone or EW Brown coal stockpile, by truck. The source of the coal is from the Cowpen No.1 Mine located in Pike County, Kentucky.

The contract price is set firm depending on the delivery station. The price per tonnage is listed in the table below:

STATION	($ PER NET TON)
Tyrone Station	90.30
EW Brown Station	90.50

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,000 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \quad \text{x Price Per Ton} = \quad \text{Per Ton Adjustment}$$

C.1.3 Coal Supply Agreement between KU and ICG

KU entered into an agreement with ICG, LLC on November 11, 2004, for the supply of coal. The term ends on December 31, 2010 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party. The base quantity and the price of coal for the year 2010 are to be negotiated toward the end of the term.

The quantity of coal to be delivered in each of the six annual periods is listed in the table below. The base quantity is to be delivered FOB KU's EW Brown Station coal stockpile by truck and FOB railcar to Kentucky River Loadout near Typo, Kentucky, by train:

PERIOD	BASE QUANTITY (TONS)
2008	400,000 (54,000 min, up to 108,000 tons by truck)
2009	200,000 (54,000 min, up to 108,000 tons by truck)
2010	Re-opener for 2010

The contract price is set firm during the below periods. The price per tonnage is listed for truck and train:

PERIOD	TRUCK ($ PER TON)	TRAIN ($ PER TON)
2008	59.085	43.25
2009	87.835	72.00

Annual adjustments are made based on the price of diesel. There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,000 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.4 Coal Supply Agreement between KU and Little Elk Mining Company, LLC

KU entered into an agreement with Little Elk Mining Company, LLC on August 1, 2005 for the supply of coal. The term ends on June 30, 2009, and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The quantity of coal to be delivered in each of the four annual periods is listed in the table below. The base quantity is to be delivered FOB KU's EW Brown coal stockpile near Burgin, Kentucky by truck and FOB railcar at the Sigmon rail loading facility near Hazard, Kentucky by train. The source of the coal is from Little Elk Mining Company, LLC's Little Elk Mine, from multiple seams, located in Breathitt, Knott, and Perry Counties, Kentucky:

PERIOD	BASE QUANTITY (TONS)
2008	800,000 (108,000 min, up to 216,000 tons by truck)
2009	130,000 (54,000 min, up to 108,000 tons by truck)

The contract price is set firm during the below periods. The price per tonnage is listed for truck and train:

PERIOD	TRUCK ($ PER TON)	TRAIN ($ PER TON)
2008	58.59375	44.59375
2009	61.35	47.35

Annual adjustments are made based on the price of diesel. There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,000 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \quad \text{x Price Per Ton} = \quad \text{Per Ton Adjustment}$$

C.1.5 Coal Supply Agreement between KU and Nally and Hamilton Enterprises, Inc.

KU entered into an agreement with Nally and Hamilton Enterprises, Inc. on May 1, 2008 for the supply of coal. The term ends on December 31, 2011 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party. There is a price review for price negotiation on this contract for the year 2011.

The quantity of coal to be delivered in each of the four annual periods is listed in the table below. The base quantity is to be delivered FOB railcar at the Balkan, Kentucky rail loading facility by train and FOB barge at the dock on the Big Sandy River by barge.

The source of the coal is from mines and facilities located in Knox, Bell, Harlan, Letcher, and Perry Counties, Kentucky; these are owned by Nally and Hamilton Enterprises, Inc.:

BASE QUANTITY (TONS)		
PERIOD	EW BROWN	GHENT
2008	90,000	60,000
2009	180,000	120,000
2010	180,000	120,000
2011	To be negotiated	To be negotiated

The contract price is set firm during the below periods. The price per tonnage is listed by barge and train depending on location:

PERIOD	TRAIN EW BROWN ($ PER TON)	TRAIN GHENT ($ PER TON)	BARGE BIG SANDY RIVER ($ PER TON)
2008	66.00	52.50	62.81
2009	67.00	48.50	58.81
2010	69.00	49.50	59.81
2011	To be negotiated	To be negotiated	To be negotiated

Annual adjustments are made based on the price of diesel. There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,000 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \quad \text{x Price Per Ton} = \quad \text{Per Ton Adjustment}$$

C.1.6 Coal Supply Agreement between KU and Perry County Coal Corporation

KU entered into an agreement with Perry County Coal Corporation on July 1, 2005 for the supply of coal. The term ends on December 31, 2011 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The quantity of coal to be delivered in each of the six annual periods is listed in the table below. The base quantity is to be delivered FOB KU's Tyrone Station by truck.

The source of the coal is from Perry County Coal Corporation mines located in Perry County, Kentucky:

PERIOD	BASE QUANTITY (TONS)
2008	120,000
2009	120,000
2010	120,000
2011	120,000

The contract price is set firm during the below periods. The price per tonnage is listed for truck delivery:

PERIOD	($ PER TON)
2008	66.25
2009	77.50
2010	77.50
2011	77.50

Annual adjustments are made based on the price of diesel. There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,400 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \text{ x Price Per Ton = Per Ton Adjustment}$$

C.1.7 Coal Supply Agreement between KU and The American Coal Company

KU entered into an agreement with The American Coal Company on April 7, 2008 for the supply of coal. The term ends on June 30, 2008 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The contract quantity is to be delivered monthly for a total of 20,000 tons. The base quantity is to be delivered FOB Green River Plant coal stockpile by truck. The primary source of the coal is from Galatia Mine located in Saline County, Illinois.

The contract price is set firm, at $68.68 per net ton, for the duration of the contract.

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 11,800 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \text{ x Price Per Ton = Per Ton Adjustment}$$

C.1.8 Coal Supply Agreement between LG&E and KU, and Patriot Coal Sales, LLC

Louisville Gas and Electric Company (LG&E) and KU entered into an agreement with Patriot Coal Sales, LLC on January 1, 2008, for the supply of coal. The term ends on December 31, 2009 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The quantity of coal to be delivered in each of the two annual periods is listed in the table below. The base quantity is to be delivered FOB the Patriot Dock at Mile Point 31.5 by barge. The source of the coal is from the Patriot Coal Company located in Henderson County, Kentucky; Patriot Coal Company L.P.; Ohio County Coal Company; and Highland Mining Complex located in Union County, Kentucky.

PERIOD	BASE QUANTITY (TONS)
2008	1,250,000
2009	1,250,000

The contract price is set firm during the below periods. The price per tonnage is listed for barge delivery:

PERIOD	($ PER TON)
2008	30.00
2009	31.00

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 10,850 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \quad \text{x Price Per Ton} = \quad \text{Per Ton Adjustment}$$

C.1.9 Coal Supply Agreement between LG&E and KU and Smoky Mountain Coal Corporation

LG&E and KU entered into an agreement with Smoky Mountain Coal Corporation on January 1, 2002, for the supply of coal. The term ends on December 31, 2009 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The quantity of coal to be delivered in each of the remaining periods of the seven-year term is listed in the table below. The base quantity is to be delivered FOB to Sebree Dock Green River, Henderson Riverport Ohio River, or to the constructed dock at Mile Point 45.8 Green River by barge. The source of coal is from geological seam Kentucky No.9, from Cochise's Knob Lick No.9 or Allied Resources, Inc.'s Onton Reserve Mines, Webster County, Kentucky:

PERIOD	BASE QUANTITY (TONS)
2008	950,000
2009	400,000

The contract price is set firm during the below periods. The prices listed are determined by the quality of the shipment:

PERIOD	($)	QUALITY
2008	31.00/ton	C
	30.01/ton	D
2009	35.95/ton	C
	34.87/ton	D

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA.

The contracted GMWA is equal to 11,200 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.10 Coal Supply Agreement between LG&E and KU and Southern Appalachian Coal Sales, Inc

LG&E and KU entered into an agreement with Southern Appalachian Coal Sales, Inc. in April 2008, for the supply of coal. The term ends on December 31, 2009 and does not contain a renewal clause. The agreement contains a termination clause for default of either party. This contract may be assigned with the written permission of the other party.

The quantity of coal to be delivered is one train per month for 18 months for a total of 162,000 to 180,000 tons. The base quantity is to be delivered FOB Resource Loadout at Resource, Kentucky on the CSX Railroad by train. The source of the coal is from B&W Resources Mine located in Leslie County, Kentucky.

The contract price is set firm, at $68.75 per ton, for the duration of the contract.

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,000 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \quad \text{x Price Per Ton} = \quad \text{Per Ton Adjustment}$$

C.1.11 Coal Supply Agreement between LG&E and Alliance Coal, LLC

LG&E entered into a coal supply agreement with Alliance Coal, LLC (Alliance Coal) on December 16, 2005, effective January 1, 2006. The agreement will expire on December 31, 2011 unless otherwise extended to no later than December 31, 2015, subject to early termination if both LG&E and Alliance Coal mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The agreement provides for Alliance Coal to sell and deliver coal via rail and barge to LG&E. LG&E is also purchasing coal from Synfuel Solutions Operating, LLC (SSO) through its Coal Synfuel Supply Agreement dated effective as of January 1, 2002, as amended. Alliance Coal is providing feedstock to SSO in order for SSO to meet its obligations to LG&E. LG&E has no representation, warranty or guarantee to Alliance Coal as to the quantity of coal synfuel that it will purchase or receive; however, Alliance Coal has to reduce its amount of coal deliveries during a particular time period by the amount of coal synfuel that LG&E purchases from SSO via its Coal Synfuel Agreement.

The contract quantities to be delivered for the years 2007 through 2009 are in the ranges of 2.75 through 3. millions of tons per year for the rail nomination and 1.0 through 1.25 millions of tons per year for the barge nomination. For the years after and including 2010, the contract quantities are in the ranges of 2.5 through 3.5 millions of tons per year for the rail nomination and 0.5 through 1.5 millions of tons per year for the barge nomination. If the contract is to be extended beyond 2011, the mutually agreeable rail nomination tonnage range would be determined. If Alliance Coal fails to deliver or LG&E fails to take all of such adjusted base quantity scheduled for a particular year for any reason, the performing party at its sole option may elect for the nonperforming party to make up such undelivered quantities in the calendar year immediately following the calendar year in which undelivered quantities should have been delivered.

Three coal delivery options are available. Delivery Option 1 is delivery of coal via rail from Hopkins County, Webster County Coal, or Pleasant View Mining rail loading facilities. Delivery Options 2 and 3 are via a barge, but Option 2 is from Tow Head Island (THI), which is at or near Mile Point 828 on the Ohio River, and Option 3 is from Sebree Dock (Sebree), which is located at or near Mile Point 43.5 on the Green River. For the years including and after 2009, Option 4 provides for delivery from River View Dock located at or near Mile Point 842.9 on the Ohio River. Option 4 has a delivered coal base price of \$34.86 per ton in the year 2009. Any prices after and including 2010 are to be negotiated by LG&E and Alliance Coal before May 1 of the prior year of purchase.

The base price of the coal to be sold hereunder in the calendar years 2006 through 2009 with respect to each of the FOB Delivery Options are shown below:

Year	Delivery Option 1 FOB Rail (\$ per Ton)	Delivery Option 2 FOB Barge THI (\$ Per Ton)	Delivery Option 3 FOB Barge Sebree (\$ Per Ton)
2006*	1.348	1.411	1.424
2007	32.09	32.48	33.50
2008	32.24	32.51	33.33
2009	33.80	34.21	34.97
*Note: Price in \$ per MBtu.			

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 11,500 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.12 Coal Supply Agreement between KU and Alpha Coal Sales Co., LLC

KU entered into a coal supply agreement with Alpha Coal Sales Co., LLC (Alpha Coal) on September 21, 2006, effective January 1, 2007. The agreement will expire on December 31, 2009, subject to early termination if both KU and Alpha Coal mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The agreement provides for Alpha Coal to sell and deliver coal to KU FOB railcar at Yellow Creek Loadout near Hazard, Kentucky or Roxana Loadout near Whitesburg, Kentucky, on the CSXT railroad.

The contract base quantity to be delivered to KU amounts to 324,000 tons for both the years 2007 and 2008. The base price of the coal to be sold for the years 2007 and 2008 are \$1.76829 per MBtu (\$43.50 per ton). The tonnages, pricing, and other terms and conditions applicable to the period from January 1, 2009 to December 31, 2009 must be negotiated by KU and Alpha Coal. If KU or Alpha Coal fails to perform with respect to supplying or taking delivery of all of such adjusted base quantity scheduled for a particular year for any reason, the performing party, at its sole option, may elect for the nonperforming party to make up such undelivered quantities in the calendar year immediately following the calendar year in which undelivered quantities should have been delivered.

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The contracted GMWA is equal to 12,300 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.13 Coal Supply Agreement between Armstrong Coal Company, LLC and LG&E and KU

LG&E and KU entered into a coal supply agreement with Armstrong Coal Company, Inc. (Armstrong Coal) on December 20, 2007, effective January 1, 2008. The agreement will expire on December 31, 2015, subject to early termination if Armstrong Coal, LG&E, and KU mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The agreement provides for Armstrong Coal to sell and deliver coal to LG&E and KU FOB railcar at the Midway Unit Train Facility rail loadout near McHenry, Kentucky on the Paducah and Louisville Railroad, or FOB barge at the Smallhous Dock at Mile Point 76.6 on the Green River near Centertown, Kentucky.

There are two types of quality of coal to be delivered. The minimum GMWA for Quality 1 is 11,000 Btu/lb, whereas the GMWA for Quality 2 is 11,300 Btu/lb. The annual base quantity to be delivered to LG&E and KU for the year 2008 is 600,000 tons (90,000 tons of which can be Quality 2 coal), for the year 2009, there is to be an amount of 2,500,000 tons (375,000 tons of which can be Quality 2 coal), and for the years after and including 2010 there are to be 4,000,000 tons of coal delivered (600,000 tons of which can be Quality 2 coal). For the year 2010, LG&E and KU have the right to nominate up to 1,500,000 tons of coal to be delivered by rail if LG&E and KU make such nomination in writing to Armstrong Coal by September 1, 2009. For the years after and including 2011, LG&E and KU have the right to nominate up to 2,500,000 tons of coal to be delivered by rail if LG&E and KU make such nomination in writing to Armstrong Coal by September 1 of the preceding year. If KU and LG&E or Armstrong Coal fails to perform with respect to supplying or taking delivery of all of such adjusted base quantity scheduled for a particular year for any reason, the performing party, at its sole option, may elect for the nonperforming party to make up such undelivered quantities in the calendar year immediately following the calendar year in which undelivered quantities should have been delivered.

The base price of coal to be provided to LG&E and KU is based on dollars/ton and determined by the calendar year in which the coal is delivered. Shown below is the contracted price of both qualities of coal scheduled for the years 2008 to 2015:

Year	Quality 1		Quality 2	
	Barge	Rail	Barge	Rail
2008	$27.31	N/A	$28.30	N/A
2009	$27.60	$27.60	$28.76	$28.76
2010	$28.21	$28.21	$29.63	$29.63
2011	$28.36	$28.36	$29.78	$29.78
2012	$28.51	$28.51	$29.93	$29.93
2013	$28.66	$28.66	$30.08	$30.08
2014	$28.81	$28.81	$30.23	$30.23
2015	$28.96	$28.96	$30.38	$30.38

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.14 Fuel Purchase Order between COALSALES, LLC and LG&E and KU

LG&E and KU entered into a fuel purchase order with COALSALES, LLC (COALSALES) on May 13, 2008, effective May 21, 2008. The purchase order will expire on December 31, 2009, subject to early termination if COALSALES, LG&E and KU mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The purchase order provides for COALSALES to sell and deliver coal to LG&E and KU FOB barge at Cora Terminal located at Mile Point 98.5 on the Mississippi River.

The coal is for Mill Creek, Trimble County, and Ghent Stations. The total quantity of coal to be supplied is approximately 200,000 tons for the entire order. 100,000 tons is to be shipped from May 21, 2008 through December 31, 2008 and another 100,000 tons is to be shipped from January 1, 2009 through December 31, 2009. The price set forth for the year 2008 is $57.75 per net ton at 11,000 Btu and $60.00 per net ton at 11,000 Btu for the year 2009.

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \times \text{Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.15 Coal Supply Agreement between COALSALES, LLC and LG&E and KU

LG&E and KU entered into a coal supply agreement with COALSALES, LLC (COALSALES) on May 23, 2006 and last amended on January 14, 2008, effective April 1, 2006. The agreement will expire on December 31, 2009, subject to early termination if COALSALES, LG&E and KU mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The agreement provides for COALSALES to sell and deliver coal to LG&E and KU FOB railcar at the rail loading facility at Somerville North, South, and/or Central rail loadouts near Oakland City, Indiana on the Indiana Southern Railroad and FOB barge at any one or all of the following facilities: the Patriot Dock at Mile Point 31.5 on the Green River (note: Patriot Dock is only used for the 2006 and 2007 years); the Evansville Terminal Dock, at Mile Point 858.3 on the Ohio River; the Caseyville Dock located at Mile Point 871.3 on the Ohio River; the Uniontown Dock at Mile Point 842.9 on the Ohio River; and/or the

Yankeetown Dock at Mile Point 772.5 on the Ohio River (note: the Yankeetown Dock and Uniontown Dock are only used for the years 2008 and 2009).

There are two types of quality of coal to be delivered. The minimum GMWA for Quality A is 10,850 Btu/lb, whereas the GMWA for Quality B is 11,000 Btu/lb. The minimum GMWA for the years 2008 and 2009 is 11,000 Btu/lb for both the rail and barge deliveries.

The base quantities to be sold and delivered by COALSALES for the contracted term are shown below:

Base Quantity (Tons)		
Year	Rail Delivery	Barge Delivery
2006	750,000	187,500
2007	1,027,000	1,000,000
2008	1,000,000	400,000
2009	0	75,000

If COALSALES fails to supply or deliver or KU and LG&E fails to take all of such adjusted base quantity scheduled for a particular year for any reason, the performing party, at its sole option, may elect for the nonperforming party to make up such undelivered quantities in the calendar year immediately following the calendar year in which undelivered quantities should have been delivered.

The base prices of coal to be delivered by COALSALES for the contracted term are shown below:

Base Price ($ per MBtu)			
Year	Quality A - Barge	Quality B - Barge	Quality B - Rail
2006	$1.380	$1.380	$1.273
Base Price ($ per Ton)			
Year	Quality A - Barge	Quality B - Barge	Quality B - Rail
2007	$30.60	$31.02	$28.60
Year	Barge		Rail
2008	$31.60		$29.26
2009	$32.75		To be determined

The minimum GMWA for Quality A is 10,850 Btu/lb where the GMWA for Quality B is 11,000 Btu/lb. The minimum GMWA for the years 2008 and 2009 is 11,000 Btu/lb for both the rail and barge deliveries.

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \text{ x Price Per Ton} = \text{Per Ton Adjustment}$$

C.1.16 Coal Supply Agreement between LG&E, KU, and Charolais Coal

LG&E and KU entered into a coal supply agreement with Charolais Coal No. 1, LLC; Charolais Coal Resources, LLC; and Charolais Coal Sales, LLC (Charolais Coal) on December 21, 2006, effective January 1, 2007. The agreement will expire on December 31, 2010, subject to early termination if Charolais Coal, LG&E and KU mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The agreement provides for Charolais Coal to sell and deliver coal to LG&E and KU FOB barge at Arnon Dock at Mile Point 73.2 on the Green River.

This agreement supersedes LG&E Contract No. LGE05011 between LG&E and Charolais Coal, dated January 1, 2005. LG&E's Contract No. LGE05011 had approximately 600,000 tons remaining to be delivered, which shall be carried over to this agreement at a base price of $29.61 per ton for years 2007, 2008, and 2009.

The base quantity of coal for the year 2008 will be a combination of 200,000 tons (carried over from Contract No. LGE05011) and 500,000 tons (new for 2008), the total of which will be 700,000 tons. The base quantity of coal for the year 2009 will be a combination of 200,000 tons (carried over from Contract No. LGE05011) and 1,000,000 tons (new for 2009), the total of which will be 1,200,000 tons. The base quantity of coal for the year 2010 will be an amount of 1,000,000 tons. If Charolais Coal fails to supply or deliver, or KU and LG&E fail to take all of such adjusted base quantity scheduled for a particular year for any reason, the performing party, at its sole option, may elect for the nonperforming party to make up such undelivered quantities in the calendar year immediately following the calendar year in which undelivered quantities should have been delivered.

The base price for coal for the year 2008 is the weighted average price of approximately 200,000 tons (carried over from Contract No. LGE05011), at a base price of $29.61 per ton and 500,000 tons (new for 2008), at a base price of $34.00 per ton. The base price for coal for the year 2009 is the weighted average price of approximately 200,000 tons (carried over from Contract No. LGE05011), at a base price of $29.61 per ton and 1,000,000 tons (new for 2009) at a base price of $35.00 per ton. The base price for the year 2010 is $36.10 per ton.

There is a monthly adjustment for different levels of ash, moisture, and sulfur in the coal delivered. The price is also adjusted monthly based on actual coal heat content versus assumed delivered heat content. This adjustment is included in the total base price, based on how the actual AMWA for coal delivered during a calendar month varies from the minimum GMWA. The GMWA for the contracted coal to be delivered is 11,500 Btu/lb. The calculation for the per-ton adjustment is as follows:

$$\frac{\text{AMWA - GMWA}}{\text{GMWA}} \text{ x Price Per Ton} = \text{ Per Ton Adjustment}$$

C.1.17 Barge Transportation Agreement between LG&E, KU, and Crouse Corporation

LG&E and KU are counterparties in a barge transportation agreement with Crouse Corporation. The agreement will expire on December 31, 2013, subject to early termination if Crouse Corporation, LG&E, and KU mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The contract provides for Crouse Corporation to load and deliver coal or limestone to LG&E and KU FOB barge at the various contracted loading and delivery points.

The delivery points of coal to LG&E and KU include Mile Point, Mill Creek Station, Can Run Station, Trimble County Station, Ghent Station, and Jefferson County Riverport. The delivery points of limestone to LG&E and KU include Mill Creek, Trimble County, and Ghent.

The rates per ton and adjustments thereof that LG&E and KU pay to Crouse Corporation for the various destination points from different loading points are listed in Section 7 of the Agreement. The rates set forth in Subsection 7(A) in the agreement apply to cargo loaded commenced as of January 1, 2005 and are adjusted each quarter thereafter. Sixty percent (60 percent) of the base rate changes as a result of the percent change from the base PPI Industrial Commodities Index Less Fuels and Related Products and Power found in Table 8 of the Producer Price Indexes, published monthly by the US Department of Labor, Bureau of Labor Statistics (PPI) first published for the agreement term. Twenty-five percent (25 percent) of the base rate changes in proportion to changes in the average price of diesel fuel. Five percent (5 percent) of the base rate changes as a result of changes in taxes. Ten percent (10 percent) of the base rate is fixed.

C.1.18 Railroad Transportation Contract between LG&E and PAL

LG&E entered into a railroad transportation contract with Paducah & Louisville Railway, Inc. (PAL) on March 13, 2006, effective April 1, 2006. The agreement will expire on December 31, 2011, subject to early termination if both LG&E and PAL mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The contract stipulates that PAL provide railroad transportation services and equipment and track necessary for the rail transportation of coal via railcar from Cardinal Mine Station, Cimarron Mine, or Dotikito to LG&E's Mill Creek Plant at Kosmosdale, Kentucky; Cane Run Plant at Louisville, Kentucky; or the Jefferson Riverport at Louisville, Kentucky.

The contracted quantity of coal to be transported for the years 2006 through 2011 amounts to 2,000,000 tons per calendar year. PAL and LG&E also meet no later than April 15 of each year during the term of the agreement to discuss possible increases in volume level for the next calendar year; however, if PAL and LG&E agree upon a volume level greater than 2,500,000 tons, then the volume guarantee must be guaranteed by LG&E for a minimum of 3 years. PAL must deliver loaded trains to LG&E destination(s) by the first 7 a.m. following loading of the train at the mines, provided loading of said train is completed by 3 p.m.

Shown below are the contracted base rates that LG&E agrees to pay PAL for the transportation and delivery of coal from origin points to destination points:

Base Rates ($ per Ton)		
Destination: Mill Creek (Kosmosdale, Kentucky)		
Origin	All Aluminum Trainset	Steel Trainset
Cimarron Mine, Kentucky	$3.46	$3.56
Cardinal Mine, Kentucky	$3.46	$3.56
Dotiki, Kentucky	$4.15	$4.25
Destination: Cane Run or Jefferson Riverport (Louisville, Kentucky)		
Origin	All Aluminum Trainset	Steel Trainset
Cimarron Mine, Kentucky	$3.88	$3.98
Cardinal Mine, Kentucky	$3.88	$3.98
Dotiki, Kentucky	$4.59	$4.69

Included with the base rate is an All-Inclusive Index Less Fuel With Forecast Error Adjustment (AAR Index) that is issued quarterly by the Association of American Railroads. The base AAR Index for the first quarter of 2006 equaled 111.2. This percent change in the AAR Index for each calendar quarter (based on the base AAR Index) is then multiplied by the given base rates to provide new rates for each new quarter within the contracted term. There is also a fuel surcharge applied to every new quarterly rate. The fuel surcharge equals the actual price per gallon minus the base fuel price per gallon quantity times the average fuel usage to move a unit train from PAL-served mines to LG&E's destinations, quantity divided by the tons of coal delivered. These new quarterly rates are what LG&E will have to pay PAL for the transportation and delivery of coal.

If there is a shortfall in the quantity of coal to be delivered each month, there is a shortfall payment included in the contract. If the actual monthly loading quantity is less than the standard monthly loading quantity, then PAL shall invoice LG&E for such shortfall by multiplying the amount of the shortfall (in tons) by the rate (including applicable fuel surcharge, if any) in effect from Cardinal Mine, Kentucky to Kosmosdale, Kentucky, and LG&E will pay such invoice.

C.1.19 Rail Transportation Agreement between KU and CSXT/TTI Railroad

KU entered into a railroad transportation contract with CSX Transportation, Inc. (CSXT) and Transkentucky Transportation Railroad, Inc. (TTI Railroad) on May 12, 2008, effective July 1, 2008. The agreement will expire December 31, 2010, subject to early termination if KU and CSXT/TTI Railroad mutually agree with mutual written agreement or there is a material breach that is not a force majeure. The contract provides that CSXT and TTI Railroad transport coal in joint-line service from Balkan, Kentucky or Brookside, Kentucky to FOB barge at the TTI Terminal in Maysville, Kentucky. The barge then supplies coal to Ghent Generating Station. In addition, TTI Railroad arranges for the transloading by TTI Terminal of the coal to be shipped by LG&E and KU via barge.

The contracted quantity of coal to be transported for the year 2008 amounts to 60,000 net tons from Balkan, Kentucky and 40,000 net tons from Brookside, Kentucky. For the years 2009 to 2010, there are to be 100,000 net tons of coal to be transported from Balkan, Kentucky.

The base rate for the transportation is $10.31 per net ton for CSXT-owned or CSXT-leased open-top cars, and $9.81 per net ton for KU-supplied aluminum rapid discharge coal hoppers with no mileage or per diem payable by CSXT or TTIS. Both base rates include the cost of dumping. Beginning July 1, 2008, the rate will be adjusted quarterly by multiplying a Rail Cost Adjustment Factor (RCAF) by the percentage change from the previous quarter to the current quarter in the RCAF, issued and promulgated by the Surface Transportation Board (STB). In no case shall the rate go below the initial base rate. In addition, HDF Fuel Surcharge Publication 8661 shall be applied to every quarterly rate.

C.1.20 Special Contract for Firm Gas Sales & Firm Transportation Service between Gas Distribution Business of LG&E, Electric Generation Businesses of LG&E and KU

LG&E, on behalf of its Gas Distribution Business, herein referred to as the "Company," has a special contract for Gas Sales and Transportation Service with LG&E and KU, on behalf of their Electric Generation Businesses, collectively referred to as the "Customer," effective as of November 1, 2007. The Customer agrees to purchase firm sales service for a portion of its requirement from the Company. The remaining gas requirement is managed and procured by the Customer but delivered to the Company for firm transportation through the Company's facilities with redelivery to the Customer's electric generation facilities.

The initial term of the agreement is for 1 year and expires on October 31, 2008. After the expiration, the agreement is automatically renewed annually and continues in full force until terminated by either party with a written notice 1 year prior to the effective termination date.

The table below sets the operational parameters applicable to each generation facility through the Texas Gas Transmission pipeline. The maximum hourly rate and maximum daily quantity are for information and planning purposes, because the Company will provide sales and transportation service in excess of the maximum rates and quantities.

Generation Facility	Minimum Delivery Pressure (MDP) Psig	Maximum Hourly Rate (MHR) Mcf/hour	Maximum Daily Quantity (MDQ) Mcf/day	
			Sales	Transport
Cane Run	100	545	13,080	N/A
Mill Creek	100	690	16,560	N/A
Paddy's Run	60	1,800	N/A	43,200
Grand Total	-	3,035	29,640	43,200

The applicable rates and charges for firm sales and transportation service are as summarized in the table below. The sales/transport monthly billing demand is the greater of the sales/transport MDQ, as listed in the table above, or the highest daily volume of gas delivered on any day during the month or during the 11 preceding monthly billing periods.

Description	Rates and Charges	
	Sales	Transport
Monthly Customer Charge per Generation Facility	$68.00	$686.00
Monthly Demand Charge per Mcf	$8.30	$2.43
Distribution Charge per Mcf Delivered	$0.2253	$0.0487
Gas Supply Cost Component per Mcf Delivered	Per IGS Rate*	NA
*IGS Rate – Industrial Gas Service (IGS) Rate Schedule, as amended from time to time by the Company.		

C.1.21 Firm Transportation Agreement between Texas Gas and KU

KU entered into a Firm Transportation Agreement with Texas Gas Transmission, LLC (Texas Gas) effective April 1, 2008; the primary term of this agreement will extend through October 31, 2012. At the end of the term, or any subsequent rollover term, this agreement will automatically be extended for an additional rollover term of 1 year, unless either party terminates this agreement at the end of such primary or rollover term by giving the other party at least three hundred sixty-five (365) days advance written notice prior to the expiration of such primary or rollover term. Texas Gas will deliver natural gas from Texas Gas's Centerpoint-Bosco, Regency-Riverton, or Pan Energy-Perryville locations to KU's Bedford No. 2 delivery point (Latitude 38-33-53, Longitude 85-18-25) in Trimble County, Kentucky.

The contracted quantities to be delivered by Texas Gas are provided by combining pipeline capacity (the nominated portion) and storage capacity (the un-nominated portion) into a single transportation service. The contracted daily quantities to be delivered for the months April, May, and October for each year 2008 to 2010 are 59,000 MBtu/D (59,000 MBtu/D being nominated or un-nominated, with a maximum un-nominated quantity of 177,000 MBtu). The contracted daily quantities to be delivered for the months of June to September for each year 2008 to 2010 are 151,000 MBtu/D (100,000 MBtu/D being nominated quantities, 151,000 MBtu/D being un-nominated quantities, with a maximum un-nominated quantity of 453,000 MBtu). The total entitlement(s) of summer quantity for the years of 2008 to 2010 is 22,021,000 MBtu. The contracted daily quantities to be delivered for the summer season beginning

April 1, 2011 are 151,000 MBtu/D (100,000 MBtu/D being nominated quantities, 151,000 MBtu/D being un-nominated quantities, with a maximum un-nominated quantity of 453,000 MBtu). The total entitlement(s) of summer quantity for the year 2011 is 27,633,000 MBtu.

The contracted daily demand rate for the delivery to the primary delivery point (Bedford No. 2 [Trimble County], Meter No. 1522) or alternate delivery points (Lebanon–Texas Eastern, Lebanon–Dominion, Lebanon–Columbia, LG&E/Meter No. 1529, Midwestern-Whitesville, ANR-Slaughters, Trunkline Gas Company-Dyersburg, Egan, Evangeline, and Iowa) for April 1, 2008 through October 31, 2010 is the lower of $0.3461/MBtu or Texas Gas' maximum tariff rate, and for April 1, 2011 through October 31, 2012 is the lower of $0.4000/MBtu or Texas Gas' maximum tariff rate. The contracted rates for the delivery to the qualified point (Bluegrass Generation) is KU's daily demand rate plus $0.0167/MBtu or an amount that results in KU paying Texas Gas' Maximum Zone 4 SNS Rate. The daily overrun rate is the lower of $0.3673/MBtu for April 1, 2008 through October 31, 2010, and Texas Gas' currently effective Maximum SNS Daily Overrun Rate for April 1, 2011 through October 31, 2012. The hourly overrun rate is the lower of $0.0611/MBtu for April 1, 2008 through October 31, 2010, and $0.0000/MBtu for April 1, 2011 through October 31, 2012. Any negotiated or discount rate agreement, as may be agreed from time to time, shall be set forth separately in writing.

Appendix D

Reagent Supply and Transportation Contract Summaries

D.1.1 Lime Supply Agreement between Chemical Lime Company of Missouri, Inc. and Louisville Gas & Electric Company

LG&E entered into a lime supply agreement with Chemical Lime Company of Missouri, Inc. (Chemical Lime) effective September 1, 2007, and extending through August 31, 2011 unless terminated earlier.

There is no renewal provision for the agreement beyond the current term specified above. The overall agreement may be terminated if either party breaches its terms or conditions and the breach continues for 30 days after written notice from the non-breaching party. In addition to the right to terminate, the non-breaching party may also seek lawful or equitable remediation for the breach. Chemical Lime may also terminate the agreement if LG&E reduces its daily requirements for the product to less than 50 percent of the estimated monthly quantity for unexcused reasons. LG&E has the right to discontinue the slaking services with a one-hundred and twenty (120) day written notice to Chemical Lime. If for any other reason than a force majeure Chemical Lime cannot meet its obligations, LG&E has the right to obtain alternate products from third parties. However, any reduction in needed supply on the part of LG&E will not be considered a breach of the agreement.

Under the terms of this agreement, Chemical Lime will supply LG&E with approximately 96,200 tons per year of lime slurry scrubber reagent for its emission control system at the Cane Run Generating Station. LG&E may elect for its product to be sourced from any of Chemical Lime's six locations in Alabama, Missouri, and Virginia.

The lime slurry will be shipped via pneumatic tank truck. Once it arrives at the Cane Run Generating Station, it will be slaked by Chemical Lime or one of its subcontractors. The lime slurry production process will then be tested to ensure the amount of calcium oxide (CaO) present in the slaking process waste material has been limited to a maximum of 1 percent by weight of product delivered.

For each contract year (September 1 through August 31 of the following year), LG&E will pay a product price and freight price. LG& E might also pay a rail fuel surcharge adjustment, as applicable. The product prices for each contract year are as follows:

Contract Year	Product Price
2007-2008	$66.00/ton
2008-2009	$68.64/ton
2009-2010	$71.39/ton
2010-2011	$74.24/ton

The freight price for the first contract year will be $32.78 per ton and will be adjusted at the beginning of each contract year in accordance with the previous year's base freight price and information gathered from the quarterly unadjusted Rail Cost Adjustment Factor from the Association of American Railroads.

The freight price for each contract year following the first contract year will be calculated using the following formula:

Freight Price = Base Freight Price (Average Quarterly Unadjusted Rail cost Adjustment Factor * Average of the Previous Year's Same Four Quarters)

Monthly rail surcharges will be calculated using average cost in cents per gallon from previous months, information from a pre-calculated rail fuel surcharge table in the agreement, and a percentage monthly weighted average of CaO. Additionally, LG&E will pay a fixed monthly slaking fee to Chemical Lime. This fee will start at $45,483 and escalate 3 percent per year on the anniversary date of the agreement. The slaking fee will be reduced $4,752 per month if certain technological concessions are made.

D.1.2 Limestone Supply Agreement between Mercer Stone Company and KU

KU entered into a limestone purchase agreement with Mercer Stone Company (Mercer Stone), a division of Mago Construction Company, LLC, commencing on June 15, 2007, and continuing through December 31, 2018.

The agreement provides for Mercer Stone to sell and deliver limestone from Mercer Stone's quarry in Harrodsburg, Kentucky to KU's Brown Station. KU will use the limestone as a reagent in one or more of its Brown Station flue gas desulfurization (FGD) systems. The supplied limestone should not contain any extraneous materials such as metal, steel, wood, and extraneous mining materials, nor should it have a shale content of greater than 2 percent. The limestone is to be shipped via truck. Deliveries will be made to KU's Brown Station in accordance with normal Monday through Friday business hours, and all trucks shall conform to the Kentucky Department of Transportation rules and regulations.

Between March 1 and May 1 of 2018, both parties will attempt to negotiate for prices, terms, and conditions to extend the agreement beyond its current term. If the parties cannot reach an agreement, then this agreement will terminate as of December 31, 2018, without liability to either party.

Mercer Stone's failure to comply with Kentucky Department of Transportation rules could result in suspension of the supply agreement. Failure to provide the adequate quality or amount of limestone in a timely manner, or to quickly and effectively address such issues could also be cause for KU to end the agreement. If either party commits a material breach of its obligations, the other party may file notice of its intention to terminate the agreement. Both parties have the right to suspend the agreement in instances of force majeure.

The contracted quantities to be delivered for the year 2009 may range anywhere from zero tons up to a maximum of 250,000 tons annually. For the years 2010 through 2018, the contract quantities may range from a minimum of 150,000 tons up to a maximum of 250,000 tons annually. The limestone will be nominal 1-1/4 inch size (90 percent < 1-1/4, 100 percent < 1-1/2).

The base price of the limestone to be sold hereunder (in the calendar years 2009 through 2018) will be firm during each time period of the agreement and will be determined by the year in which the limestone is delivered, in accordance with the following schedule. An additional $0.25 per ton shall be added to the first 200,000 tons shipped under this agreement.

Year	Base Price	Tonnage Shortfall Amount
2009	$10.12 per ton	Not Applicable
2010	$10.35 per ton	$1.00 per ton
2011	$10.59 per ton	$1.03 per ton
2012	$10.83 per ton	$1.06 per ton
2013	$11.08 per ton	$1.09 per ton
2014	$11.34 per ton	$1.11 per ton
2015	$11.60 per ton	$1.13 per ton
2016	$11.87 per ton	$1.16 per ton
2017	$12.15 per ton	$1.19 per ton
2018	$12.43 per ton	$1.22 per ton

KU will need to pay a tonnage shortfall penalty to Mercer Stone for each ton shortfall less than the above described minimum annual quantities during any calendar year beginning 2010. The applicable tonnage shortfall rates are as listed in the above table. The base prices are subject to adjustment in the event of new applicable federal or state statutes, regulations, or other impositions on the limestone to be supplied, including but not limited to tax increases or decreases. The other acceptable price adjustments are changes to the specifications for limestone size, cleanliness, or associated fuel index pricing. In these instances, an increase of \$0.60 per ton would be added to the base price should KU request an alternate size limestone, and an increase of \$0.50 per ton would be added should KU request clean limestone. The base price is also subject to the following diesel fuel price adjustment calculation:

$$\$0.70 \text{ per ton x } [(DFI_{current}/DFI_{base}) - 1]$$

Where, DFIbase is equal to 199.7, which is the base index equivalent to the arithmetic average of January, February, and March 2006's PPI-Commodities No.2 Diesel Fuel No.WPU057303 indices, and DFIcurrent is equal to the arithmetic average of the last three months' PPI-Commodities No.2 Diesel Fuel No.WPU057303 indices corresponding to January 1, April 1, July 1, and October 1 quarterly adjustment periods starting in 2009.

D.1.3 Limestone Supply Agreement Between Mulzer Crushed Stone Inc. and LG&E/KU

LG&E and KU entered into a Limestone Supply Agreement with Mulzer Crushed Stone Inc. (Mulzer) for the supply of limestone FOB barge to Cape Sandy Dock at Mile Point 647 on the Ohio River or New Amsterdam loading facility at Mile Point 653 on the Ohio River for the supply to KU and LG&E generating stations. The term for the agreement starts on January 1, 2005, and continues through December 31, 2014 subject to price reviews.

Between June 1 and October 1, 2008, both parties will attempt to negotiate for prices, terms, and conditions to be effective beginning January 1, 2009. If the parties cannot reach an agreement, then this agreement will terminate as of December 31, 2008, without liability to either party. If the parties reach an agreement on new prices and/or other terms and conditions, and the agreement is extended to December 31, 2012, then both parties can attempt to negotiate between June 1 and October 1, 2012 for new prices and/or other terms and conditions to be effective beginning January 1, 2013. If the parties cannot reach an agreement, then this agreement will terminate as of December 31, 2012, without liability to either party. Mulzer's failure to deliver, unless it is a force majeure, will constitute a material breach and the agreement can be terminated by LG&E/KU.

There are two limestone sizes specific to the contracted deliveries. Size 1 is limestone of 1-1/4 inch size (100 percent < 1-1/2 inches, 95 percent < 1-1/4 inches) for LG&E and nominal 3/4 inch size (100 percent < 1 inch, 90 percent < 3/4 inch) for KU. Size 2 is limestone of nominal 1 inch size (90 percent < 1 inch) stone to LG&E.

The contracted base price of limestone for LG&E for the year 2008 is $4.70 per ton for Size 1 and $4.88 per ton for Size 2. The contracted base price of limestone for KU for the year 2008 is $4.90 per ton. A quality price discount applies to limestone with less than 90 percent $CaCO_3$. If $CaCO_3$ is less than 90 percent, but greater than or equal to 87 percent, the base price shall be reduced by 2 percent for each 1 percent, or any part thereof, that the $CaCO_3$ is less than 90 percent. If the $CaCO_3$ is 85.5 percent (and LG&E or KU does not reject the shipment), then the base price will be reduced by 10 percent. In addition, there is a fuel surcharge applied every quarter of each contract year. The fuel surcharge is calculated by the actual price per gallon minus the base fuel price per gallon (contracted as $0.75 per gallon) to find the positive change in per-gallon price of fuel. For every $0.10 increase in the cost of fuel, the per-ton fuel surcharge shall be $0.03 per ton.

The contracted base quantity for 2008 is up to a maximum of 1,200,000 tons of limestone to be delivered by Mulzer. The base quantity to be delivered after 2008 will be determined and subject to price review in 2008 and 2012.

D.1.4 Trona Supply Purchase Order between Solvay Chemicals, Inc. and LG&E/KU

LG&E and KU have a Trona Supply Purchase Order with Solvay Chemicals, Inc. (Solvay) for the supply of trona FOB truck to Trimble County and Ghent Generating Stations. The term for the purchase order starts on March 1, 2008 and continues through December 31, 2009. The purchase order will be automatically extended to December 31, 2010 if LG&E/KU notifies Solvay of their intent to purchase up to 35,000 tons of trona for 2010 no later than June 30, 2009. If LG&E/KU makes such election, the product base price and freight charges for 2010 will be determined in the fourth quarter of 2009.

The base price of the trona to be sold hereunder (in the calendar years 2008 through 2009) will be firm during each time period of the purchase order in accordance with the following schedule. The total product price is base price plus freight costs.

Year	Base Price per ton	Freight Bedford	Freight Ghent	Quantity Min tons	Quantity Max tons
2008	$90.00	$89.61 per ton	$88.40 per ton	11,000	14,600
2009	$90.00	To be determined	To be determined	26,000	35,000

Solvay's failure to deliver, unless it is a force majeure, will constitute a material breach, and the purchase order can be terminated by LG&E/KU.

Appendix E

Transmission and Interconnection Contract Summaries

E.1.1 Interconnection Agreement between LG&E and Southern Indiana Gas and Electric Company

The Interconnection Agreement (IA) is between LG&E, and Southern Indiana Gas and Electric Company (Southern Indiana), which is a subsidiary of Vectren Corporation (Vectren).

The IA is effective dated December 1, 1968. This IA has been supplemented and amended multiple times, even as most recently as 1982, with a conformed copy of the IA issued April 23, 1993. In order to terminate the overall agreement, either party must provide thirty (30) months notice in advance. However, different schedules within the IA have different termination agreements. In order to terminate Schedules A-B, F, H, and J-M, either party must provide twelve (12) months notice in advance. In order to terminate Schedule G, either party must provide three (3) months notice in advance. Upon mutual agreement by both parties, the overall agreement may be terminated earlier with at least thirty (30) days' written notice.

The purpose of the IA is to define the terms and conditions for the interconnections between the transmission systems of Southern Indiana and LG&E. The IA governs only the continuity of interconnection, delivery points, metering points, metering equipment, and administrative duties. The schedules within the IA define terms and pricing of various power interchange and transaction services between LG&E and Southern Indiana. The terms and pricing of these services are briefly summarized in the following table.

Schedule	Description	Pricing
A	Emergency energy	Greater of $0.30 per kWh or out-of-pocket cost
B	Economy energy	Price will be negotiated and agreed upon by authorized representatives prior to any transactions involving the delivery and receipt of economy energy. Any third party agreements will be out-of-pocket expenses.
C	Coordination of scheduled maintenance of generating facilities	110 percent of the out-of-pocket cost of the supplying party.
F	Facilities rental, Cloverport Switching Station	Southern Indiana is to pay LG&E $67,112.74 each year plus the applicable percentage factor defined in Schedule F.
G	Fuel conservation power and energy	Demand charge $0.20 per kilowatt of fuel conservation power reserved for each week. Energy charge rate per kWh equal to the out-of-pocket-cost.
H	Southern Indiana power and energy	LG&E to pay demand charge at the specific defined rates outlined in Schedule H. Rates are defined by yearly, monthly, weekly, daily, and hourly maximums.
J	Southern Indiana delivery of third party purchases	LG&E to pay 100 percent of all demand charges charged by third party plus monthly demand charges at the agreed rates.
K	LG&E power and energy	Southern Indiana to pay monthly demand charge at agreed rates.
L	LG&E delivery of third party purchases	Southern Indiana to pay 100 percent of all demand charges charged by third party plus monthly demand charges at the agreed rates.
M	Diversity power	Energy charges to be equal to return of equivalent energy or billed out-of-pocket costs plus up to ten percent. Third party diversity has separate pricing schedule.

The interconnection points (POI) subject to the agreement are as follows, unless the parties agree upon additional new locations:

POI	POI Description
1	"Cloverport POI" At the point LG&E's Cloverport Switching Station, near the town of Cloverport in Breckinridge County, Kentucky, where the terminus of Vectren's 138 kV transmission line connects with LG&E 138 kV facilities.

The parties will operate their facilities in order to provide synchronous operation. Also, the parties will establish an operating committee to coordinate and maintain their generating, transmission, and substation facilities. The operating committee will coordinate the control of time, frequency, energy flow, reactive power exchange, power factor, voltage, and other similar operating parameters to ensure the satisfactory synchronous operation of both parties' transmission systems.

The parties are responsible for operating, maintaining, and testing their own transmission systems and interconnection facilities at the POI in compliance with good utilities practice at their sole expense.

E.1.2 Interconnection Agreement between KU and Big Rivers Electric Corporation

The IA is between KU and Big Rivers Electric Corporation (BREC). This IA provides for wire-to-wire interconnection policies between the respective parties. This IA supersedes an IA entered into by both parties on September 1, 1989 and amended on December 15, 1995.

The IA is effective, based on the effective date of August 1, 2006, for an initial term of one (1) year. After the first year, the agreement will be renewed annually unless either party gives not less than 1 year's prior written notice of such termination. The agreement, however, may be terminated immediately by either party, by written notice to the other, upon such other's violation of any term or provision within the IA, and upon failure to remedy such defect within thirty (30) days or such longer period as applicable law may require.

The purpose of the IA is to define the governing terms and conditions for the wire-to-wire interconnections between the transmission systems of KU and BREC. According to this IA, each party agrees to operate and maintain its transmission system, including all equipment and facilities, in a manner that is consistent with good utility practice. It is the goal of both parties to minimize electrical disturbances and interruption of services. This IA is applicable to the physical interconnection of the transmission systems and interconnection facilities at the POI. The POIs subject to the agreement are as follows:

POI	POI Description
1	"Hardinsburg Interconnection Point." At the point where BREC's 138 kV single-circuit transmission line extending from BREC's Hardinsburg 138 kV Station is connected at KU's Hardinsburg 138 kV Station. The interconnection metering is owned by KU.
2	"Green River Interconnection Point." This point is where BREC's 161 kV single-circuit transmission line extending from BREC's Wilson 345/161 kV Station is connected to the KU Green River 161/138/69 kV Station. The interconnection metering is owned by KU.
3	"Daviess County No.1 Interconnection Point." At the point where BREC's 345 kV single-circuit transmission line extending from BREC's Wilson EHV Stations is connected to the KU Daviess County 345 kV Station.
4	"Daviess County No.2 Interconnection Point." At the point where BR's 345 kV single-circuit transmission line extending from BREC's Coleman EHV Station is connected to the KU Daviess County 345 kV Station.

The execution of the IA is administered by an appointed operating committee consisting of members from both KU and BREC. The committee's principal duties are to establish operating, control, and scheduling procedures. Also, they are required to coordinate maintenance schedules and establish accounting and billing procedures.

Each party is responsible for operating, maintaining, and testing its own transmission systems and interconnection facilities at the POI at its sole expense.

E.1.3 Interconnection Agreement between LG&E and Big River Electric Corporation

The IA is between LG&E and BREC and provides for wire-to-wire interconnections between the parties. The agreement started in the year 1973, for the initial term to December 31, 1985, and is renewable biannually unless or until terminated on such date or on any subsequent December 31 by either party, providing the other at least 24 months' notice of termination.

The purpose of the IA is to define the governing terms and conditions for the wire-to-wire interconnection between the transmission systems of LG&E and BREC. The IA governs the furnishing of mutual emergency and standby assistance, the interchange, sale, and purchase of energy to affect operating economies, the coordination of maintenance schedules of generating and transmission facilities, and the sale and purchase of short-term electric power and energy available on the system of one party and needed on the system of the other.

The POI subject to the agreement is at LG&E's Cloverport Substation, where the 138 kV facilities of LG&E are connected with the terminals of BREC's 138 kV transmission line.

According to the IA, both parties are to operate their facilities in order to provide synchronous operation for three-phase, 60 hertz energy to be delivered at the nominal voltages at the POI. Also, both parties are to establish an operating committee to control the time, frequency, energy flow, power factor, voltage, and other similar matters relating to satisfactory synchronous operation of the transmission systems and interconnection facilities. No party is obligated to either receive or deliver reactive power for the benefit of the other party or when doing so may introduce objectionable operating conditions on the system. Instead, the operating committee will establish voltage levels to be maintained and operating procedures for establishing and maintaining an equitable distribution of reactive power.

Each party is responsible for operating, maintaining, and testing its own transmission systems and interconnection facilities at the POI at its sole expense.

E.1.4 Interconnection Agreement between East Kentucky Power Cooperative and EON

The IA is between EON Services, Inc. (EON) and East Kentucky Power Cooperative, Inc. (EKPC). EON enters the agreement on behalf of LG&E and KU, collectively LG&E/KU.

The IA is effective, based on the effective date of September 1, 2006, for an initial term of ten (10) years. After the tenth anniversary, the agreement will be renewed in successive twelve (12) month periods. In order to terminate the agreement, a party must provide a written notice at least 12 months in advance. The agreement, however, may be terminated earlier upon mutual agreements by all parties and a written notice has been accepted for filing by the Federal Energy Regulatory Commission (FERC).

The purpose of the IA is to define the governing terms and conditions for the wire-to-wire interconnections between the transmission systems of EON and EKPC. According to this IA, each party agrees to operate and maintain its transmission system, including all equipment and facilities, in a manner that is consistent with good utility practice. It is the goal of both parties to minimize electrical disturbances and interruption of services maximizing continuous synchronous operation. The IA is applicable to the physical interconnection of the transmission systems and interconnection facilities at the POIs.

There are 63 POIs subject to the agreement. A detailed list and description of the POIs is in Appendix I of the IA. The 63 POIs consist of voltage levels of 69 kV, 138 kV, and 161 kV. Each POI has a normal status of either "closed" or "open." This designation is listed to maximize performance and operation.

The parties are to establish an operating committee to control the time, frequency, energy flow, power factor, voltage, and other similar matters relating to satisfactory synchronous operation of the transmission systems and interconnection facilities. The committee is also responsible for the rules and standards for testing and calibrating metering equipment.

Each party is responsible for operating, maintaining, and testing its own transmission systems and interconnection facilities at its respective sides of the POI at its sole expense.

E.1.5 Interconnection Agreement among Duke, EON, and Midwest ISO

The IA is among Duke Energy Shared Services, Inc. (Duke), EON, and the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). Duke is acting as agent for The Cincinnati Gas & Electric Company (CG&E) d/b/a Duke Energy Ohio, Inc., and PSI Energy, Inc. (PSI) d/b/a Duke Energy Indiana, Inc. EON is acting as agent for LG&E and KU.

The IA is effective, based on the effective date of March 15, 2007, for an initial term of ten (10) years. After the tenth anniversary, the agreement will be renewed in successive twelve (12) month periods. In order to terminate the agreement, a Transmission Owning Party (TOP) must provide a written notice at least 12 months in advance. Upon drafting an intention to terminate the agreement, the IA will terminate at the end of such twelve (12) month notice period without regard to the expiration of any renewal term. The agreement, however, may be terminated earlier upon mutual agreements by the TOPs and notice to the Midwest ISO.

The purpose of the IA is to define the governing terms and conditions for the wire-to-wire interconnections between the transmission systems of Duke and LG&E/KU. The IA governs only the overall operation and maintenance of the interconnection points between the two systems; it does not govern the transmission services or power sales transactions between the respective parties. The IA is applicable only to the physical interconnection of the transmission systems and interconnection facilities at the POIs. This agreement does not obligate either TOP to provide or receive any service.

The interconnection points subject to the agreement are as follows:

POI	Description
1	At the point where the KU and Duke Energy Indiana Fairview – Ghent 138 kV transmission line is interconnected at the Indiana – Kentucky state line.
2	At the point where the KU and Duke Energy Indiana 345 kV Batesville – Ghent 345 kV transmission line is interconnected at the Indiana – Kentucky state line.
3	At the point where the KU and Duke Energy Indiana 345 kV Speed – Ghent 345 kV transmission line is interconnected at the Indiana – Kentucky state line.
4	At the point in Indiana (approximately 280 feet from the Kentucky-Indiana state line) across the Ohio River from LG&E's Paddy's West Station where LG&E's 138 kV transmission line connects with Duke Energy Indian's 138 kV transmission line extending from R.A. Gallagher Station, near New Albany, Indiana.
5	At the point in Jeffersonville, Indiana where Duke Energy Indiana's Jeffersonville Substation is connected to LG&E's 138 kV transmission line between its Northside Substation near Sellersburg, Indiana and the Beargrass Substation in Louisville, Kentucky.
6	At the point where LG&E's Northside Substation near Sellersburg, Indiana connects to Duke Energy Indiana's 138 kV transmission line from its Speed Substation north of Speed, Indiana.
7	The point near Madison, Indiana where Miami Power Corporation's 138 kV transmission line connects with LG&E's 138 kV transmission line.
8	South of the Ghent – Kenton 138 kV line approximately 1,000 feet east of Interstate 75 in Grant County, Kentucky.

According to the IA, the TOPs shall act and operate their facilities in order to provide synchronous operation consistent with good utility practice. Also, the TOPs shall establish an operating committee. The members of this committee shall be responsible for controlling time, frequency, energy flow, power factor, voltage, and other similar matters relating to satisfactory synchronous operation of the transmission systems and interconnection facilities. The IA states that no TOP shall be obligated to either receive or deliver reactive power for the benefit of the other TOP or when doing so may introduce objectionable operating conditions on the system. Instead, the operating committee will establish: (a) voltage levels to be maintained, and (b) "operating procedures for establishing and maintaining an equitable distribution of reactive power."

Each TOP is responsible for operating, maintaining, and testing its own transmission systems and interconnection facilities at the POI at its sole expense.

E.1.6 Interconnection Agreement between AEP and EON

The Amended and Restated IA is between the American Electric Power Service Corporation (AEP) and EON. AEP is acting as agent for Kentucky Power Company (KPCo), Appalachian Power Company (APCo), and Ohio Power Company (OPCo). EON is acting as agent for LG&E and KU, jointly LG&E/KU.

The IA is effective, based on the effective date of July 1, 2007, for an Initial Term of five (5) years from February 28, 2006. This IA is an Amended and Restated IA to the one dated February 28, 2006 between AEP and EON. After the fifth anniversary from the original date, the agreement will be renewed in successive twelve (12) month periods. In order to terminate the agreement, either party must provide a written notice at least 12 months in advance. Should AEP withdraw its membership from PJM, written notice must be provided to EON. Together, both parties would negotiate an amended agreement or a new IA. However, if an agreement cannot be reached within ninety (90) days, this IA can be terminated.

The purpose of the IA is to define the governing terms and conditions for the interconnections between the transmission systems of AEP and EON. According to this IA, each party agrees to operate and maintain its transmission system, including all equipment and facilities, in a manner that is consistent with good utility practice. AEP and EON will establish an operating committee that will be responsible for the satisfactory operation of the transmission systems and interconnection facilities. This includes establishing accounting and billing procedures, coordinating maintenance schedules, and establishing operating and control procedures.

It is the goal of both parties to minimize electrical disturbances and interruption of services. In coordination for proper system operations, it may be required for each party to share power flow and other information from meters and equipment at a POI. Energy losses on the interconnected facilities will be assigned to the appropriate party based on the interconnected facility metering points or based on procedures set forth by the operating committee.

The points of interconnection subject to the agreement are as follows:

POI	Description
1	"Hillsboro-Kenton Interconnection Point." At the point where AEP's 138 kV single circuit line extends from AEP's Hillsboro 138 kV Station and is connected to EON's Kenton 138 kV Station.
2	"Rodburn Interconnection Point." At the point where AEP's 69 kV single circuit line extends from AEP's Morehead 69 kV Station and is connected to EON's Rodburn 69 kV Station.
3	"Wooten Station Interconnection Point." At the point where AEP's 161 kV single circuit line extends from Wooten Station and is connected to EON's Delvinta-Arnold 161 kV Station.
4	"Clinch River-Virginia City Interconnection Point." At the point where AEP's 138 kV single circuit line extends from AEP's Clinch River 138 kV Station and is connected to EON's Virginia City 138/69 kV Station.

Each party is responsible for operating, maintaining, and testing its own transmission systems and interconnection facilities at the POI at its sole expense.

E.1.7 Independent Transmission Organization Agreement between LG&E/KU and SPP

This Independent Transmission Organization (ITO) Agreement is between LG&E and KU (collectively LG&E/KU), and Southwest Power Pool, Inc. (SPP). SPP is appointed by LG&E/KU to act as the ITO.

The ITO Agreement is effective, based on the effective date of June 1, 2006, for an initial term of four (4) years, after which, each successive subsequent term will be for one-year terms. Mutual agreement by all parties can terminate the agreement at any time. However, either party may terminate the agreement upon 180 days prior written notice. Upon termination of the agreement, the ITO may be required to continue to perform its duties for a transition assistance period of up to 180 days. The cost of services to be performed during this transition period will be negotiated at that time.

LG&E/KU will pay the ITO for the entire initial term, on or before the start of each contract year \$3,340,000 annually. This annual fee accounts for \$390,000 for capital costs and \$2,950,000 in operating costs. Compensation for subsequent terms will be negotiated by the parties in good faith and will be based on the prior year's contract. Should LG&E/KU terminate the agreement early, the ITO is not obligated to refund any amount of money. However, should the ITO or the ITO and LG&E/KU jointly terminate the agreement, an amount will be refunded for the portion of services not rendered.

LG&E/KU and the ITO will each appoint a contract manager that will serve as its primary representative under the agreement. The contract managers will have overall responsibility for managing and coordinating the party's responsibilities. The ITO will work and coordinate reliability planning and operation activities with LG&E/KU's designated reliability coordinator, Tennessee Valley Authority.

The ITO's (SPP) lead responsibilities under this agreement can generally be summarized below.

Function	ITO Function Description
1	All functions and responsibilities of the ITO will be performed by ITO employees or designees of the ITO; the ITOs shall retain full authority and responsibility of these people
2	The ITO will process and evaluate all transmission service requests, transmission and generation interconnection requests. This includes collecting and analyzing all necessary information for the processing and evaluation of such requests
3	Provide analyses and reports on long-term resource and transmission plans for the planning authority area while jointly working with the reliability coordinator
4	The ITO will have ultimate review and approval authority over all planning activities including review and approval authority over transmission plans, development of models, and planning and study criteria
5	Coordinate as necessary with LG&E/KU and its reliability coordinator when processing requests for service into and out of transmission facilities or distribution facilities
6	Independently review data, information, and analyses including facilities studies provided for or performed by LG&E/KU or the reliability coordinator
7	Report in writing to FERC every six (6) months any stakeholders' concerns, and the subsequent ITO's response, and any issues or tariff provisions hindering the ITO from performing its duties

The full functions assigned to the ITO are described in detail in an attachment to LG&E/KU's latest Open Access Transmission Tariff (OATT) document.

LG&E/KU is to remain the owner of its transmission systems and is thus responsible for providing transmission interconnections and services to eligible customers.

The respective parties will own, and continue to own, any and all trade secrets, intellectual property, and processes and designs that were owned prior to entering the agreement. LG&E/KU will provide the ITO all appropriate data required to perform its duties.

E.1.8 Joint Reliability Coordination Agreement among Midwest ISO, PJM, and TVA

The Joint Reliability Coordination Agreement is among and between the Midwest Independent Transmission System Operator, Inc. (Midwest ISO), PJM Interconnection, L.L.C., (PJM), and Tennessee Valley Authority (TVA). This agreement replaced and superseded the Data Exchange Agreement among/between TVA, Midwest ISO, and PJM dated on or about May 20, 2004.

The agreement is dated April 22, 2005. The earliest date that the agreement was expected to be implemented by all parties was June 1, 2005. The agreement has an initial term of ten (10) years and will continue on a year-to-year basis afterward. In order to terminate the agreement, each party must provide a written notice at least 12 months in advance.

This agreement consists of two (2) separate agreements; one is between TVA and Midwest ISO and the other is between TVA and PJM. The purpose of this agreement is to define the management of congestion on transmission system flow gates affected by the power flows among TVA, PJM and/or Midwest ISO transmission systems.

This agreement, including the congestion management process (CMP) it incorporates, provides various procedures for the management of congestion on transmission system flow gates. Midwest ISO, PJM, and TVA will collaboratively seek to improve the CMP to enhance efficiency, reliability, cost-effectiveness, and equity. The agreement also covers the data/information sharing among the parties, protocols of coordinating flow gates and reciprocal coordinated flow gates, and outlines operating protocols for coordinating transmission and generation scheduled outages. The agreement defines emergency operating principles to ensure that the parties will coordinate respective actions to provide immediate relief until the party declaring emergency eliminates the declaration of emergency. Specific voltage and reactive power coordination procedures and transfer limits are also outlined in the agreement.

Under the terms of the agreement, the parties are obligated to establish an operating committee that will meet at least once every quarter to evaluate, monitor, and seek to improve the CMP. A joint planning committee will be formed to prepare and document procedures for developing power analysis models and to conduct a coordinated regional transmission planning study. The parties will coordinate any and all studies required to assure the reliable, efficient, and effective operation of the transmission systems.

According to this agreement, each party will exchange data and information relating to the CMP. Each party agrees to exchange the following types of information and data.

Data	Description
1	Real-time and projected operating data (i.e., generation status of units, transmission line status, real-time loads, real-time constraints, maintenance schedules, forced outage rates, scheduled outage dates, etc.).
2	SCADA data (i.e., transmission power flows, measured bus voltages, status/breaker status, flow and voltage analog measurements, generator output, etc.).
3	Energy management system models (at least once a year).
4	Operations planning data (i.e., flow gates and associated capability data, load forecast, generator data, transmission service reservations, generation/transmission schedules and forced outages, etc.).
5	Planning information and models (i.e., transmission assessment plans for up to the next 10 years, system maps, data for load flow/short circuit/stability cases, etc.).

E.1.9 Reliability Coordinator Agreement between LG&E/KU, and TVA

This Amended Reliability Coordinator Agreement is between LG&E and KU (collectively LG&E/KU) and Tennessee Valley Authority (TVA). TVA is appointed by LG&E/KU to act as its designated Reliability Coordinator (RC).

This agreement was signed and issued on July 19, 2006. The initial term of the agreement is for four (4) years after which, each successive subsequent term shall be for one-year terms. Mutual agreement by all parties can terminate the agreement at any time. However, either party may terminate the agreement upon six (6) months' prior written notice. Upon termination of the agreement, the RC is obligated to continue to perform its duties for a transition assistance period of up to six (6) months.

LG&E/KU will pay the RC the following annual compensations during the initial term:

- Contract Year 1 - $1,397,000.

- Contract Year 2 - $1,439,000.
- Contract Year 3 - $1,511,000.
- Contract Year 4 - $1,586,000.

Compensation for subsequent terms will be negotiated between the two parties and will be based on the previous year's contract. Should LG&E/KU terminate the agreement early, the RC is not obligated to refund any amount of money. However, should the RC or the RC and LG&E/KU jointly terminate the agreement, an amount will be refunded for the portion of services not rendered.

A Reliability Coordination Advisory Committee (RCAC) consisting of representatives of each party will assist the RC in the development of initial and modification of reliability coordination procedures. The RCAC will meet at least twice a year.

Working in conjunction with the RCAC, the RC's prime responsibility is for the reliability of bulk transmission and power supply. This includes reliability analysis, loading relief procedures, ordering curtailment of generation and/or load, and monitoring balancing authority area performance. The RC will perform the following general functions (according to Attachment A of the agreement):

Function	RC Function Description
1	Serving as NERC designated RC and represent TVA reliability area at the NERC and regional reliability council level.
2	Implementing applicable NERC and regional reliability criteria initiatives, such as day-ahead load-flow analysis, transmission loading relief procedures, and information exchange.
3	Developing and coordinating with the RCAC new reliability coordinator procedures and revisions to existing procedures.
4	Exchanging timely, accurate, and relevant transmission information with LG&E/KU, the independent transmission organizations, and with other reliability coordinators.
5	Developing and maintaining system models and tools needed to perform analysis needed to develop operational plans.
6	Coordinating with neighboring reliability coordinators and other operating entities as appropriate to ensure regional reliability.
7	All other reliability coordinator functions as required for compliance with applicable NERC Reliability Standards and regional standards.

Attachment A of the agreement also outlines specific functions of the RC and LG&E/KU's responsibilities related to real-time operations and forward operations.

Another important function of the RC is to work in conjunction with the independent transmission organization (ITO) of the Joint Reliability Coordination

Agreement, and its related congestion management plan, dated April 22, 2005. Jointly, the RC, ITO, and LG&E/KU will work to ensure a long-term plan for reliability, adequate resources, and transmission. Attachment B of this agreement defines the responsibilities between LG&E/KU, the RC, and the ITO. In summary, LG&E/KU will develop an annual plan. The ITO will provide an engineering assessment of the plan and, upon approval, submit the plan to the RC. The RC will perform a regional assessment and resubmit, with the appropriate changes, the annual plan to the ITO for final review and approval.

The respective parties shall own, and continue to own, any and all trade secrets, intellectual property, and processes and designs that were owned prior to entering the agreement. LG&E/KU will provide the RC all appropriate data required to perform its duties.

Appendix F

Power Purchase and Interchange Contract Summaries

F.1.1 Inter-Company Power Agreement with Ohio Valley Electric Corporation

The Inter-Company Power Agreement (IPA) amended and restated as of March 13, 2006 is among Ohio Valley Electric Corporation (OVEC), Appalachian Power Company (Appalachian), Buckeye Power Generation, LLC (Buckeye), Cincinnati Gas & Electric Company (Cincinnati), Columbus Southern Power Company (Columbus), Dayton Power and Light Company (Dayton), FirstEnergy Generation Corp. (FirstEnergy), Indiana Michigan Power Company (Indiana), KU (Kentucky), LG&E (Louisville), Monongahela Power Company (Monongahela), Ohio Power Company (Ohio Power), and Southern Indiana Gas and Electric Company (Southern Indiana). All of the foregoing, other than OVEC, are collectively referred to as the Sponsoring Companies.

It should be noted that OVEC was created in 1953. Therefore, some of the units are quite old. All are coal fired. The agreement terminates on March 13, 2026 or if the generating facilities are disposed of or cease to operate.

The Sponsoring Companies jointly own OVEC; OVEC operates and maintains Ohio Station (more commonly known as Kyger Creek Station), Indiana Station (more commonly known as Clifty Creek Station), and transmission facilities interconnected to the systems of certain Sponsoring Companies. From sources other than the agreement, the total available power from the two stations is about 2200 MW. The minimum generating unit output is 80 MW for each generating unit. Ohio Station consists of five turbo generators and Indiana Station consists of six turbo generators. Total minimum generation is approximately 880 MW. Sponsoring Companies agree to purchase Available Power from the Ohio and Indiana Stations. Available Power is the net kilowatts at 345 kV that OVEC determines the Project Generating Stations will be capable of delivering.

OVEC will make Available Energy available to the Sponsoring Companies in proportion to the participation ratio. No Sponsoring Company shall be obligated to accept any Available Energy. Available Energy will be scheduled using specified procedures.

The power participation ratio applied to each company is listed in the table below.

Company	Participation Percentage
Appalachian	15.69
Buckeye	9.00
Cincinnati	9.00
Columbus	4.44
Dayton	4.90
FirstEnergy	20.50
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	3.50
Ohio Power	15.49
Southern Indiana	1.50
Total	**100.00**

Pursuant to East Central Area Reliability Group (ECAR), OVEC is required to have available spinning reserve equal to a percentage of its internal load as well as supplemental reserve equal to a percentage of its internal load. The supplemental reserve is expected to be provided by the Sponsoring Companies in proportion to their respective power participation ratios above. OVEC transmission facilities are not to be burdened by power and energy flows of any Sponsoring Company to an extent that would impair or prevent the transmission of available power, ECAR or OVEC emergency energy. In supporting OVEC to maintain spinning reserves, the Sponsoring Companies stand ready to purchase from OVEC the energy available from its spinning reserves for their own emergency use or resale to or for another ECAR member which is experiencing emergency.

The Sponsoring Companies pay OVEC for available power and available energy, the charge consists of energy charge, demand charge, transmission charge, emergency energy charge, and minimum loading event costs. The energy charge is determined based on fuel expenses allocable for the supply of available energy multiplied by the billing kilowatt-hours availed to each Sponsoring Company.

The demand charge is equal to the costs incurred by OVEC resulting from its ownership, operation, and maintenance of the generating station and transmission system. Each Sponsoring Company has an unconditional obligation to pay the monthly Demand Charge. Such costs consist of fixed expenses, total operating expenses, taxes, product of \$2.089 multiplied by total shares of capital stock of the par value of \$100 per share of OVEC, employees insurance and pension expenses, and costs that may be incurred for decommissioning of the generating stations.

The transmission charge is equal to the total costs incurred by OVEC for the purchase of transmission service, ancillary services and other transmission related services under the Tariff in the delivery of power and energy to the Sponsoring Companies. Each Sponsoring Company has an unconditional obligation to pay the monthly Transmission Charge.

The emergency energy charge payable to OVEC for ECAR emergency energy supply is 98.74 mills per kilowatt hour plus transmission charges.

The minimum loading event costs occur when one or more Sponsoring Companies fail to take their respective power participation ratio share of the total minimum generating output and the total demand falls below 880 MW.

F.1.2 Interchange Power Contracts between City of Owensboro, City Utility Commission of the City of Owensboro and Kentucky Utilities

The Interchange Power Contract is between the City of Owensboro and the City Utility Commission of the City of Owensboro (collectively referred to as Owensboro Municipal Utilities or "OMU") and KU. The contract was entered into on September 30, 1960 and may extend to year 2020. According to the contract, OMU may terminate the contract without cause upon 4 years' prior notice to KU. KU can terminate with 4 years notice only if the OMU capacity plus reserve margin exceeds 80 percent of the capacity of Station 2. OMU has provided notice of intent to terminate the contract effective May 2010.

OMU owns and operates an electric generating and distribution system at Owensboro, Kentucky. KU owns and operates an electric energy generating and distribution system throughout the Commonwealth of Kentucky and has interconnection with various companies and the TVA. OMU and KU systems are interconnected and integrated.

OMU operates and maintains Station 2 and associated substation facilities (more commonly known as the Elmer Smith Generating Station). The ultimate capacity of Station 2 is 800 MW. OMU has the right to the capacity and energy of Station 2 for resale and sells the remaining to KU. OMU's total load requirement includes Green River Rural Electric Cooperative Corporation's load requirement. Unit No.1 COD was in the 1960s with capacity of about 150 MW and Unit No.2 COD was in the mid-1970s with a capacity of about 250 MW.

KU's net energy from Station 2 is limited to 62 percent of the station output. KU provides backup capacity to OMU, but will not be obligated to provide backup to more than 332.8 MW of the OMU resources.

The capacity and energy costs are distributed between OMU and KU. All capacity cost is allocated monthly in proportion with the generating capacity allocated to each party. Items payable under capacity costs are cost of site acquisitions and constructions bonds, operations costs, replacement costs, estimated amount of capacity costs to cover fuel used for rolling heat, and administrative and general expenses. Fuel cost for rolling heat is $8,900 per month initially based on a fuel cost of 18.2 cents per million Btu. The cost for rolling heat is adjusted monthly based on the actual fuel cost for the month.

Energy cost is based on net kilowatt hours of energy used by each party. Items payable under energy costs are fuel costs, maintenance, materials and labor. Fuel cost is the cost of actual quantity of fuel burned less the fixed (or rolling heat) fuel cost. Not less than 30 days prior to the end of each fiscal year, OMU and KU exchange monthly energy forecasts that each will take for the succeeding fiscal year. OMU is also required each quarter to provide 5 year monthly forecasts to KU.

The OMU capacity cost allocation includes a multiplier to account for reserve margin. The OMU reserve margin factor is determined based on the previous calendar year annual plant Weighted Equivalent Availability Factor (WEAF) as outlined in the below table.

Reserve Margin Factor	
Annual Plant WEAF percent	**Reserve Margin Factor**
78.5 and below	1.2000
78.6 – 79.5	1.1917
79.6 – 80.5	1.1833
80.6 – 81.5	1.1750
81.6 – 82.5	1.1667
82.6 – 83.5	1.1583
83.6 and above	1.1500

All maintenance, materials, and labor expenses are paid by the Maintenance Reserve account, which is funded by OMU and KU. Each party pays the maintenance costs proportional to the each party's energy off-take multiplied by OMU's detailed maintenance costs forecast.

OMU maintains Working Capital Fund, Additions and Replacement Fund, Coal Reserve Fund, and Reserve Sinking Fund sufficient to cover the maximum annual bond interest payment.

According to the 1991 Supplement, KU pays $2.03 per kW per month based on capacity allocation toward decommissioning of Station 2.

F.1.3 Power Purchase Agreement between Dynegy and LG&E/KU

The PPA, entered into on January 28, 2008, is between Dynegy Power Marketing, Inc. (Dynegy) and LG&E and KU, subsidiaries of EON US LLC (the "Buyer"). This agreement is for the sale of electric capacity and energy to Buyer from Unit 1 at Bluegrass Generating Facility. The contract delivery is for two summer periods from June 1 through September 30 in 2008 and 2009. Pursuant to the agreement, Buyer will purchase up to 165 MW of the net capacity and energy, which will be assigned as Designater Network Resource by the Buyer.

The payments are divided into monthly capacity and monthly unit firm energy payments during the delivery periods. The monthly capacity payments for 2008 and 2009 are listed in the table below.

Monthly Capacity Payments		
From	**To**	**Monthly Capacity Payment**
6/1/2008	9/30/2008	$346,500.00
6/1/2009	9/30/2009	$387,750.00

The monthly unit firm energy payments are derived from several components including the delivered unit firm energy, the variable operations and maintenance price (VOM), the fuel cost, and the start charge. The equation to calculate the monthly firm energy payment is as follows: Monthly Unit Firm Energy = (Delivered Unit Firm Energy X VOM) + Fuel Cost + Start Charge

The delivered unit firm energy is the amount of energy in whole MWhs delivered in response to a schedule submitted by Buyer. The VOM component is measured in $/MWh and changes annually according to the table below.

Variable Operations and Maintenance Charge		
From	**To**	**VOM Price ($/MWh)**
6/1/2008	9/30/2008	$2.50/MWh
6/1/2009	9/30/2009	$2.60/MWh

The fuel price is the cost of the natural gas purchased by Dynegy to generate the energy scheduled by Buyer. This excludes all natural gas supplied by Buyer. Fuel usage shall not exceed a heat rate of 10.8 MBtu/MWh at any load level. The quantity of gas required for a successful startup and shutdown shall not exceed 700 MBtu for each scheduled continuous run. Starts that are not successful and that are not solely due to the unexcused failure of Buyer to perform its obligations shall be invoiced and removed from the monthly charges.

The start charge is equal to the number of times that Dynegy completes a continuous run during a monthly billing cycle multiplied by the starts charge listed in the table below:

Unit Start Charge		
From	**To**	**Unit Start Charge - $/Unit – Start**
6/1/2008	9/30/2008	$5,000/Unit - Start
6/1/2009	9/30/2009	$5,250/Unit - Start

Natural gas will be supplied via the Texas Gas Transmission pipeline. Dynegy is responsible for purchasing and causing to be delivered all fuel required utilizing non-firm supply and transportation service to meet its scheduled energy requirements and informing Buyer of the all fuel related charges as soon as they are known. Buyer has a unilateral right to purchase and supply part or all of the required gas to Dynegy to meet the scheduled energy requirements.

Buyer can schedule either 0 MW or 165 MW for each hour during the delivery period with a minimum of hours notice. Buyer may not exceed 1,500 hours per summer period at 165 MW. Buyer will be responsible for taking delivery of energy generated 30 minutes before the start of the schedule and 30 minutes after the end of the schedule to allow for ramp-up and ramp-down of the generating unit. If the delivered power is less than the scheduled power in any month, the monthly capacity payment will be reduced by a percentage of 1 minus the ratio of delivered to scheduled energy.

The schedule specified by Buyer must have a minimum duration of 4 hours with at least 4 hours in between dispatch schedules.

The delivery point for the energy generated will be the interconnection between the Bluegrass Generating facility and the EON transmission system.

Each party is required to provide credit and collateral protection to the other during the term of the agreement. The Fixed Independent Amount is $3,000,000 until September 30, 2008 and $1,500,000 as long as there are obligations under the agreement.

EON

Addendum to 2008 Technical Due Diligence Summary Report (Final Draft)

September 1, 2009

Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, Kansas 66211

BLACK & VEATCH
Building a world of difference.

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1.0 Executive Summary

1.1 Introduction

Black & Veatch Corporation (Black & Veatch) previously issued to E.ON U.S. LLC (EON) a Technical Due Diligence Summary Report (Report) in October 2008, concerning the technical due diligence of EON generating assets in Kentucky. This addendum is issued to provide an update to the Report.

Black & Veatch confirms that, except as stated herein in this Addendum, there has been no material change in the key findings and conclusions previously stated in the Report.

1.2 Scope of Work

To conduct this due diligence review, Black & Veatch provided the following services:

- Reviewed the pertinent status and developments associated with the key findings and conclusions identified previously in the Report.
- Reviewed available documents pertaining to key plant operational, maintenance, performance, and outage data for each facility since July 2008.
- Reviewed available documents pertaining to new environmental issues and environmental compliance at each facility since July 2008, including the following:
  - Notice of violations and documentation related to resolution
  - Internal and external inspection reports
  - Correspondence and meeting memos with environmental agencies
  - Correspondence documenting known compliance issues
  - Information covering legal actions against a facility
  - New/renewal/modified permits
  - Permit applications
  - Environmental compliance reports submitted during the period
  - Updated business plans, related to environmental compliance and control
- Based on the review of the above available documents, prepared an addendum to the Report summarizing the key findings and updates to the Report.

1.3 Due Diligence Scope Clarifications

The goal of the due diligence review for this addendum was to review available documentation and summarize key technical and compliance issues related to the facility from July 2008 through August 2009. Key environmental documents provided by EON for this review are listed in Attachment 1. This due diligence review should not be considered an all-inclusive and comprehensive review/audit consisting of verification of each technical issue or permit condition. Instead, this review provides updates and identifies issues that may be of potential concern since the Report was issued in October 2008. It is possible that other technical or compliance issues exist that were not identified in the documents that were made available for Black & Veatch's review.

In addition, recent changes in federal air regulations associated with mercury, acid mist, $PM_{2.5}$, NO_x, and SO_2 (briefly described in Section 4.0 of the Report) have led to industry uncertainty and clear disruption of air quality planning activities. It is important to note that no attempt was made to update this information or determine how federal air regulation changes will likely affect each generating facility in this addendum.

1.4 General Environmental Review Update

The following paragraphs summarize the general environmental review updates that are related to most or all of EON's generating facilities. Specific environmental review updates that are related to each generating facility are summarized in Sections 2.0 through 5.0.

Ash Pond Status

As a response to a highly publicized spill from a combustion waste pond at a Tennessee Valley Authority facility in Tennessee in December 2008, EON evaluated the status of its Kentucky power station ash ponds. A report issued by ATC Associates (ATC) in February 2009 reported the results of the study for eight ash pond dams defined as having high or moderate failure risk. An additional report was issued by ATC in March 2009 for four additional power station pond dams defined as having low failure risk.

The results of the two ATC reports were included in EON response to the U.S. Environmental Protection Agency (EPA) in a Request for Information under Section 104(e) of Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) as part of a nationwide EPA program to assess existing coal combustion waste impoundments. Also as part of that study, an EPA contractor conducted an impoundment inspection at the Trimble County Station.

The findings of the ATC study indicated that the high and medium risk ash pond were generally in satisfactory to fair condition with some suggested maintenance actions. The low risk impoundments included two dam structures (at Tyrone and at Ghent) evaluated as conditionally poor with recommended high priority deficiencies to be addressed in 2009 or prior to re-use (at Tyrone) of the subject ponds.

Combustion/Coal Byproducts

Combustion of coal at the seven EON generating stations is projected to increase the amount of coal combustion byproducts (CCP) to over 4.7 million cubic yards by year-end 2011, the first full year of operation of the new coal-fired unit at Trimble County. The existing onsite disposal facilities are nearing maximum desired capacity, and long-term disposal of CCP has not yet been fully resolved.

Black & Veatch reviewed EON Comprehensive Strategy for Management of CCP (Strategy) dated June 2009. The Strategy summarizes results of studies undertaken by EON with external experts to evaluate long-term, cost effective, and environmentally responsible CCP management to ensure continued operation of EON units. Options under consideration include construction of onsite CCP management facilities in conjunction with identified beneficial reuse opportunities. The appropriate options that are best suited to a specific facility are still being evaluated.

Oil Storage and Compliance

Revisions to EPA's Oil Pollution Prevention regulation (Regulation) in 2002 added new definitions and requirements for Spill Prevention, Control, and Countermeasure (SPCC) plans related to such items as clarification of appropriate secondary containment for tanks and pipelines. Since 2002, EPA has amended the SPCC requirements of the Regulation to extend compliance dates and clarify and/or tailor specific regulatory requirements. The latest EPA rules on SPCC plans require that existing facilities operating prior to August 16, 2002, amend their existing plan to comply with the EPA's regulations by November 10, 2010. Pending projects at EON facilities related to these rules and described in the Report now have the November 10, 2010 completion deadline (instead of the 2009 deadline noted in the Report).

Additionally EON provided information on the funding and progress of capital projects indicating that all of the pending SPCC and containment related projects will be completed no later than October 2009.

Emergency Planning

Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) requires that certain facilities submit an annual Toxic Release Inventory (TRI) Report to the EPA.

Under OSHA (29 CFR 1910 [Occupational Safety and Health Standards]) and EPA (40 CFR 372 [Toxic Chemical Release Reporting: Community Right-to-Know regulations]), facilities that have hazardous chemicals and that store more than the threshold quantity for any of the chemicals must submit a Tier II Emergency and Hazardous Chemical Inventory Form on or before March 1 of each year. The status of Tier II reporting is noted in the addendum section for each of the facilities for which it is required.

2.0 Coal Fired Generating Plants

2.1 Trimble County Generating Station

2.1.1 Technical Review Update

- Table 2.1-1 shows the 2004 through July 2009 net generation, equivalent availability factor (EAF) and equivalent forced outage rate (EFOR) for Trimble County Unit 1 (TC1). A review of the historical performance indicates that overall TC1 has outperformed industry averages during 2008 and year to date July 2009.
- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at TC1 include:
  - Water wall tube leaks that resulted in a unit shutdown of 116 hours in March 2009, contributing to an EFOR of over 20 percent for the month.
  - Tube leaks on the boiler and superheater that resulted in a unit shutdown of 164 hours in August 2008, contributing to an EFOR of over 16 percent for the month

Table 2.1-1
Historical Performance Data for Trimble County Generating Station Unit 1

	2004	2005	2006	2007	2008	2009 July YTD	Annual Average
Net Generation (MWh)	4,159,138	3,811,260	4,174,883	3,577,340	4,065,036	2,242,799	3,778,383
Equivalent Availability Factor (%)	98.4	88.1	94.3	83.7	95.2	91.2	91.9
Industry Average EAF (%)							*82.9*
Equivalent Forced Outage Rate (%)	0.5	3.0	3.3	4.0	2.7	5.4	3.0
Industry Average EFOR (%)							*7.4*

- TC1's total controllable cost (operating expense, other cost of sales, fuel handling and below-the-line) was above budget by 9.7 percent ($2.1 million) in 2008. Some of this overrun in 2008 was attributable to year round operation of the SCR, which was only budgeted for operation during the ozone season.
- TC1 has not experienced any operational issues or general site access issues associated with the construction of Trimble County Unit 2 (TC2).

- Powder River Basin (PRB) coal will be utilized for TC2 when it enters commercial operation. However, it is unlikely that PRB coal will be burned at TC1.
- The west side boiler slope tubes are scheduled for repairs toward the end of 2009 as part of an EON program to mitigate the risk of waterwall leak issue identified above as a major contributor to forced outages at the facility

2.1.2 Environmental Review Update

Air Program Compliance.

- The Trimble County Generating Station's air permit is a combined Acid Rain, Prevention of Significant Deterioration (PSD) and Part 70 Title V operating permit that expired on June 20, 2008. EON has submitted a renewal application and received a proposed air permit on from KDEP on April 21, 2009 which has the same pollutant emission limits for TC1 as the expired permit. If these emission limits for TC1 are retained in the final permit, it is not likely that any additional air quality controls will be required. In the interim, EON is allowed to continue to operate the station in accordance with the terms and conditions of the expired permit under a permit shield (401 KAR 52:020, Section 12) until a new permit is issued.
- EON has submitted a 2008 Annual Air Compliance Certification indicating that it is in compliance with permit conditions, with the exception of opacity exceedence events. In 2008, 82 opacity exceedence events were reported with the a total duration of 8.2 hours. The total duration of exceedence was only about 0.2 percent of TC1's total operating time. A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.
- The cooling tower associated with TC1 went into service on November 17, 2007. The initial performance test of the cooling tower was deemed invalid by the KDAQ because the unit did not meet the test protocol requirements. A re-test was performed in August 2008 which KDAQ again invalidated and requested another re-test in summer of 2009. The retest has been completed. The results and report are expected to be issued in September.

- Based on a review of Trimble County Generating Station documentation, no future plans or facility modifications affecting TC1 were identified that would require air considerations.

Wastewater Discharge

- The Trimble County Generating Station has a new draft KPDES wastewater discharge permit (Permit No. KY0041971) issued by KDEP on August 4, 2009 for both Units 1 and 2. Key changes from the former permit include the following:
  - Stormwater outfalls 006 through 009 from the previous permit have been removed from the permit and will be managed through the facility's Best Management Practices Plan.
  - As requested by EON, a mixing zone for temperature in the vicinity of the proposed discharge has been defined. KDEP cannot determine a mixing zone for chloride until the chloride sampling data required by Tier 2 reporting requirements is available.
- Black & Veatch did not find any issues of noncompliance in the discharge monitoring reports provided for review. The EPA ECHO Web indicates that the facility was last inspected for Clean Water Act compliance on March 6, 2007 and that there are no current or historical violations of the Clean Water Act for the facility during the past 5 years.

Combustion/Coal Byproducts

- The facility's solid waste landfill permit (Permit #112-00003) requires semi-annual monitoring of production and monitoring wells for a number of constituents, including total dissolved solids, calcium, sodium, and sulfate. The depth to groundwater must also be collected. No exceedances of allowed limits were found in the monitoring results and the groundwater sampling analysis sheets provided for review.
- The existing onsite disposal facilities are nearing maximum desired capacity, and long-term disposal of gypsum byproduct from the FGD process at Trimble has not yet been fully resolved. EON Comprehensive Strategy for Management of Coal Combustion Byproducts (CCP) dated June 2009 indicates that options under consideration include construction of onsite CCP management facilities in conjunction with identified beneficial reuse opportunities. Phased construction of a new landfill at the facility, as well as expansion of the existing ash impoundment and

relining/commissioning the gypsum impoundment, are also being considered. Plans for the new facilities were filed for approval by the Kentucky Public Service Commission in June of 2009.

- The ATC Visual Site Assessment Report from February 2009 indicated the Trimble County Bottom Ash Pond (BAP) dam was in satisfactory condition, with some additional maintenance recommended. Additionally, in July 2009, O'Brien & Gere as a contractor for the EPA, issued a draft report on the condition of the BAP dam as a result of an additional inspection conducted in June 2009. O'Brien & Gere concluded that the BAP "...appears to be in satisfactory condition and is well maintained... (And) the operations and maintenance procedures being practiced at the BAP management unit are adequate, although we recommend additional maintenance procedures be implemented to correct some of the conditions observed."

Hazardous Waste

- The Trimble County Generating Station is a Small Quantity Generator of hazardous waste, defined in federal and Kentucky regulations as 220 to 2,200 pounds generated in one calendar month. The facility's 2008 Hazardous Waste Annual Report Form 1 and its hazardous waste assessment return confirm its Small Quantity Generator status. EPA's ECHO database indicated that an on site Resource Conservation and Recovery Act (RCRA) compliance evaluation was conducted on March 31, 2009 and that no hazardous waste violations or compliance issues were found.

Oil Storage and Compliance

- Trimble County Generating Station Best Management Practices and SPCC plan dated October 2007 complies with the EPA's oil pollution prevention and the KDEP wastewater discharge permit requirements. The SPCC plan must comply with the EPA's regulations by November 10, 2010. EON's report on Generation Major Capital Projects indicates that the oil containment improvements such as the continued use of earthen berms for containment for the large storage tanks and the construction of concrete containment structures for the smaller oil storage facilities for the Station will be completed on or before November 10, 2010.

Emergency Planning

- EON's inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Trimble County Generating Station that are typical for large coal power plants. The 2008 Tier II report for the Station also identified substances typical for large coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

2.2 Mill Creek Generating Station

2.2.1 Technical Review Update

- Table 2.2-1 shows the 2004 through July 2009 net generation, EAF and EFOR for Mill Creek station. A review of the historical performance indicates that overall the facility has performed better than industry averages during 2008 and year to date July 2009.

Table 2.2-1
Historical Performance Data for Mill Creek Generating Station Units 1 to 4

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 1							
Net Generation (MWh)	1,836,791	2,211,426	1,946,526	2,153,807	1,985,134	1,208,007	2,034,092
Equivalent Availability Factor (%)	84.5	94.9	86.5	92.2	85.9	93.4	89.6
Industry Average EAF (%)							*83.9*
Equivalent Forced Outage Rate (%)	5.6	3.7	4.4	3.7	6	4.9	4.7
Industry Average EFOR (%)							*6.7*
Unit 2							
Net Generation (MWh)	2,007,643	1,818,869	2,020,832	1,936,303	2,073,872	1,178,629	1,979,671
Equivalent Availability Factor (%)	92.5	81	90.5	85.7	92.2	93.3	89.2
Industry Average EAF (%)							*83.9*
Equivalent Forced Outage Rate (%)	4.3	6.8	4.5	3.9	4.6	4.6	4.8
Industry Average EFOR (%)							*6.7*
Unit 3							
Net Generation (MWh)	2,286,926	2,956,575	2,827,105	2,793,210	2,989,529	1,451,101	2,723,491
Equivalent Availability Factor (%)	73	91.5	87.8	86.9	93	79.1	85.2
Industry Average EAF (%)							*83.5*
Equivalent Forced Outage Rate (%)	3.7	6	4.5	3.7	3	7.8	4.8
Industry Average EFOR (%)							*6.7*
Unit 4							
Net Generation (MWh)	3,405,217	3,077,144	2,938,797	3,565,870	3321419	2,040,699	3,301,131
Equivalent Availability Factor (%)	90.4	79.3	69	90.8	85.1	91.6	84.4
Industry Average EAF (%)							*82.9*
Equivalent Forced Outage Rate (%)	3.7	17.6	4.5	4.4	6.2	2.9	6.6
Industry Average EFOR (%)							*4.7*

- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at the facility include:
  - Unit 1 experienced 11 days of forced outage events in 2008, and 9 days through July 2009, due to boiler tube failures.
  - Unit 2 was out of service for 7 days in July 2008 for turbine turning gear overhaul in a forced outage.
  - Unit 3 was taken out of service for a four week annual boiler inspection outage in spring 2009.
  - Boiler tube failures caused 10 days of forced outage events for year to date July 2009 at Unit 3. Most of the tube failures occurred at the first re-heater and first super-heater areas.
  - Unit 4 was down for a four week annual boiler outage in April 2008.
  - Unit 4 generator experienced stator windings, voltage control, and liquid cooling system problems that caused 8 days of unplanned outage events in 2008.
  - Unit 4 was down for a planned two week boiler outage in April 2009.
- Mill Creek station total controllable cost for 2008 was $57 million which was approximately 5 percent ($3.1 million) under budget.
- The landfill expansion project required for additional fifteen-year disposal of combustion by-products at Mill Creek is in process with expected completion date of first quarter 2010.
- The Flue Gas Desulfurization (FGD) systems at Mill Creek Units 1 and 2 are planned for refurbishment in 2010-2012 to address the equipment, ductwork, and structural steel nearing their useful lives.
- The capital project to address reagent preparation system capacity issues at the station is included in the plan for 2010-2012.
- An updated capital plan is proposed for boiler reliability improvement to address increased erosion, falling slag corrosion fatigue, and tube wastage; including re-heater and super-heater component replacement as well as water wall weld overlay processes.

2.2.2 Environmental Review Update

Air Program Compliance

- The Mill Creek Station's air permit is a combined, Acid Rain, PSD, and Part 70 Title V operating permit (Permit No. 145-97-TV) that expired in June 2008. EON submitted a renewal application dated November 29, 2007, but a proposed or final permit has not been issued by the Jefferson County Air Quality Agency. In the interim, EON is allowed to continue to operate the station in accordance with the terms and conditions of the expired permit under a permit shield until a new permit is issued.
- A review of the compliance data available on the ECHO website shows that the Mill Creek facility was in non-compliance for three quarters beginning October 2008 through June 2009. Although no details of the violation could be obtained from the documentation provided, the ECHO website does list that the facility is in violation with regard to emissions and procedure (reporting requirements) related to its Title V permit and SIP requirements. The ECHO website also indicates that for the quarter ending June 2009, the facility had emissions and procedural violations (reporting requirements) related to PM and SO_2 emissions, and an emissions and procedural violation of the SIP requirements for the quarter ending December 2008.
- The 2008 Title V compliance report identifies some possible exceptions to compliance related to:
  - Monitoring opacity and PM on Unit 1, Unit 2, Unit 3 and Unit 4.
  - SO_2 and PM emissions standard on Unit 4.
  - Method 5 stack tests reports on Unit 2 and Unit 3 were not reported within 60 days.
- Black & Veatch also reviewed the 2008 TRI report and the 2008 air emissions inventory to check for any inconsistencies between the reported stack emissions in the two reports. A random check of one of the reported pollutants (HCl was checked) indicated no inconsistencies in the magnitude of reported emissions.

Wastewater Discharge

- The Mill Creek Generating Station has a KPDES wastewater discharge permit (Permit No. KY0003221) issued by KDEP in 2002 that expired October 31, 2007. EON submitted a timely renewal application in May 2007, which was deemed complete by KDEP on May 21, 2007. Pursuant to the provision of the expired permit, EON can continue to operate the facility until a new permit is issued.

- Black & Veatch did not find any issues of noncompliance in the discharge monitoring reports provided for review. The EPA ECHO Web indicates that the facility was in compliance with Clean Water Act requirements for the period January to March 2009.

Combustion/Coal Byproducts

- Mill Creek generates bottom ash, fly ash, boiler slag, and FGD solid byproducts (gypsum). If not marketed or beneficially used, the bottom ash and fly ash are placed in an onsite surface impoundment ATB or placed in an onsite landfill. The facility operates under a KDEP Solid Waste Disposal Facility Permit (Number 056-00029). Groundwater monitoring reports revealed no apparent issues.
- The ATC Visual Site Assessment Report from March 2009 indicated the Mill Creek Main Ash Pond dam and the Scrubber Pond dam were in fair condition.
- In August 2008, the US Army Corps of Engineers and the Louisville Metropolitan Sewer District inspected a portion of the Mill Creek Station ash pond embankment that is part of the local flood protection levee. According to EON, the agencies requested action to address an ash pond ditch constructed in the area of the flood protection levee. EON agreed to fill in the existing rim ditch and relocate a new rim ditch away from the immediate vicinity of the levee. This action was completed in 2009 according to information EON provided to the EPA.

Hazardous Waste

- The Mill Creek Generating Station is a Small Quantity Generator of hazardous waste, defined in federal and Kentucky regulations as a facility that accumulates between 220 and 2,200 pounds of total waste in one calendar month. The facility's 2008 Hazardous Waste Annual Report Form 1 and its hazardous waste assessment return confirm its Small Quantity Generator status. EPA's ECHO database reported that an on site RCRA compliance inspection was conducted on May 5, 2009 and no hazardous waste violations or compliance issues were found. In addition, the database reported that there were no incidences of noncompliance for the evaluation period July through September 2009.

Oil Storage and Compliance

- Mill Creek Generating Station's Best Management Practices and SPCC plan dated October 2006 complies with the EPA's oil pollution prevention and the KDEP wastewater discharge permit requirements. The SPCC plan must comply with the EPA's regulations by November 10, 2010.

Emergency Planning

- EON inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Mill Creek River Generating Station that are typical for large coal power plants. The 2008 Tier II report for the Station also identified substances typical for large coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

2.3 Cane Run Generating Station

2.3.1 Technical Review Update

- Table 2.3-1 shows the 2004 through July 2009 net generation, EAF and EFOR for Cane Run station. A review of this historical performance indicates that overall the facility has operated below industry averages during 2008 and year to date July 2009.
- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at the facility include:
  - Unit 4 induced draft booster fan shaft (fan 4A) was replaced during an unplanned three week maintenance outage in February 2009.
  - Unit 4 experienced 9 days of forced outage events associated with boiler tube failures in 2008.
  - In early 2008, Unit 5 was out of service for just under two months for major turbine overhaul.
  - In August of 2008, Unit 5 turbine was shut down for one month due to unplanned repair of the generator collector rings.

Table 2.3-1
Historical Performance Data For Cane Run Generating Station Units 4, 5, and 6

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 4							
Net Generation (MWh)	810,896	1,049,049	959,912	1,102,772	1,040,428	530,316	978,695
Equivalent Availability Factor (%)	77	89	85.9	93.6	89.2	84.1	86.5
Industry Average EAF (%)							*86.3*
Equivalent Forced Outage Rate (%)	5.9	7.3	4.8	2.7	4	3.2	4.7
Industry Average EFOR (%)							*6*
Unit 5							
Net Generation (MWh)	894,036	1,087,989	1,086,066	1,041,442	883,496	580,833	998,124
Equivalent Availability Factor (%)	76	89.2	84.9	84.7	76.2	88.4	83.2
Industry Average EAF (%)							*84.8*
Equivalent Forced Outage Rate (%)	9.7	3.2	4.8	8.4	14.5	1.9	7.1
Industry Average EFOR (%)							*6.2*
Unit 6							
Net Generation (MWh)	1,508,847	1,537,931	1,529,165	1,392,397	1,477,446	809,385	1,472,217
Equivalent Availability Factor (%)	89.9	84.2	85.6	76.7	82.2	82.9	83.6
Industry Average EAF (%)							*85*
Equivalent Forced Outage Rate (%)	4	7.4	4.8	13.2	12.5	8.4	8.4
Industry Average EFOR (%)							*5.9*

- Unit 5 experienced 5 days of forced outage events in 2008 associated with super-heater leaks.
- Unit 6 was taken out of service due to boiler tube failures for 11 days of forced outage events in 2008. Boiler tube issues also caused 10 days of forced outage events, and 14 days of maintenance outages, through July of 2009. Station personnel had identified several boiler components for replacement in 2009-2010 to mitigate this problem.
- Unit 6 experienced a 9 day forced outage in April 2008 due to high pressure turbine bearings issue. This turbine experienced high sub-synchronous vibration at No. 1 bearing that prevented operation in the range of 60 to 85 percent of full load operation. A turbine overhaul scheduled for 2009 that should address the issue has been postponed until spring 2010 as several bearings were reconditioned in 2009.

  - Unit 6 experienced 8 days of outage associated with wet scrubber issues in 2008. EON is presently evaluating capital projects in the near future for FGD system life extension and improvements.
- Cane Run station total controllable cost for 2008 was $47 million which was approximately 2.5 percent ($1.2 million) under budget.
- The Cane Run units FGD systems will be rehabilitated as part of EON's mid and long term capital plans.
- EON is developing the necessary facilities to handle Can Run station combustion by-products; projects are included in the mid and long term capital plans. Bottom ash capacity was previously estimated at 1-2 years, and fly ash at 4-5 years, based on the existing pond and landfill site levels.
- Cane Run station has a boiler circuit strategy and is managing mid-term capital project plans for boiler reliability improvement. The plan includes component replacement based on condition assessment.

2.3.2 Environmental Review Update

Air Program Compliance.

- The Cane Run Station's air permit is a combined Acid Rain, PSD, and Part 70 Title V operating permit (Permit No. 175-00-TV, Revision 1) that expired October 30, 2007. EON submitted a renewal application dated April 27, 2007, but a proposed or final permit has not been issued by the Jefferson County Air Quality Agency. In the interim, EON is allowed to continue operating the station in accordance with the terms and conditions of the expired permit under a permit shield until a new permit is issued.
- The 2008 Annual Air Compliance Certification dated April 15, 2009 indicated that:
  - There were some recorded deviations from the opacity limit for Unit 4, which were reported in the quarterly excess emissions reports. A timely submittal of an excess emission report associated with an upset condition report required for October 8, 2008 was not made, and a PM Method 5 stack test was not reported within 60 days.
  - Unit 6 had some possible exceptions from compliance with the SO_2 limits. Timely submittal of an initial notification report associated with an upset condition that resulted in excess SO_2 emissions was not made, and a PM Method 5 stack test was not reported within 60 days.

- A review of compliance data available on the EPA ECHO Web site indicated that the Cane Run facility was out of compliance for three quarters beginning October 2008 through June 2009. Although no specific details of the violation could be obtained from the documentation provided, the ECHO website indicated the facility is in violation with regard to emissions and procedures (reporting requirements) related to its Title V permit and SIP requirements. For the quarter ending June 2009, the facility had SO_2 emissions and procedural violations of visible emissions.

Wastewater Discharge

- Black & Veatch found only one possible issue of noncompliance in the discharge monitoring reports provided for review. The limit for total residual oxidants was originally reported at a level over the permit limit in July 2008, but a corrected report filed in August 2008 showed the values to be in compliance. The EPA ECHO online report on August 18, 2009 indicates that the facility received a letter of violation/warning on November 25, 2008, possibly related to the July 2008 report. No other items related to noncompliance were noted.

Combustion/Coal Byproducts

- Cane Run station received a Notice of Violation (NOV) from KDEP on February 6, 2009 associated with the incorrect statistical analysis of groundwater data and abandonment of monitoring wells without prior approval. The KDEP reviewer noted trends in groundwater monitoring results, including significant increases in more recent data over the historic data values. The reviewer also noted ongoing discussions between the facility and KDEP on the status of the present groundwater assessment, and mentioned plans to discuss possible changes in the groundwater monitoring plan to resolve this issue.
- The ATC Visual Site Assessment Report from February 2009 indicated that the Cane Run Ash Pond dam was in satisfactory condition.
- The existing onsite disposal facilities are nearing maximum capacity, and long-term disposal of bottom ash, fly ash, and fixed calcium sulfite byproducts at Cane Run has not yet been fully resolved. EON Comprehensive Strategy for Management of Coal Combustion Byproducts (CCP) (Strategy) dated June 2009 indicates that options under consideration include proceeding with Phase I onsite landfill development

plans and executing an offsite option with Louisville Underground, LLC for economically beneficial reuse opportunities. Plans for the new facilities were filed for approval by the Kentucky Public Service Commission in June of 2009.

Hazardous Waste

- The Cane Run Station is a Small Quantity Generator of hazardous waste, defined in federal and Kentucky regulations as 220 to 2,200 pounds generated in one calendar month. The facility's 2008 Hazardous Waste Annual Report Form 1 and its hazardous waste assessment return confirm its Small Quantity Generator status. EPA's ECHO database indicated that a RCRA non-financial record review was conducted February 12, 2009 and that no hazardous waste violations or compliance issues were found.

Emergency Planning

- EON inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Cane Run Station that are typical for large coal power plants. The 2008 Tier II report for the Station also identified substances typical for large coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

2.4 Ghent Generating Station

2.4.1 Technical Review Update

- Table 2.4-1 shows the 2004 through July 2009 net generation, EAF and EFOR for Ghent Generating Station. A review of the historical performance indicates that overall the facility has performed close to industry averages during 2008 and year to date July 2009.

Table 2.4-1
Historical Performance Data for Ghent Generating Station Units 1 to 4

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 1							
Net Generation (MWh)	3,304,417	3,488,619	3,374,404	2,915,043	3,598,899	1,506,055	3,210,532
Equivalent Availability Factor (%)	84.7	87.8	89.4	72.6	89.9	71.1	83.6
Industry Average EAF (%)							*82.9*
Equivalent Forced Outage Rate (%)	3	4.6	3.5	7.9	6.3	16.4	
Industry Average EFOR (%)							*7.4*
Unit 2							
Net Generation (MWh)	2,843,658	2,762,178	3,013,392	3,454,216	2,804,097	1,132,509	2,803,164
Equivalent Availability Factor (%)	92.8	81.1	86.5	90.7	78.4	61.1	81.8
Industry Average EAF (%)							*82.9*
Equivalent Forced Outage Rate (%)	1.3	3.9	3.5	3.8	12.4	6.5	5.2
Industry Average EFOR (%)							*7.4*
Unit 3							
Net Generation (MWh)	2,829,972	3,086,506	2,967,905	2,358,308	3,262,152	1,982,551	2,983,917
Equivalent Availability Factor (%)	89	90.8	86.1	63.5	85.52	94.1	84.8
Industry Average EAF (%)							*82.9*
Equivalent Forced Outage Rate (%)	1.6	1.7	3.5	14.9	8.3	3.2	5.5
Industry Average EFOR (%)							*7.4*
Unit 4							
Net Generation (MWh)	3,088,747	3,249,370	2,852,022	3,232,661	2,840,532	1,776,198	3,051,374
Equivalent Availability Factor (%)	94.1	93	85.2	92.8	75.13	93.2	88.9
Industry Average EAF (%)							*82.9*
Equivalent Forced Outage Rate (%)	0.3	1.5	3.4	8	4	4.3	3.6
Industry Average EFOR (%)							*7.4*

- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at the facility include:
  - In January 2009, Unit 1 was down for a two week forced outage event due to problems with turbine intercept valves. The root cause of the outage was determined and EON implemented appropriate repairs at the unit to resolve the problem.
  - During February 2009 Unit 1 was down for a four week planned annual boiler inspection.
  - Unit 1 experienced a one week forced outage in July 2009 due to electrostatic precipitator problems.

- In July 2008, the Unit 2 cooling tower collapsed and resulted in four weeks of forced outage hours. This tower was budgeted for maintenance overhaul as a capital project in the plan period 2010-2012 but the event resulted in acceleration of the overhaul schedule for Unit 2 cooling tower. The remaining cooling towers at Ghent are included for capital overhaul in the plan period 2009-2012.
- Unit 2 experienced over two weeks of planned and forced outage hours in 2008 associated with Electrostatic Precipitator (hot-side ESP) work and opacity issues.
- Unit 2 was out of service in March 2008 for a four week boiler inspection.
- Unit 2 was taken off line in the spring of 2009 for a scheduled ten-week outage for to tie in new FGD system.
- Unit 3 was taken down for two weeks of maintenance in June 2008 to install a modified design of blade control on the new ID fans associated with the FGD installation. These ID fans were previously unreliable due to blade control issues. Since the installation of the modified design, only a one-day maintenance outage was reported for ID Fans through July 2009 which indicates that reliability of the ID fans has improved significantly.
- Since the beginning of 2009, Unit 3 has experienced five days of forced outages associated with first superheater leaks or slagging.
- Unit 4 was down for two months for major turbine overhaul in the spring of 2008.

- Ghent station total controllable cost for 2008 was $53.9 million which was approximately 2.3 percent ($1.3 million) under budget.
- All four Ghent units are now equipped with new FGDs that were commissioned within the last 18 months.
- The existing combustion byproduct storage capacity is estimated to be exhausted by 2013. EON has plans in the mid and long term capital budget periods to address this issue.
- EON has plans to install new ID fans with the modified design of blade control in 2010 to alleviate unit de-rating associated with original ID fan reliability issues.
- EON has allocated capital in 2010-2012 for significant boiler component replacement to address known issues of slag fall, erosion damage, and fireside corrosion, some of which is attributed to fuel switching.

2.4.2 Environmental Review Update

Air Program Compliance.

- On March 19, 2009 EPA issued an NOV to EON for PSD violations associated with Sulfuric Acid Mist (SAM) emissions increases due to the previous installation of the SCR systems on Unit 1, Unit 3, and Unit 4. The NOV could potentially subject EON to EPA enforcement action that could include civil penalties. However, the NOV also provides EON the opportunity to confer with EPA to resolve the NOV. Details of any resolution of this NOV were not available in the list of documents provided for review.
- A letter of warning was issued by the KDAQ on August 6, 2008 for fugitive airborne emissions of particulate matter (PM) beyond the premises of origin. The letter required EON to develop a compliance plan for preventing airborne PM from being emitted beyond the property boundary. EON addressed this issue and prepared a compliance plan which was submitted on August 15, 2008. The compliance plan requires EON to better manage the water sprinkler system on the coal piles, increase the frequency of monitoring, and address fugitive dust emissions beyond the premises of origin.
- EON has submitted a 2008 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions (and other regulatory programs such as Acid Rain and Risk Management Planning) with the exception of a few items.
    - Unit 2 was in compliance except for five 3-hr SO_2 exceedances in 2008 caused by fuel problems. Opacity exceedances totaled 0.75 percent of operating time.
    - Unit 4 was in compliance except for opacity exceedances, which totaled 1.03 percent of operating time and three 3-hour SO_2 exceedances. The opacity exceedances were mainly due to start-ups, shut-downs, load changes, blowing, precipitator trouble, and unit trip/upset.
- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

Wastewater Discharge

- Black & Veatch found no issues of noncompliance in the discharge monitoring reports provided for review. The EPA ECHO online report on August 18, 2009 also indicates no issues of noncompliance.

Combustion/Coal Byproducts

- The ATC Visual Site Assessment Report from February 2009 indicated as follows for the Ghent ash dams:
  - Ash Treatment Basin (ATB) 1 - Fair condition
  - ATB 2 - Satisfactory
  - Gypsum Stack - Satisfactory
  - Sediment Pond - Conditionally poor
- The sediment pond is currently characterized as a low hazard dam, with the suggestion from the consultant that repairs should be completed in 2009.
- The existing onsite disposal facilities are nearing maximum capacity, and long-term disposal of bottom ash, fly ash, and gypsum at Ghent has not yet been fully resolved. EON Comprehensive Strategy for Management of Coal Combustion Byproducts dated June 2009 indicates that options under consideration include the Trans Ash, Inc. offsite gypsum reuse option and construction of the first phase of an onsite landfill. Plans for the new facilities were filed for approval by the Kentucky Public Service Commission in June of 2009.

Hazardous Waste

- The Ghent Station is a Small Quantity Generator of hazardous waste, defined in federal and Kentucky regulations as 220 to 2,200 pounds generated in one calendar month. The facility's 2008 Hazardous Waste Annual Report Form 1 and its hazardous waste assessment return confirm its Small Quantity Generator status. EPA's ECHO database, dated August 18, 2009, indicated no issues with RCRA compliance.

Emergency Planning

- EON's inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Ghent Station that are typical for large coal power plants. The 2008 Tier II report for the Station also identified substances typical for large coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

2.5 E.W. Brown Generating Station

2.5.1 Technical Review Update

- Table 2.5-1 shows the 2004 through July 2009 net generation, EAF and EFOR for E.W. Brown station steam units. A review of this historical performance indicates that overall the facility has operated below industry averages during 2008 and year to date July 2009.

Table 2.5-1
Historical Performance Data for E.W. Brown Generating Station Units 1, 2 and 3

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 1							
Net Generation (MWh)	568,432	563,532	480,534	493,483	513,921	162,127	482,972
Equivalent Availability Factor (%)	90.1	91.2	89.8	77.6	74.8	89.7	85.5
Industry Average EAF (%)							*84.4*
Equivalent Forced Outage Rate (%)	3.8	3.2	3.5	5.4	16.4	16.1	8.1
Industry Average EFOR (%)							*6.9*
Unit 2							
Net Generation (MWh)	971,532	1,075,007	956,008	1,013,933	1,074,881	339,616	945,593
Equivalent Availability Factor (%)	90.3	87.8	89.4	91.9	94.2	62.5	86.0
Industry Average EAF (%)							*86.3*
Equivalent Forced Outage Rate (%)	2.7	2.5	3.5	2	3.5	8.5	3.8
Industry Average EFOR (%)							*6*
Unit 3							
Net Generation (MWh)	2,246,620	1,584,997	2,031,288	2,396,909	2,534,659	952,131	2,071,116
EAF (%)	85.9	54.4	88.8	85	87.5	69.6	78.5
Industry Average EAF (%)							*83.5*
EFOR (%)	1.2	32.3	4	2.9	6.3	10.9	9.6
Industry Average EFOR (%)							*6.7*

- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at the facility include:
  - Unit 1 generator exciter commutator and brushes caused 11 days of forced outage time in February 2009.
  - In 2008, Unit 1 experienced 7 days of forced outage events due to ESP issues, plus an additional 16 days of planned outage event to

resolve the issues. No further ESP outage issues at Unit 1 were experienced in 2009 year to date through July.

- Unit 1 was taken off line for a four week annual boiler inspection in the fall of 2008.
- In February 2009 Unit 2 had an eight week major turbine overhaul outage.
- Unit 3 was out of service for 20 days in spring of 2008 for planned maintenance of the coal mills.
- Unit 3 was shut down for 6 weeks in spring of 2009 for boiler inspections.
- Unit 3 experienced 11 days of forced outage associated with the generator exciter in June-July of 2009. The station has proposed a capital budget plan to rewind this generator in 2011-2012.

- E.W. Brown station total controllable cost for 2008 was $23.1 million which was approximately 0.3 percent ($0.06 million) over budget.
- The FGD project construction appears to be on schedule. The new FGD will be installed as a common system for all three steam units.
- EON recently started engineering for the installation of a new Selective Catalytic Reduction (SCR) system for Unit 3 to reduce nitrogen oxides (NO_X). The plan calls for construction to start in 2010.
- EON is in the implementation phases of a 20 year combustion byproduct disposal plan for E.W. Brown. The plan will involve expansion of the existing ash pond in three phases, construction of a new 56 acre auxiliary ash pond (this is complete and in service), installation of a liner in the original ash pond (2011-2015), and raising the height of the ash pond berms approximately 60 feet over the next 12 years.
- Unit 1 and Unit 3 generators and associated systems have exhibited recent forced outage events. EON have included capital projects in the 2010-2012 capital plans to rewind Unit 3 generator. The Unit 2 generator rewind project is currently proposed in the long term plan. Unit 1 generator rewind project may be considered for inclusion in the plan based on further condition assessment.

2.5.2 Environmental Review Update

Air Program Compliance.

- EON was issued two NOVs in 2006. These NOVs were issued because the E.W. Brown facility failed to obtain the appropriate permits

(Prevention of Significant Deterioration and Title V) and follow certain other regulatory programs such as the New Source Performance Standards (NSPS) prior to executing major capital expenditures for Unit 3 to increase the unit output to 446 MW.

- EON and the EPA entered into a consent decree on March 17, 2009 and this case has been settled. The consent decree requires EON to comply with a variety of emissions requirements which include the installation of a SCR to control NO_x emissions from Unit 3 no later than December 31, 2012 and a FGD system for controlling SO_x emissions by December 31, 2010. The consent decree also prohibits EON from selling or trading or netting any NO_x and SO_x emission reductions achieved as a result of the implementation of pollution control equipment on Unit 3, except as provided by the consent decree.
- The ECHO website also indicates a summary of this consent decree and lists that a $1.4 million federal civil penalty was imposed. The total compliance action cost is listed as $147 million.
- The Settlement Information Sheet listed on the EPA's Civil Enforcement website lists that under the settlement, EON will spend approximately $135 million to install state-of-the-art pollution control technology for the reduction of SO_2 and NO_x. EON will also surrender 53,000 SO_2 allowances shortly after entry of the consent decree and annually will surrender any excess NO_x allowances resulting from the installation and operation of SCR. EON will pay a $1.4 million civil penalty and expend no less than $3 million in environmentally beneficial projects.
- On June 26, 2009 EON filed an application for a Certificate of Public Convenience and Necessity (CPCN) and Approval of its 2009 compliance plan for the purpose of recovering costs of new pollution control equipment of Unit 3 through its Environmental Surcharge Tariff. An approval of the CPCN application is required to begin the construction of the SCR unit on Unit 3 in 2010 to meet the December 31, 2012 deadline. EON has requested and is hoping to receive the CPCN approval by December 23, 2009.
- On July 9, 2009 EON filed a PSD air permit application for the modification to the facility's PSD/Title V Permit (V-03-023) for the installation of SCR and a SO_3 mitigation system on Unit 3. This application included a detailed BACT analysis of SO_3 (in the form of sulfuric acid) mitigation technologies and concluded that BACT for SO_3

emissions is sorbent injection along with the coincidental use of a wet FGD. The capital and annual operational costs associated with the SO_3 mitigation equipment are expected to be $5.5 million and $2.1 million, respectively with an overall cost-effectiveness of $1,190 per ton of sulfuric acid mist removed.

- EON has submitted a 2008 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions (and other regulatory programs such as Acid Rain and Risk Management Plans) with the exception of a few items. These items are noted below in greater detail:
  - Units 1-3 were in compliance except for numerous opacity and opacity trigger levels throughout the year. The report indicates that the requirement for stack tests were not triggered. The opacity exceedances were mainly due to startups, shutdowns, load changes, blowing, precipitator trouble, and unit trip/upset.

Wastewater Discharge

- Black & Veatch found no issues of noncompliance in the discharge monitoring reports provided. The EPA ECHO online report on August 18, 2009 indicates no issues of Clean Water Act noncompliance since 2006.

Solid Waste: Combustion/Coal Byproducts

- The ATC Visual Site Assessment Report from February 2009 indicated the E.W. Brown Ash Pond Auxiliary dam and the Main Ash Pond dam were in satisfactory condition.
- The existing onsite disposal facilities are nearing maximum capacity, and long-term disposal of bottom ash, fly ash, and future FGD system byproducts at E.W. Brown has not yet been fully resolved. EON Comprehensive Strategy for Management of Coal Combustion Byproducts dated June 2009 indicates that options under consideration include the construction of the second phase of the impoundments (auxiliary impoundment and ash treatment basin). Plans for expansion of the facilities were filed for approval by the Kentucky Public Service Commission in June of 2009.

Hazardous Waste

- The E.W. Brown Station is a Small Quantity Generator of hazardous waste, defined in federal and Kentucky regulations as 220 to 2,200 pounds generated in one calendar month. The facility's 2008 Hazardous Waste

Annual Report Form 1 and its hazardous waste assessment return confirm its Small Quantity Generator status. EPA's ECHO database indicated that a RCRA compliance evaluation inspection was conducted onsite March 6, 2009 and that no hazardous waste violations or compliance issues were found.

Emergency Planning

- EON's inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the E.W. Brown Station that are typical for large coal power plants. The 2008 Tier II report for the Station also identified substances typical for large coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

2.6 Green River Generating Station

2.6.1 Technical Review Update

- Table 2.6-1 shows the 2004 through July 2009 net generation, EAF and EFOR for Green River Generating Station. A review of the historical performance indicates that overall the facility has performed close to industry averages during 2008 and year to date July 2009.

Table 2.6-1
Historical Performance Data for Green River Generating Station 2 Units

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 3							
Net Generation (MWh)	334,589	336,673	206,046	420,678	379,545	123,672	314,923
Equivalent Availability Factor (%)	88.3	86.4	87.4	94.8	88.7	85.9	88.6
Industry Average EAF (%)							*86.1*
Equivalent Forced Outage Rate (%)	5.5	8.4	6	3.6	7	22.6	8.9
Industry Average EFOR (%)							*7.9*
Unit 4							
Net Generation (MWh)	464,247	338,730	433,665	576,042	582,590	234,830	466,307
Equivalent Availability Factor (%)	80.8	53.6	85.9	86.8	91.6	84.8	80.6
Industry Average EAF (%)							*84.4*
Equivalent Forced Outage Rate (%)	6.7	45.3	6	4.8	7.1	7.1	12.8
Industry Average EFOR (%)							*6.9*

- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at the facility include:
  - Unit 3 experienced 13 days of forced outages due to boiler tube failure events in 2008.
  - Unit 3 underwent a planned two week minor boiler outage in May 2008. EON have been performing boiler assessment inspections and generating a prioritized list of issues. The repairs resulting from this report have contributed to the increase in availability of both boilers. Tube shielding projects continue on both boilers during outages.
  - Unit 3 experienced a 14 day forced outage in January 2009 due to a problem with the turbine main stop valves.
  - Unit 3 experienced a 10 day outage event related to ID fan motors in April 2009.
  - Unit 4 underwent a planned 5 day minor boiler outage in September 2008.
  - Unit 4 underwent a planned three week boiler outage in May 2009.
- Green River station total controllable cost for 2008 was $10.3 million which was approximately 2.8% ($0.29 million) under budget.
- According to EON, Green River station is included in the long term plan and integrated resource planning (IRP). However, its forecast net generation is reduced for 2009 due to regional economic downturn and market conditions. Accordingly, the capital project budget for the year has been pared back appropriately. Because of its age and size, the station could be challenged to perform close to industry averages due to its lower capital allocation priority compared with other coal facilities owned by EON.

2.6.2 Environmental Review Update

Air Program Compliance.

- EON has submitted a 2008 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions with the exception opacity exceedance issues. EON indicated Unit 3 and Unit 4 had 147 and 47 opacity exceedances, respectively, due to unit upset, load change, or unit startup. The total opacity exceedance durations were less than 0.5 percent of the operating time for each unit, respectively.

- Black & Veatch also reviewed the 2008 TRI report and the 2008 air emissions inventory to check for any inconsistencies. A random check of the reported pollutants indicated an inconsistency in the magnitude of reported emissions. The facility-wide stack emissions of HCl are reported as 280.88 tons in the annual emissions inventory and 90.95 tons in the TRI report.
- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility.

Wastewater Discharge

- The Green River Generating Station has a wastewater discharge permit (Permit No. KY002011) that expired on October 31, 2004. EON submitted a timely renewal application in April 2004, which was deemed complete by KDEP on August 16, 2004. Green River continues to operate under the provisions of the expired permit.
- Black & Veatch did not find any issues of noncompliance in the discharge monitoring reports provided for review. The EPA ECHO Web indicates that the facility was in compliance with Clean Water Act requirements for the period July 2007 to March 2009. EPA conducted the most recent onsite compliance evaluation on 3/6/07 and reported that no Clean Water Act violations were found.

Solid Waste: Combustion/Coal Byproducts

- Green River generates bottom ash, fly ash and boiler slag. Coal ash is accumulated in an ash pond for subsequent reuse. For basins which are under the 401 KAR 45:060 Kentucky special waste permit-by-rules, the only monitoring requirements are the requirements from the KPDES permit.
- The ATC Visual Site Assessment Report from March 2009 indicated the Green River Main Ash Pond dam and the Scrubber Pond dam were in fair condition.

Hazardous Waste

- The Green River Generating Station is a Conditionally Exempt Small Quantity Generator of hazardous waste, defined in federal and Kentucky regulations as a facility that accumulates less than 220 pounds in any one calendar month and less than 2,200 pounds of total waste on site at any time. EPA's ECHO database reported that an on site RCRA compliance inspection was conducted on November 18, 2008 and no hazardous waste violations or compliance issues were found. In addition, the database reported that there were no incidences of noncompliance for the evaluation period July through September 2009.

Oil Storage and Compliance

- Green River Generating Station's Best Management Practices and SPCC plan dated October 2006 complies with the EPA's oil pollution prevention and the KDEP wastewater discharge permit requirements.

Emergency Planning

- EON's inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Green River Generating Station that are typical for large coal power plants. The 2008 Tier II report for the Station also identified substances typical for large coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

2.7 Tyrone Generating Station

2.7.1 Technical Review Update

- Table 2.7-1 shows the 2004 through year to date July 2009 net generation, EAF and EFOR for Tyrone Generating Station. A review of the historical performance indicates that overall the facility has performed below industry averages during 2008 and year to date July 2009.

Table 2.7-1
Historical Performance Data for Tyrone Generating Station Unit 3

	2004	2005	2006	2007	2008	2009 July YTD	Average
Net Generation (MWh)	238,303	355,762	253,848	390,188	355,632	24,005	272,481
Equivalent Availability Factor (%)	74.8	87.6	87.1	86.1	84.3	93.6	85.6
Industry Average EAF (%)							*86.1*
Equivalent Forced Outage Rate (%)	9.6	4	6	3.9	9.3	39	12.0
Industry Average EFOR (%)							*7.9*

- The significant major outage events that resulted in a unit shutdown of more than 5 days since January 2008 at the facility include:
  - In early 2008, the unit was shut down for one month for coal mill overhaul work.
  - The unit experienced five days of forced outages in 2008 associated with the governor and main steam stop valves.
  - Tyrone 3 was off line in February 2009 for 10 days due to an issue with the circulating water pumps.
- Tyrone station total controllable cost for 2008 was $5.2 million which was approximately 5.5% ($0.3 million) under budget.
- In March 2009, EON decided to mothball the unit for due to regional economic downturn and market conditions. Current plans for this unit include a brief restart for the continuous emissions monitoring system relative accuracy testing (CEM RATA) in 2010. EON currently forecasts that the unit would be placed back in service in 2011.

2.7.2 Environmental Review Update

Air Program Compliance

- A review of compliance data available on the EPA ECHO Web site shows no current or historical violations of the Clean Air Act for the facility, however, the ECHO website indicates there were three non-compliance quarters and the facility has been classified as a High Priority Violator (HPV). No further information on the type and nature of violations is provided. This classification is possibly related to the November 26, 2008 NOV issued by the KDEP related to particulate matter compliance issues at the facility. All parties have apparently agreed upon a resolution and the KDEP forwarded an Agreed Order for signature and EON consent on July 30, 2009. A signed Agreed Order was not available for review. The unsigned Agreed Order stipulated a $20,000 civil penalty payable within 30 days after the signing of the Agreed Order. The unsigned Agreed Order states that EON has implemented remedial measures for the particulate matter non-compliance issues and a stack test conducted on June 27, 2008 indicated compliance with the particulate emissions limits that were previously exceeded. The information about the NOV and subsequent compliance demonstration testing was consistent with the information included in the 2008 Annual Air Compliance Certification.

- EON has submitted a 2008 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions with the exception of a few opacity exceedances. The report indicates Unit 3 had opacity exceedances less than 0.01% of the unit's annual operational time. The exceedances were attributed to load change and unit trip/upset.
- Black & Veatch also reviewed the 2008 TRI report and the 2008 air emissions inventory to check for any inconsistencies. A random check of the reported pollutants indicated a slight inconsistency in the magnitude of reported emissions. The facility-wide stack emissions of HCl were reported as 104.98 tons in the annual emissions inventory and 144.45 tons in the TRI report. While the numbers are not consistent, both are below the emission limit.

Wastewater Discharge

- Black & Veatch found no issues of noncompliance in the discharge monitoring reports provided. The EPA ECHO online report of August 18, 2009 indicates no issues of noncompliance with the Clean Water Act since February 2008.

Solid Waste: Combustion/Coal Byproducts

- The ATC Visual Site Assessment Report from March 2009 indicated the Tyrone Ash pond dam was in poor condition. The ash pond is currently characterized as a low hazard dam, with a suggestion that repairs should be completed before the Tyrone station is placed back in service from its current mothball status, or before any of the beneficial reuse ash previously excavated from the pond is placed back into the pond.

Hazardous Waste

- The Tyrone Generating Station is a Conditionally Exempt Small Quantity Generator (CESQG) of hazardous waste. CESQC is defined in Kentucky hazardous waste regulations (401 KAR 30) as less than 220 pounds generated in any one calendar month and less than 2200 pounds of total waste is accumulated on site at any time. No hazardous waste compliance issues were noted in documents reviewed. The EPA ECHO database indicates no violations or compliance issues.

Emergency Planning

- EON's inventory of chemicals used onsite in its 2009 TRI submission identified types and amounts of listed toxic materials (primarily byproducts of coal combustion) released to the environment by annual operations at the Tyrone Station that are typical for coal power plants. The 2008 Tier II report for the Station also identified substances typical for coal power plants. Black & Veatch did not identify any compliance concerns or expected additional compliance expenses associated with these reports.

3.0 Combustion Turbine Plants

3.1 Trimble County Station Combustion Turbines

3.1.1 Technical Review Update

- Table 3.1-1 shows the net generation, EAF and EFOR for Trimble CT Units from 2004 through July 2009. A review of the station's availability and outage reports since January 2008 indicates that in general the Trimble County combustion turbines have performed consistent with historical operations.
- Major planned and forced outage events during 2008 and through July 2009 are discussed below:
  - A planned general gas turbine inspection of Unit 6 occurred during May 2008 that lasted 609 hours.
  - In April 2009, a forced outage impacted Unit 6's availability. The outage was caused by the gas turbine fuel nozzles and lasted 376 hours.
  - During March and April 2008, Unit 7 underwent a planned combustion inspection that lasted 790 hours.
  - During January and February 2009, Unit 9 underwent a planned general inspection that lasted 790 hours.
  - In 2008, Unit 10 performance was impacted by a number of forced and planned outages. In late February and March 2008 the unit was subjected to a planned combustion inspection outage that lasted 666 hours. In April 2008 the unit was forced offline (unplanned outage) to address gas turbine vibration.
- In 2008 Trimble County Combustion Turbine Station's total controllable expenses were over budget by approximately 21 percent ($720,000). The unplanned outage on Unit 10 resulted in an unbudgeted expense of $1.07 million in 2008, although approximately $310,000 was offset by reduced outage work scope on Unit 6.
- Except for Unit 10, the turbines' five year average EAF and EFOR have been comparable with industry expectations.
- Unit 10's five year average EAF is slightly below industry averages over the same time period. The five year average EFOR is significantly above the industry average over the same time period.
- Turbine inspections were conducted on Units 6, 7 and 9 during the last 18 months. A maintenance outage is planned for Unit 5 for the fourth quarter of 2009.

Table 3.1-1
Historical Performance Data for Trimble County Generating Station

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 5							
Net Generation (MWh)	21,655	9,696	11,781	92,511	73,993	27,940	41,927
Equivalent Availability Factor (%)	96.6	98.2	99	98.8	99.1	99.5	98.3
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	27.3	34.4	27.2	11.1	2.2	0.2	20.4
Industry Average EFOR (%)							*21.0*
Unit 6							
Net Generation (MWh)	22,823	22,419	23,800	83,953	69,784	16,317	44,556
Equivalent Availability Factor (%)	96.2	98.3	98.4	98.6	91.5	90.4	96.6
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	25	18.5	26.1	35.7	2.5	18.7	21.6
Industry Average EFOR (%)							*21.0*
Unit 7							
Net Generation (MWh)	13,524	44,210	50,944	112,701	59,477	23,991	56,171
Equivalent Availability Factor (%)	92.2	97.8	94.7	96.5	88.1	99.6	93.9
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	35.2	11.3	47.4	2.5	16	0	22.5
Industry Average EFOR (%)							*21.0*
Unit 8							
Net Generation (MWh)	5,784	77,153	76,814	149,775	63,039	18,516	74,513
Equivalent Availability Factor (%)	91.3	97.7	97.5	97.9	98.6	99.5	96.6
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	42.2	10.8	15.5	1.9	7.64	1.1	15.6
Industry Average EFOR (%)							*21.0*
Unit 9							
Net Generation (MWh)	9,370	46,514	59,506	148,371	58,192	15,242	64,391
Equivalent Availability Factor (%)	90	98.8	96.4	97.4	98.6	83.8	96.2
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	29.7	6.8	14.5	3.1	3.12	0	11.4
Industry Average EFOR (%)							*21.0*
Unit 10							
Net Generation (MWh)	1,387	90,645	71,377	130,929	51,431	14,420	69,154
Equivalent Availability Factor (%)	83.9	96.3	93.8	95.3	78	97.5	89.5
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	94.8	22.8	45.4	0.9	71.21	40	47.0
Industry Average EFOR (%)							*21.0*

Averages include data from 2004 through 2008

3.1.2 Environmental Review Update

- EON submitted a 2008 Annual Air Compliance Certification indicating that they are in compliance with their permit conditions with the exception of a few items noted below:
  - The current air construction and operating permit (Permit No. V-02-043, Revision 3) notes the CO emission limit for the CTs is 9 ppm, but the 2008 Annual Air Compliance Certification indicates that the CTs CO emissions limit is 9.5 ppm. Based on the 9.5 ppm CO emissions limit noted in the report, no excess emissions were reported for these units. However, no additional CO emissions information on individual CTs was available for review to determine if these units were exceeding their 9 ppm CO emissions limit.
  - The current air construction and operating permit (Permit No. V-02-043, Revision 3) notes that the NO_x annual emissions limit for the CTs is 9 ppm and 12 ppm on a hourly basis. CTs 5, 6, 9 and 10 on a few occasions exceeded their emission limit between July and December 2008.
  - The CT NO_x CEMs for all six units were unavailable for greater than approximately 15-20 percent of their operating time.
- The environmental review for the Trimble County units was conducted with that of the Trimble County coal units please refer to Section 2.1.2 for additional information.

3.2 E.W. Brown County Station Combustion Turbines

3.2.1 Technical Review Update

- Table 3.2-1 shows the net generation, EAF and EFOR for E.W. Brown CT Units from 2004 through July 2009. A review of the station's availability and outage reports since January 2009 indicates that in general the Trimble County combustion turbines have displayed improved performance when compared with historical operations.
- Major planned and forced outage events during 2008 and through July 2009 are discussed below:
  - In March 2008, maintenance forced outages impacted Unit 5 availability. The outages were caused by the gas turbine starting system and lasted 267 hours.

Table 3.2-1
Historical Performance Data for E.W. Brown Station Combustion Turbines

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 5							
Net Generation (MWh)	0	122,928	30,777	19,823	2,340	2,681	35,174
Equivalent Availability Factor (%)	99	99.3	91.4	95.7	95.88	99	96.3
Industry Average EAF (%)							*91.9*
Equivalent Forced Outage Rate (%)	87.3	5.1	53.3	43.4	11.2	27.1	40.1
Industry Average EFOR (%)							*43.7*
Unit 6							
Net Generation (MWh)	10,697	172,114	97,500	88,563	21,817	29,144	78,138
Equivalent Availability Factor (%)	79.7	68.3	90.1	79.4	95.06	86.8	82.5
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	65.2	59.1	14.3	21.2	48.9	43.4	41.7
Industry Average EFOR (%)							*21*
Unit 7							
Net Generation (MWh)	20,845	156,711	99,267	51,599	33,143	22,332	72,313
Equivalent Availability Factor (%)	94.7	62.6	95.3	0.8	82.9	98.4	67.3
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	61.8	50.6	12.5	62.4	13	6.8	40.1
Industry Average EFOR (%)							*21*
Unit 8							
Net Generation (MWh)	0	2,954	46,424	19,870	6,622	4,731	15,174
Equivalent Availability Factor (%)	83.1	34.9	88.4	62.1	95.3	98.6	72.8
Industry Average EAF (%)							*91.9*
Equivalent Forced Outage Rate (%)	34.5	98.8	58.4	1.1	55.1	21.2	49.6
Industry Average EFOR (%)							*43.7*
Unit 9							
Net Generation (MWh)	0	1,636	27,103	11,236	3,411	878	8,677
Equivalent Availability Factor (%)	99.9	35.7	82.2	55.7	94.5	98.4	73.6
Industry Average EAF (%)							*91.9*
Equivalent Forced Outage Rate (%)	13.6	99.2	36.7	1.9	49.2	61.5	40.1
Industry Average EFOR (%)							*43.7*
Unit 10							
Net Generation (MWh)	772	1,683	20,966	5,334	1,722	2,590	6,095
Equivalent Availability Factor (%)	99	35.7	74.8	55.7	96.69	98.8	72.4
Industry Average EAF (%)							*91.9*
Equivalent Forced Outage Rate (%)	22.7	99.3	86.9	31.4	0.8	42.3	48.2
Industry Average EFOR (%)							*43.7*
Unit 11							
Net Generation (MWh)	467	1,854	12,930	4,458	677	2,848	4,077
Equivalent Availability Factor (%)	99.1	35.7	64.3	50.5	96.55	99.2	69.2
Industry Average EAF (%)							*91.9*
Equivalent Forced Outage Rate (%)	28.7	99.2	93.1	3.3	79.7	39	60.8
Industry Average EFOR (%)							*43.7*
Averages include data from 2004 through 2008							

- In 2008, Unit 6 performance was impacted by three forced outages. In January, the unit was forced offline (unplanned outage) to address the gas turbine fuel system. In February, an unplanned outage was caused by the gas turbine control system hardware. In March, the unit was impacted by an unplanned outage caused by the gas turbine starting system. The total impact of the outages aggregated to 235 hours.
- In 2009, a planned gas turbine boroscope inspection of Unit 6 occurred during April – May 2009 that lasted 291 hours. In May 2009, a forced outage caused by malfunctioning compressors impacted the unit's availability by 305 hours.
- A planned gas turbine overhaul of Unit 7 occurred during October – December 2008 which lasted approximately 1,385 hours.
- In January 2008, Unit 8 was impacted by a forced outage caused by the gas turbine inlet air vanes. The outage lasted 120 hours. In May 2008 the unit was subjected to a forced outage to conduct a boroscope inspection. The outage lasted 200 hours.
- During April - May 2008, an unplanned boroscope inspection was performed on the unit which lasted approximately 400 hours.
- In April 2008, Unit 10 was subjected to maintenance outages that involved the gas turbine starting system and a boroscope inspection. The outages lasted approximately 230 hours.
- In 2008, Unit 11 was subjected to several small forced outage events that aggregate to 212 hours.

• A review of E.W. Brown Generating Station's total controllable expenses budget indicates that the 2008 expenses were under budget by 6 percent ($315,000). As of July 2009, the station is performing 25 percent ($484,000) under budget. The station is expected to perform favorably in 2009.

• In 2008 and through July 2009 most of the E.W. Brown units suffered outages due to the gas turbine starting system. According to EON, the starting reliability of the CTs in 2008 ranged between 85 and 90 percent.

• Turbine boroscope inspections were conducted on Units 8, 9, 10 & 11 during the last 18 months. A major gas turbine overhaul was conducted on Unit 7 in 2008.

- Average availabilities over the last five years indicate that most of the E.W. Brown units are below industry averages. High EFOR averages and the subsequent impact on EAF are mostly due to GT24 and GT11N2 fleet issues. Over the last 18 months however, the availabilities of the units have improved and are comparable to industry averages.

3.2.2 Environmental Review Update

- The environmental review for the E.W. Brown CT units was conducted with that of the E.W. Brown coal units. Please refer to Section 2.5.2 for additional information.

3.3 Paddy's Run County Station Combustion Turbines

3.3.1 Technical Review Update

- Table 3.3-1 shows the net generation, EAF and EFOR for Paddy's Run CT Units from 2004 through July 2009. A review of the stations' availability and outage reports since January 2008 indicates that in general the Paddy's Run combustion turbines have performed consistent with historical operations.
- Major planned and forced outage events during 2008 and through July 2009 are discussed below:
  - In 2008, Unit 12 was impacted by three unplanned outages. The outages were caused by instrument air compressors and closed cooling water pumps and lasted 978 hours.
  - In February 2009, Unit 12 experienced startup failure caused by the hydrogen system. In July 2009, the unit experienced a maintenance outage caused by external switchyard circuit breakers. The outage was followed by the unit being placed on reserve shutdown.
  - A planned gas turbine combustion liner inspection and maintenance of Unit 13 occurred during April – June 2008 and lasted approximately 1,775 hours.
  - During 2009, Unit 13 experienced several forced and maintenance outages. The most significant forced outage involved the unit control system in June, resulting in the unit being placed on reserve shutdown for 83 hours following the outage.

Table 3.3-1
Historical Performance Data for Paddy's Run Station
Combustion Turbines

	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 11							
Net Generation (MWh)	0	645	813	87	-95	-51	290
Equivalent Availability Factor (%)	99.9	100	95.3	N/A	99.9	99.4	98.8
Industry Average EAF (%)							*89.6*
Equivalent Forced Outage Rate (%)	100	-	80.2	94.2	0	94.4	68.6
Industry Average EFOR (%)							*65.8*
Unit 12							
Net Generation (MWh)	0	256	232	0	-159	-73	66
Equivalent Availability Factor (%)	99.3	95.8	64.2	81	88.9	96.7	85.8
Industry Average EAF (%)							*88*
Equivalent Forced Outage Rate (%)	100	93.5	99.4	99.5	99.9	100	98.5
Industry Average EFOR (%)							*56.6*
Unit 13							
Net Generation (MWh)	31,324	134,268	88,206	71,491	3,654	303	65,789
Equivalent Availability Factor (%)	92.3	98.2	86.3	92.5	78.6	98.3	89.6
Industry Average EAF (%)							*91.5*
Equivalent Forced Outage Rate (%)	49.8	14.9	78.6	60.6	37	96.6	48.2
Industry Average EFOR (%)							*21*

Averages include data from 2004 through 2008

- Units 11 and 12 did not account for any positive net generation between Jan 2008 – July 2009.
- O&M costs for the Cane Run Station/Zorn CTs are included with the Paddy's Run CTs and the Ohio Falls operating budget. A review of Paddy's Run Generating Station's controllable expenses budget indicates that the 2008 expenses were over budget by 196 percent ($498,000). The variance was due to additional labor involved with emergency repairs to Unit 13. As of July 2009, the station is performing on budget.
- The Paddy Run units' availabilities have been comparable with industry averages in 2008 through July 2009, with the exception of Unit 13 due to a planned combustion liner inspection in 2008.
- Unit 11 and 12 continue to exhibit low utilization. Discussions with plant staff in 2007 indicated that the 2008 to 2012 budget did not include major overhaul maintenance for these units due to low forecasted utilization, declining reliability and an increased cost to maintain.

3.3.2 Environmental Review Update

- The Paddy's Run Station's air permit is a Part 70 Title V operating permit (Permit No. 130-97-TV) that expired on December 17, 2004. According to the 2007 Annual Title V Compliance Certification, EON submitted a Title V renewal application on June 11, 2004, but a proposed or final permit has not been issued by the Jefferson County Air Quality Agency. In the interim, EON is allowed to continue to operate the station in accordance with the terms and conditions of the expired permit under a permit shield until a new permit is issued.
- A review of compliance data available on the EPA ECHO Web site indicated that the Paddy's Run facility is in compliance with the Clean Air Act Provisions.
- The 2008 Title V compliance certification report indicates that the Paddy's Run facility is in continuous compliance with all the requirements of the Title V Permit. The compliance report points out that Paddy's Run Unit 1 is subject to the Federal NO_x Budget Trading Program. A NO_x Budget Application and Certificate of Representation was submitted as applicable, however, a monitoring plan and annual NO_x Budget certifications were not submitted as required by the program. Per EPA guidance, EON submitted a petition to EPA on March 16, 2008 and received a response from the EPA on January 6, 2009. Details of the response are not available in the documents provided.
- No compliance issues were identified in the two wastewater discharge reports for the 2008 Tier II report. The EPA ECHO report for Paddy's Run did not identify any Clean Water Act or RCRA compliance issues.

3.4 Cane Run Combustion Turbines

3.4.1 Technical Review Update

- Table 3.4-1 shows the net generation, EAF and EFOR for Cane Run CT Units from 2004 through July 2009. A review of the stations' availability and outage reports over the last 18 months indicates that in general the Cane Run combustion turbines have performed consistent with historical operations.

Table 3.4-1 Historical Performance Data for Cane Run Station Combustion Turbines							
	2004	2005	2006	2007	2008	2009 July YTD	Average
Unit 11							
Net Generation (MWh)	33	143	1,179	312	4	210	334
Equivalent Availability Factor (%)	96.5	64.3	83.8	76.7	97.8	97.4	83.8
Industry Average EAF (%)							*89.6*
Equivalent Forced Outage Rate (%)	98.6	99.6	72.3	56.5	99.4	82.4	85.3
Industry Average EFOR (%)							*65.8*
Zorn 1							
Net Generation (MWh)	0	0	0	0	-134	-51	-27
Equivalent Availability Factor (%)	93.2	85.3	92.2	89.1	99.2	35.9	91.8
Industry Average EAF (%)							*89.6*
Equivalent Forced Outage Rate (%)	52.9	74.2	58.8	24	0	99.6	42.0
Industry Average EFOR (%)							*65.8*
Averages include data from 2004 through 2008							

- Major planned and forced outage events during 2008 and through July 2009 are discussed below:
  - In 2008, Unit 11 performance was impacted by a number of forced outages. The forced outages were individually caused by instrument air piping, lightening strike, gas turbine battery & charger system, gas turbine fuel oil pump and AC instrument power. The unit's availability was affected by approximately 192 hours. It should be noted that the unit operated infrequently in 2008.
  - During 2009, Unit 11 was affected by forced outages caused by a malfunctioning process computer. The outages impacted the unit performance by 77 hours of lost generation.
  - In January 2009, the Zorn Unit 1 availability was impacted by a significant forced outage caused by DC power problems. As a result of the outage, the unit was forced offline for approximately 3,259 hours, which had a major impact on the availability of the unit.

- Cane Run and Zorn units are maintained and operated by the Cane Run coal station personnel. O&M costs for the Cane Run Station/Zorn CTs are included with the Paddy's Run CTs and the Ohio Falls operating budget. Please refer to Section 3.3 for information regarding the budget performance of the units.
- Discussions with plant staff in 2008 indicated that the 2008 to 2012 budget did not include costs for major overhaul maintenance for Cane Run Unit 11 or Zorn Unit 1 due to low utilization, declining reliability and maintenance costs.

3.4.2 Environmental Review Update

- The environmental review for the Cane Run units was conducted with that of the Cane Run coal units. Please refer to Section 2.3.2 for additional information.

4.0 Hydroelectric Generating Plants

4.1 Ohio Falls Hydro Electric Generating Station

4.1.1 Technical Review Update

- Table 4.1-1 shows the 2004 through July 2009 net generation for Ohio Falls Hydro station. As the station is a run-of-river generating station the water flow is controlled by the US Army Corps of Engineers (USACE). Over the last 5 years the capacity factor has ranged between 20 percent in 2007 and 30 percent in 2004.

Table 4.1-1
Net Generation for Ohio Falls Hydro Electric Generating Station

	2004	2005	2006	2007	2008	2009 July YTD	Average
Net Generation (MWh)	214,785	194,203	239,852	140,996	161,996	109,025	176,810

- In 2008 Ohio Falls' controllable expenses were under budget by 44 percent ($1.24 million). As of July 2009 they are 20 percent under budget ($0.22 million). The budget performance in 2008 and 2009 is related to work scope reduction in the station redevelopment project and the cancellation of capital projects in 2009.
- The rehabilitation project to upgrade and rehabilitate each of the eight turbine/generator units has been delayed due to cost escalation concerns. Plant staff indicated that the schedule will be revised during the next planning period (2010-2012).

4.2 Dix Dam Hydro Electric Generating Station

4.2.1 Technical Review Update

- Table 4.2-1 shows the 2004 through July 2009 net generation for Dix Dam Hydro station. The Dix Dam station is dispatched according to the water level of Herrington Lake, for flood control by the USACE. Over the last five years the capacity factor of the units has ranged from 16 percent in 2007 to 45 percent in 2004.

Table 4.2-1
Historical Performance Data for Dix Dam Hydroelectric Generating Station

	2004	2005	2006	2007	2008	2009 July YTD	Average
Net Generation (MWh)	94,610	36,579	47,026	35,068	50,505	40,653	51,493

- In 2008 the Dix Dam controllable expenses were under budget by 32 percent ($216,000) and are currently over budget by 88 percent as of July 2009 ($192,000) due to the failure of Dix Dam Unit 1 transformer. The current controllable expense end of year 2009 forecast is $874,000 ($285,000 over budget).
- The project to overhaul each of the three turbines from 8 MW to 9.7 MW began in 2009 with the overhaul of Unit 3. The overhaul of Unit 1 and Unit 2 has been delayed due to cost escalation concerns until the next planning period (2010-2012).

5.0 Trimble County Unit 2 Development

5.1.1 Technical Review Update

Black & Veatch reviewed the following documentation related to the construction of Trimble County Generating Unit No. 2;

- July 2009 Bechtel Monthly Progress Report
- EPC Contract Amendment – Labor Settlement (from March 2009)
- July 2009 HDR Independent Engineer's Monthly Progress Report

Schedule

- The progress report indicates that the target commercial operation date has been revised to June 14, 2010. This is one day prior to the guaranteed commercial operation date. Black & Veatch notes that there is little margin between the target and guaranteed commercial operation date.
- The actual project percent complete was 69.5 percent as of July 2009, compared to the planned percent complete of 68.4 percent based on the June 2009 revised project forecast.
- Over the next eleven months the EPC contractor must achieve a monthly percent completion of approximately 2.5 to 3 percent. Black & Veatch finds that this rate is achievable, however notes that as the project progresses the interdependency between construction tasks and equipment tie-ins will become more critical. As previously stated in our 2008 report a rate of 3 percent is reasonable and the EPC contract appears to have sufficient provisions to protect EON from schedule delay.

Change Orders and Force Majeure Events

- The total approved change orders of the project is approximately $20.5 million as of July 2009. This total approved change order amount is equal to approximately 2 percent of the original EPC contract price. The approved change order amount to date includes a $13.3 million labor settlement, which is further described below:
  - A labor settlement agreement between Bechtel Power Corporation and Trimble County Unit 2 was executed on March 19, 2009. The settlement provides for changes to Section 8.15 Labor/Per Diem Adjustment of the EPC Agreement, which has been in dispute since 2007. The changes include improved remuneration benefits for the Bechtel construction team. As a result of this labor

settlement, four change orders were approved totaling over $13.3 million. The most significant of these was Change Order Number 61 for labor expenses between July and December 2008, for over $8.3 million. The change orders were not associated with any change in the project schedule.

- Multiple force majeure change orders have been approved totaling in excess of $485,000. In addition there are three force majeure events which remain open of which two are related to abnormal weather events from February 2009.

Budget

- Year to date July 2009, the Trimble County Unit 2 capital expenditure is below budget by 4.3 percent (or approximately $3.5 million), due to project delays in the first quarter. The project is expected to make up these expenses in the second half of the year.
- Capital expenditure at Trimble County Unit 2 was $26 million (or 8.8 percent) below budget in 2008.

5.1.2 Environmental Review Update

As of September 2009, TC2 has not been issued a final PSD/Title V permit. The initial PSD application for TC2 was filed in December 2004. Since Kentucky has a dual PSD/Title V permit program, KDAQ included the PSD permit for TC2 in Trimble County facility's Title V permit. On April 21, 2009, KDAQ issued a proposed permit (Revision 4), which was objected to by the EPA in a June 5, 2009 letter. EPA wanted EON to perform a Section 112(g) Case-by-Case Maximum Achievable Control Technology (MACT) analysis for all Hazardous Air Pollutants (HAPs) being emitted from TC2. The EPA also objected to wording related to startup and shutdown. In response to the EPA objections, EON submitted a letter dated July 10, 2009 to KDAQ which concluded that the TC2 is not a major source of HAPs and therefore is not subject to any obligations under CAA Section 112(g) to perform a Case-by-Case MACT determination. A final outcome of this issue is yet to be determined.

On August 12, 2009, the EPA issued an order responding to issues raised in the April 28, 2008 and March 2, 2006 petitions, denying in part and granting in part requests for objections to the PSD permit. While most of the petitions were denied by EPA, the following were granted:

- Petitioners' claims regarding Best Available Control Technology (BACT) for auxiliary boiler. The EPA is requiring a revised BACT analysis on the auxiliary boiler. The result of this analysis can potentially lead to modifying the pollutant emission limits and/or addition of an oxidation catalyst.

- Use of PM_{10} as surrogate for $PM_{2.5}$. The EPA concurred with the petitioners concerns on whether or not PM_{10} could be used as a suitable surrogate for $PM_{2.5}$, and is directing the KDAQ to address the $PM_{2.5}$ issue. The EPA suggests possible approaches to demonstrating compliance with the PSD requirements for $PM_{2.5}$. It remains to be seen how KDAQ intends to address this issue. TC2 has the latest air pollution control technologies; therefore, it is unlikely that additional controls will be needed. However, pollutant emission limits could potentially be modified.

6.0 Regulatory and Compliance Summary

The environmental permit status and regulatory compliance updates from July 2008 Through August 2009 were provided for each EON facility in Sections 2, 3, 4 and 5. However, the scope of this addendum does not include an update to the evaluations of future environmental regulations and compliance previously discussed in the October 2008 Report.

7.0 Operating Programs and Procedures

According to EON, there has not been any significant change or revision to the O&M plans and processes for the EON generating assets.

8.0 Contracts and Agreements

8.1 Contracts and Agreements

Black & Veatch review new agreements and amendments to existing agreements that were executed over the past 12 months. EON provided 24 agreements that were new and/or amended since our previous report.

8.1.1 Coal Supply and Transportation Contracts

- The majority of contracts provided for review were for coal supply and transportation. There were 15 agreements for supply, of which 10 were amendments in price and or quantity and 5 agreements were for transportation. There were 6 new or updated coal transportation agreements.
- The coal supply agreements were established with existing suppliers and contain similar terms and conditions relative to previous agreements. There have been some changes to the quality of coal received (reduced sulfur). The one exception was a new contract with coal supplier Rhino Energy. Terms and conditions within the amended and new coal supply agreements are considered to be reasonable.
- EON has entered into a new coal transportation agreement with Norfolk Southern Railway for delivery to the Cane Run facility through 2011.
- EON has entered into a new agreement with Mill Creek Harbor Services for mooring, maneuvering, towing, switching, fleeting, and surveillance service at EON's Mill Creek barge. The contract was effective in October 2008 and has a term of 20 years. The general terms and conditions appear to be reasonable.
- The transportation rates included in the Crouse Corporation barge agreement (major agreement covering transportation to the majority of the coal facilities) was updated for 2009 based on the escalation terms in the existing contract.

8.1.2 EON Fuel Supply and Transportation Strategy and Policy

- It appears that EON has continued to ensure that the quantity of coal supplied under all contracts is maintained on an annual basis. EON has indicated that there has been no change in their approach to procure coal over the past 12 months and they will continue to re-negotiation and re-contract as needed. EON has continued to maintain diversity in suppliers.

- EON indicated that they have not made significant updates to their fuel procurement polices and procedures
- Based on a review of the Corporation Fuels and By Products report from June 2009, the following issues with respect to fuel supply have been identified.
  - Pricing has been adversely impacted by changes in government regulation (MINER Act law)
  - Overall the portfolio has experienced lower generation than budget (in particular the closing of Tyrone Unit 3.)
  - EON commenced 2009 with an extra 3 percent coal inventory of LG&E and year to date receipts at 212,000 tons over budget.
  - EON's KU started 2009 22 percent below target inventory levels and year to date receipts are 168,000 tons under budget, however this is offset by reduced consumption.
  - Overall fuel expenditure year to date has been close to budget.

9.0 Projected Performance and Operating Costs

9.1 Projected Performance

- The 2009 through 2012 projected performance for all EON generating units shown in Appendix A.1 of the Report is still considered reasonable based on Black & Veatch review of the actual performance for the units for 2008 and year to date July 2009. In general, EON expects that the units will perform at levels that are comparable to generating units of similar type and size in the industry.

9.2 Projected O&M Costs

- Based on Black & Veatch review of the latest EON Generation Financial Reports, the actual 2008 total non-fuel O&M cost for the EON fleet was approximately 3 percent (or $7.65 millions) lower than the 2008 budget. The actual year to date June 2009 non-fuel O&M cost was approximately 1 percent (or $1.44 millions) higher than the year to date June 2009 budget. The actual versus budget variances in 2008 and year-to-date July 2009 are within the range that is expected for a fleet of this type and size.

9.3 Projected Capital Expenditures

- The actual 2008 total capital expenses were 15 percent (or $114.1 millions) lower than the 2008 capital budget. The favorable variance in 2008 were due to the one year delay on the planned Brown FGD ($55 millions) project, the budgeted milestone payments of $26 millions for TC2 project that did not occur because the EPC contractor did not achieve certain milestones in 2008, cancellation of Ghent Dewatering project ($14 millions), and other smaller planned capital projects that was cancelled or delayed in 2008. The actual year to date June 2009 capital expenses were approximately 20 percent (or $52.5 millions) lower than the year to date June 2009 budget. However, the total capital costs for 2009 at year end is forecast to be 1 percent (or $5.2 millions) higher than the 2009 EON budget. The variances in the actual, forecast, and budget capital expenses identified above are considered within the range that is expected for a fleet of this type and size.

- A review of the planned capital projects listed in the latest EON capital expenditure plan for 2010 through 2012 indicated that the projects are justified based on review of the latest available documents and industry trend.

Attachment 1
Key Environmental Documents Reviewed

General Documents (multiple facilities)

- ATC Associates Inc, Visual Site Assessment Report, Low Hazard Dams, Various Kentucky Power Plants, March 19, 2009
- ATC Associates Inc, Visual Site Assessment Report, Eight Ash Pond Dams, February 20, 2009
- EON, Response to Request for Information under Section 104(e) of CERCLA, sent to US EPA, March 25, 2009.
- EON, Comprehensive Strategy for Management of Coal Combustion Byproducts, Kentucky Utilities and Louisville Gas and Electric, June 2009

Trimble

- September 10, 2008 Petition Order issued by the USEPA on Revision 2 of the PSD/Title V Permit.
- August 12, 2009 Petition Order issued by the USEPA on Revision 3 of the PSD/Title V Permit.
- June 5, 2009 Objection Letter from USEPA on Revision 3 of the PSD/Title V Permit.
- July 10, 2009 LG&E's Case-by-Case MACT Applicability Analysis.
- Trimble County Unit 2 proposed revision to PSD/Title Permit, Permit No. V-08-001, dated April 21, 2009
- Proposed PSD/Title V Permit Statement of Basis, Comments and Application Summary, dated April 21, 2009.
- 2008 Tier II Report
- 2008 TRI Report
- Discharge Monitoring Reports, July 2008-March 2009
- Groundwater Monitoring Reports, 2008 - June 2009
- 2008 Hazardous Waste Annual Report Form 1
- KPDES Discharge Permit KY0041971, issued August 4, 2009 by KDEP
- O'Brien & Gere, Trimble County BAP Assessment, draft for US EPA, July 3, 2009

Black & Veatch also obtained a recent summary of the facility's compliance status from the US Environmental Protection Agency (EPA) "Enforcement and Compliance History Online" (ECHO) database on August 18, 2009.

Mill Creek

- 2008 Emissions Inventory Spreadsheet.
- 2008 TRI Report
- ECMPS Monitoring Plan Printout, dated August 10, 2009.
- 2008 Tier II Report
- Discharge Monitoring Reports, July 2008-March 2009
- Groundwater Monitoring Reports, June 2008 - June 2009
- 2008 Hazardous Waste Annual Report Form 1

Black & Veatch also obtained a recent summary of the facility's compliance status from the EPA ECHO database on August 18, 2009.

Cane Run

- 2008 Air Emissions Inventory SAM Forms dated April 15, 2009.
- ECMPS Monitoring Plan Printout, dated Aug 10, 2009.
- TRI Report for 2008.
- 2008 Tier II Report
- Discharge Monitoring Reports, July 2008-March 2009
- Groundwater Monitoring Reports, 2008 - June 2009
- 2008 Hazardous Waste Annual Report Form 1
- Notice of Violation from KDEP, February 6, 2009

Black & Veatch also obtained a summary of the facility's compliance status from the EPA ECHO database on August 18, 2009.

Ghent

- 2008 Annual Air Compliance Certification dated January 26, 2009.
- 2008 Emissions Inventory Spreadsheet.
- August 6, 2008 KDAQ Letter of Warning related to emissions of airborne particulates beyond the premises of origin and crossing the facility property line.

- August 15, 2008 KU response and Corrective Action Plan to address KDAQ's August 6, 2008 Letter of KDAQ Warning.
- March 19, 2009 Notice of Violation from the USEPA to KU notifying KU about the PSD violations for sulfuric acid mist (SAM) emissions.
- TRI Report for 2008.
- ECMPS Monitoring Plan Printout, dated April 2, 2009.
- 2008 Tier II Report
- Discharge Monitoring Reports, July 2008-March 2009
- 2008 Hazardous Waste Annual Report Form 1

Black & Veatch also obtained a recent summary of the facility's compliance status from the EPA ECHO database on August 18, 2009.

EW Brown (Coal)

- October 20, 2008 Rescission of Notice of Violation (ENV20050001) for opacity exceedances
- 2008 Annual Air Compliance Certification dated January 26, 2009.
- March 17, 2009 Final Consent Decree for PSD and NSPS violations.
- June 26, 2009 Application of Kentucky Utilities (KU) Company for Certificates of Public Convenience and Necessity (CPCN) and Approval of its 2009 Compliance Plan for Recovery by Environmental Surcharge.
- July 6, 2009 letter from the Kentucky Public Services Commission confirming filing of the CPCN Application which has met the minimum filing requirements.
- July 9, 2009 modification to the facility's PSD/Title V Permit V-03-023 for the installation of SCR on Unit 3.
- 2008 TRI Reportable Releases.
- Aug 10, 2009 ECMPS Monitoring Plan Printout
- 2008 Tier II Report
- Discharge Monitoring Reports, July 2008-March 2009
- Groundwater Monitoring Reports, 2008 - June 2009
- 2008 Hazardous Waste Annual Report Form 1

Black & Veatch also obtained a recent summary of the facility's compliance status from the US Environmental Protection Agency (EPA) "Enforcement and Compliance History Online" (ECHO) database on August 18, 2009 and EPA's Civil Enforcement website database on August 24, 2009.

Green River

- 2008 Emissions Inventory Spreadsheet.
- 2008 Annual Air Compliance Certification dated January 26, 2009.
- TRI Report for 2008.
- ECMPS Monitoring Plan Printout, Aug 10, 2009.
- 2008 Tier II Report
- Discharge Monitoring Reports, July 2008-March 2009

Black & Veatch also obtained a recent summary of the facility's compliance status from the US Environmental Protection Agency (EPA) "Enforcement and Compliance History Online" (ECHO) database on August 18, 2009.

Tyrone

- 2008 Emissions Inventory Spreadsheet.
- 2008 Annual Air Compliance Certification dated January 26, 2009.
- ECMPS Monitoring Plan Printout, dated Aug 10, 2009.
- November 26, 2008 Notice of Violation letter from KDEP to KU.
- July 30, 2009 Agreed Order (not yet signed by all parties) from the KDEP to KU for resolving PM compliance issues.
- TRI Report for 2008.
- 2008 Tier II Report
- Discharge Monitoring Reports, July 2008-March 2009

Black & Veatch also obtained a summary of the facility's compliance status from the EPA ECHO database on August 18, 2009.