Jasper Municipal Electric Utilities

Plant Condition Assessment Study

Final Report

B&V Project: 166183

January 2010

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Acronyms

acfm	Actual Cubic Feet per Minute
B&V	Black & Veatch Corporation
BACT	Best Available Control Technology
BAE	Baseline Actual Emissions
bhp	Boiler Horsepower
BOP	Balance of Plant
Btu	British Thermal Units
CAA	Clean Air Act
CFR	Code of Federal Regulations
CHP	Combined Heat and Power
the City	City of Jasper
CO	Carbon Monoxide
DCF	Discounted Cash Flow
DCS	Distributed Control System
DOE	Department of Energy
EAF	Equivalent Availability Factor
EFOR	Equivalent Forced Outage Rate
EIA	Energy Information Administration
EMP	Energy Market Perspective
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
EUSGU	Electric Utility Steam Generation Units
FD	Forced Draft Fan
FERC	Federal Energy Regulatory Commission
GE	General Electric
gpm	Gallons per Minute
GW	Gigawatt (Billion Watts)
GWh	Gigawatt-hours
HCl	Hydrogen Chloride
hp	Horsepower

Hg	Mercury
HP	High-Pressure
ID	Induced Draft
IDEM	Indiana Department of Environmental Management
IMPA	Indiana Municipal Power Agency
JMEU	Jasper Municipal Electric Utilities
K_2O	Potassium Oxide
kg/h	Kilograms per Hour
kV	Kilovolt (1000 volts)
kVA	Kilovolt-ampere (1000 volt-ampere)
kW	Kilowatt (1000 watts)
kWh	Kilowatt-hour
LAER	Lowest Achievable Emission Rate
LNB	Low NO_X Burner
LP	Low-Pressure
MACT	Maximum Achievable Control Technology
MCC	Motor Control Center
MHC	Mechanical Hydraulic Control
MISO	Midwest Independent Transmission System Operator
mmBtu	Million British Thermal Units
MSW	Municipal Solid Waste
MVA	Megavolt-Ampere
MW	Megawatt
MWh	Megawatt-hour
NA_2O	Sodium Oxide
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Agency
NNSR	Nonattainment New Source Review
NO_x	Nitrogen Oxide
NPV	Net Present Value
NSPS	New Source Performance Standards

NSR	New Source Review
O&M	Operations and Maintenance
PAE	Projected Actual Emissions
PCB	Polychlorinated Biphenyls
PLC	Programmable Logic Controller
PM	Particulate Matter
$PM_{2.5}$	Particulate Matter Less Than or Equal to 2.5 Microns
PM_{10}	Particulate Matter Less Than or Equal to 10 Microns
PSD	Prevention of Significant Deterioration
psig	Pounds per Square Inch Gauge
PTE	Potential to Emit
quads	Quadrillion Btu
RPS	Renewable Portfolio Standards
SER	Significant Emission Rate
SO_2	Sulfur Dioxide
TOC	Trended Original Cost
TOCLD	Trended Original Cost Less Depreciation
tph	Tons per Hour
tpy	Tons per Year
USEPA	United States Environmental Protection Agency
V	Volt
VOC	Volatile Organic Compound

1.0 Executive Summary

1.1 Background

Black & Veatch Corporation (B&V) was retained by Jasper Municipal Electric Utilities (JMEU) to conduct an assessment of the existing JMEU plant to determine its existing condition, identify required upgrades to extend its life by another 20 years, provide a high level analysis of biomass co-firing and combined heat and power opportunities, and to determine the market value of the plant should the City of Jasper (the City) decide to sell the facility.

The activities that were performed in this project include the following items:

- A site visit including interviews with key plant management personnel and a walk-down inspection of the site to perform a physical assessment and determine the condition of the facility.
- System configuration review of the major equipment to identify modifications that have been performed and determine redundancy.
- Review of historical plant performance, operating and maintenance data, operating plans and budgets, and operations and maintenance (O&M) practices.
- A detailed component analysis including the age, technology, operation, capital expenditures, and maintenance history of the major equipment.
- A detailed boiler assessment.
- Environmental assessment.
- Identification of repairs and/or upgrades required at existing JMEU plant.
- Investigation of combined heat and power opportunities.
- Investigation of biomass co-firing opportunities and biomass material handling.
- Development of a base case for the existing JMEU plant.
- Valuation of existing JMEU plant assets.

1.2 Plant Description

The JMEU plant is located on East 15th Street, within the city limits of Jasper, Indiana. The facility was put into service in 1968 and consists of a Riley coal stoker boiler and a General Electric non-reheat steam turbine with an air-cooled generator. The boiler is rated for 140,000 lb/h steam at 625 psig (pounds per square inch gauge) and 825° F. Natural gas fuel is used as the fuel source during unit startup. The steam turbine has a rated pressure of 600 psig and 825° F and has an output of 14,500 kW (kilowatts). The generator produces 13,200 volts with a capacity of 14,490 kW. Generator output power enters the distribution system at one of several overhead distribution lines. Minimum stable load for the unit is approximately 5 MW (megawatts).

Cycle heat is rejected to a surface condenser. Cooling water for heat rejection is accomplished using a wet, mechanical draft cooling tower. Makeup water to the plant is supplied by the City. Cycle makeup water is supplied by a demineralizer water treatment system. All plant water blowdown goes to the city sewer.

The facility was designed as a baseload unit with periodic shut downs for maintenance. Because of the low wholesale market price of electricity and high costs of fuel, it is not economically feasible to continuously operate the plant. Therefore, since 2008, the plant has only operated periodically and receives monthly payments for being available to provide emergency capacity.

The primary fuel for the plant is bituminous coal, which is purchased from the Corning Mine in Cannelburg, Indiana, and delivered to the facility by a local trucking company. Coal handling equipment is in place to move the coal from the storage pile to the boiler for combustion. The bottom ash and fly ash systems collect and transport the ash to a storage bin onsite, which is then sold and hauled away to a concrete manufacturing plant. The boiler is fitted with a gas burner. Natural gas fuel is used only during startup operations.

1.3 Summary of Findings

The following subsections provide a summary of findings identified by B&V during the JMEU power plant condition assessment. These findings are discussed in greater detail throughout this report.

1.3.1 Condition Assessment

The plant condition assessment was carried out by a B&V team of engineers during the week of November 16, 2009, with the following findings:

- In general, the plant was found in good condition for its 40+ years of operation and records indicated that plant equipment was maintained properly over its operational history.
- No significant items were found that required immediate attention for continued plant operation.
- Most of the items found requiring repair and/or upgrade were either due to age or operation efficiency improvement.
- In conclusion, it is estimated that the plant remaining life without any major upgrades is approximately 5 years if normal maintenance is performed.

1.3.2 Life Extension Upgrades

If the City considers operating the plant for an extended period of time, it is recommended that the items listed in Table 1-1 be implemented.

The recommended schedule for the implementation of the items listed in Table 1-1 is such that any items that improve plant operation efficiency be done as soon as funds are available and the rest of the items be implemented as dictated by their remaining life expectancy and/or operation improvement.

1.3.3 Environmental Assessment

The JMEU plant may have to consider limiting its facility-wide emissions for regulated PSD (Prevention of Significant Deterioration) and NNSR (Nonattainment New Source Review) applicable pollutants to avoid PSD/NNSR applicability if plant life extension upgrades are implemented. If limiting the emissions is not economically feasible, then JMEU will have to subject the proposed project to major source NNSR/PSD review. The JMEU plant will be subject to the boiler MACT (maximum achievable control technology) requirements, regardless of any upgrades, after the revised rule is finalized (most probably in 2010) and will be required to demonstrate initial compliance within 3 years of the effective date of the final boiler MACT rule. If the plant continues to operate as-is without any upgrades, boiler MACT requirements will still be applicable and will need to be complied with.

The air permitting issues discussed above are manageable hurdles in the air permitting process if they are addressed early in the project development phase.

1.3.4 Performance

The plant was originally operated as a baseload facility until 1993, at which time it began operating in a cycling mode to reduce the electrical system daytime peak demand loads during the weekdays. During this time, load was increased during peak hours to 13 to 14 MW and then reduced to 7 MW during off-peak hours. At the end of 2008, the market price for coal-generated electric power decreased and coal prices increased, resulting in a discontinuance of operations. Currently, the plant only operates periodically as a facility providing emergency capacity to Indiana Municipal Power Agency (IMPA). As of October 2009, the JMEU facility had not been operated since July and had only operated on three separate occasions producing a total of 6,922 MWh (megawatt-hour) for the year.

Table 1-1
Life Extension Projects and Budget Cost

Item	Qty.	Unit	Description	Order of Magnitude Cost Estimate
1	1	LS	13.2 kV Switchgear Bus	$1,185,000
2	1	LS	House Service Substation Switchgear	$863,000
3	1	LS	Motor Control Centers	$283,000
4	1	LS	Uninterruptible Power Supply	$45,000
5	1	LS	Black Start Standby Diesel Generator	$578,000
6	1	LS	MARK Vie Total Plant Control System	$585,000
7	1	LS	Balance-of-Plant Controls Upgraded and Integrated into Steam Turbine Generator Control Upgrade	$500,000
8	1	LS	Detroit Stoker Grate, Seals, and Link Repairs	$30,000
9	1	LS	Replace Eight Chill Tubes Each Side of Grate	$25,000
10	1	LS	Replace Economizer U Bends and Cold End Tubes Rows 12, 13, 14, and 15	$450,000
11	1	LS	Boiler Economizer (4) Soot Blowers	$100,000
12	1	LS	Boiler Generating Bank (4) Electric Rotary Soot Blowers	$135,000
13	1	LS	Boiler Generator Bank Replacement	$350,000
14	1	LS	Super Heater Tube Alignment and Bracket Repair, Some Tube Replacement to Reduce Blockage and Velocity Issues	$50,000
15	1	LS	Boiler Water Side Acid Cleaning and Flashing	$100,000
16	1	LS	Steam Turbine Packing Refurbishment, Spill Strip Upgrade	$153,000
17	1	LS	Cooling Tower Rebuild	$225,000
18	1	LS	Boiler Feed Pump Motor	$45,000
19	1	LS	Traveling Tripper Hydraulic Repair	$13,500
20	1	LS	Condenser Eddy Current - Tube Replacement	$22,500
21	1	LS	Feedwater Heater/Deaerator Eddy Current Testing	$9,000
22	1	LS	Fire Protection System (Detection and Sprinklers in accordance with National Fire Protection Association [NFPA])	$40,500
23	1	LS	Dust Collection System (Ventilation Coal Areas and Cleaning)	$103,500
24	1	LS	Condenser Eddy Current - Tube Replacement	$22,500
25	1	LS	Generator Step-up Transformer and Transmission	$2,786,000
27			**Construction Direct Subtotal**	**$8,699,500**
28		10.0%	Contingency	$869,950
			Subtotal, Direct Construction	**$9,569,450**
Indirect Costs				
		2.0%	Testing and Commissioning	$191,389
		3.0%	General Conditions, Fee, Insurance, Mobilization	$287,084
		8.5%	Engineering and Design	$813,403
			Subtotal, Indirect Costs	**$1,291,876**
			Grand Total	**$10,861,326**

Based on the original plant guaranteed performance, the rated gross output of the plant was 14.5 MW and the gross heat rate was 10,495 Btu/kWh at full load. The gross plant output and estimated gross heat rate for 2005 through 2009 are listed in Table 1-2. The heat rate is based on the gross plant generation, coal usage, and coal heating values provided by the plant.

Table 1-2
Historical Output and Heat Rate

	Gross Plant Output (kWh)	**Estimated Gross Plant Heat Rate (Btu/kWh)[1]**
2005	24,276,000	14,816[2]
2006	56,767,200	14,510[2]
2007	56,246,400	14,677
2008	60,883,200	15,976
2009	6,921,600	15,237

[1]Estimate based on monthly coal consumption and heating values provided by JMEU.
[2]Coal heating values were not available for these years. Used 11,500 Btu/lb as a default value.

The gross heat rate data shown in Table 1-2 is considerably higher (worse) than the rated design heat rate. There are multiple factors that can contribute to the degraded heat rate. The most significant reason contributing to the higher heat rate of the JMEU unit is due to the fact that the plant does not operate continuously at full load. Because of this, the efficiency of the boiler and the turbine are lower than expected. There appeared to be a substantial increase in the plant heat rate from 2007 to 2008. Without additional operating data and information about the plant, B&V cannot determine the cause of the noteworthy increase. However, any of the items identified in the report for upgrade to improve efficiency will result in better heat rate, resulting in lower production cost per kWh.

1.3.5 Operations and Maintenance

The JMEU facility is staffed to provide O&M support for 24 hours per day and 7 days per week with 14 full-time employees. During any period when less than the full complement of equipment operators is required or when the plant is not operating, the operations personnel will supplement maintenance needs by performing routine maintenance and any additional maintenance activities that the specific operator is qualified to perform.

Historical O&M costs for the facility were provided by JMEU and are shown in Table 1-3.

Table 1-3
JMEU Historical O&M Costs

	Nonfuel O&M Cost ($)	Fuel Cost ($)	Total O&M Cost ($)	Total kWh Produced	Cost per kWh ($/kWh)
2007	818,038	2,018,689	2,836,727	50,008,000	0.0567
2008	679,219	2,479,228	3,158,446	55,107,000	0.0573
2009	382,536	272,992	655,528	5,794,000	0.113

Table 1-3 shows that the cost per kWh in 2009 is almost double from the previous years. Reductions in O&M by the City are recommended if plant operation is going to remain as it was in 2009.

1.3.6 Biomass Co-firing Opportunity

The opportunity of co-firing biomass in the existing coal spreader stoker boiler at the JMEU plant was analyzed with the following findings:

- The order of magnitude to implement a coal firing pneumatic system is approximately $1.5 million.
- The cofiring was based on the identified wood waste biomass fuel available at the JMEU plant provided by Bingham McHale (refer to Appendix B), at a cost of $20/t to replace 20 percent of the coal heat input.
- The cost savings strictly from fuel cost assuming coal of 11,200 Btu/lb and a delivered price of $70/t and wood biomass of 7,500 Btu/lb and a delivered price of $20/t, the net fuel savings per year is as follows:

40,000 ton/year x 20% = 8,000 ton/year of coal to be replaced with wood biomass provides

$$\left(8{,}000\ \mathrm{t} \times \$70/\mathrm{t} - \frac{11{,}200\ \mathrm{Btu/lb}}{7{,}500\ \mathrm{Btu/lb}} \times 8{,}000\ \mathrm{t} \times \$20/\mathrm{t}\right) = \$321{,}000 \text{ savings}$$

The fuel cost savings per year plus any other incentive applicable to the cost and use of biomass identified by Bingham McHale should make co-firing an attractive opportunity that should be analyzed in greater detail in the next phase of this project.

1.3.7 Full Biomass Conversion

A general overview of biomass energy policy, a discussion of biomass fuel considerations, and an order of magnitude cost for a full conversion to biomass for the JMEU plant is presented in detail in Section 9.0.

If a 100 percent conversion to biomass is considered for the JMEU plant, it is recommended that this subject be studied in greater detail to make sure the biomass material, its composition, and long-term availability are well defined.

The assumptions for a full biomass conversion costing are based on the use of green wood with 50 percent moisture content with approximately 4,500 Btu/lb heat content on a wet basis. Also, it has been assumed that the existing boiler cannot be reused because of its present design and the required derating would not allow the present rating of 15 MW power production. However, the balance of the plant, except for the flue gas system, can be reused. A new 69 kV transmission line and a new 20 MVA (megavolt-ampere) substation have been included to allow delivering the total plant output directly to Midwest Independent Transmission System Operator (MISO).

Two of the most proven technologies have been chosen for the estimates: stoker boiler technology and fluidized bed boiler technology.

The order of magnitude estimates presented in Table 1-4 are budgetary estimates based on published data and discussions with equipment suppliers and developers, and from B&V's database. The range of expected cost variations can be as high as ±40 percent depending on the site and system variables listed above.

1.3.8 Combined Heat and Power Opportunity

The opportunity of converting the JMEU plant into a combined heat and power (CHP) facility to provide steam to industrial or commercial facilities near the plant was considered to determine its technical feasibility and its financial merit.

Two steam users were identified by the City: Memorial Hospital & Health Care at 800 West 9th Street and Jasper Rubber Company near Truman Road and 1st Street. The City provided monthly boiler gas usage and annual gas cost for each user. The total steam requirements from these two users is 82,098,000 pounds per year and it is estimated that their cost to produce steam is approximately $13.25/mmBtu, which includes $9.43/mmBtu for natural gas price paid to the City and the remainder to account for user's plant efficiency. However, this cost does not include user's O&M cost, which was not available.

Table 1-4
Order of Magnitude Cost for 100 Percent Biomass Plants[1,2]

Biomass Requirements	**Approximately 600 Tons/Day**
Biomass Heat Input (mmBtu/h)	297.5
Steam Pressure (psig)	675
Stoker Boiler Technology	
Steam Output (lb/h)	165,000
Stoker Boiler Equipment Cost	$10,374,000
Other Equipment and Installation	$13,026,000
Total Installed Boiler System Cost	$23,400,000
Total Installed Biomass Prep-Yard	$7,590,000
Electrical Substation and Transmission Line and Miscellaneous	$5,000,000
Miscellaneous Upgrades to Existing Steam Turbine Generator	$3,000,000
Total Installed Stoker Boiler Steam Plant Cost	**$38,990,000**
Fluidized Bed Boiler Technology	
Steam Output (lb/h)	175,000
Fluidized Bed Boiler Equipment and Installation Cost	$18,837,000
Other Equipment and Installation	$13,026,000
Total Installed Boiler System Cost	$31,363,000
Total Installed Biomass Prep-Yard	$7,059,000
Electrical Substation and Transmission Line and Miscellaneous	$5,000,000
Miscellaneous Upgrades to Existing Steam Turbine Generator	$3,000,000
Total Installed Fluidized Bed Boiler Steam Plant Cost	**$46,422,000**

(1)Price does not include a new steam turbine generator. It is assumed the existing steam turbine and generator will be reused. Price for air quality control equipment for environmental compliance is not included.
(2)Estimates have a ±40 percent accuracy.

Based on annual operation of the JMEU CHP facility assuming 90 percent availability, the extraction steam would provide approximately 60 percent of the annual requirement and the remaining 40 percent of the steam requirement is provided by the boiler. The estimated annual steam energy cost is calculated as ($0.80/mmBtu x 60% + $5.47/mmBtu x 40%) = $2.67/mmBtu. It is assumed that CHP steam produced by the JMEU plant can be sold to users for about $10.60/mmBtu.

The conclusions of the high level analysis are as follows:

- It is technically possible to convert the JMEU plant into a CHP facility by extracting steam from the steam turbine to provide steam to users for their process and heating needs. The approximate cost to modify the existing facility into a CHP including the distribution system is approximately $4,000,000.
- JMEU CHP sales at $10.60/mmBtu would provide a gross profit of $7.43/mmBtu or (82,098,000 pounds per year x 1,000 Btu/lb / 1,000,000 Btu x $7.43/mmBtu) approximately $610,000.00 per year.
- The $610,000.00 gross profit will provide a simple payback in 6.5 years. However, this gross profit might have to be reduced considerably after the City subtracts the decreased revenue from selling natural gas to the users.

In conclusion, B&V does not recommend the implementation of a CHP to the JMEU plant.

1.3.9 Base Case Description

Historical base case indicates that the plant used 35,000 to 40,000 tons of coal per year with a plant annual capacity factor of 39 percent to 43 percent and annual net heat rate of about 16,400 Btu/kWh.

The base case plant operation assumes plant operation with condition based maintenance over the next 5 years or more without major upgrades or improvements.

1.3.10 Plant Valuation

B&V prepared a market valuation of the JMEU plant for the following three cases: market value “as-is,” market value with life extension improvements, and salvage value. For market value “as-is,” B&V considers both a cost based and income based valuation. The market value with life extension improvements is an income based valuation with three sales forecast scenarios: base case, high energy prices (High Energy Market) and high fuel costs (High Fuel Market). The salvage value considers both the scrap value of the plant as well as the used equipment market. Table 1-5 summarizes the results of the market valuation cases.

Table 1-5
Market Valuation Summary

Market Valuation Case	JMEU Plant Value (2010 dollars)
Valuation “As-Is”	
Cost Based “As-Is”	$6,743,000
Income Based “As-Is”	($4,544,000)
Valuation with Life Extension Improvements	
Base Case	($12,115,000)
High Energy Market	($1,513,000)
High Fuel Market	($19,807,000)
Salvage Value	
Scrap Value	$375,000
Used Equipment Value	N/A

As shown in the above, the value of the plant is very sensitive to assumptions regarding forecast energy and fuel prices. We believe the forecasts we rely on are reasonable. However, in light of the recent and historical volatility in oil and natural gas prices, energy and fuel markets have exhibited a great deal of instability. Thus depending upon the point in time the plant is valued, and the energy and fuel price levels at that time, the ultimate value of the plant may differ substantially from the above.

2.0 Condition Assessment

2.1 Introduction

The plant condition assessment was carried out by a B&V and Locke Equipment team the week of November 16, 2009. The plant was divided into the following components:

- Boiler, economizer, and grate.
- Mechanical balance-of-plant equipment.
- Electrical equipment.
- Controls equipment.

2.2 Boiler, Economizer, and Grate

The boiler was manufactured by Union Iron Works, a division of Riley Stoker Corporation in 1965 for JMEU. The boiler is rated at 140,000 lb/h at 625 psi and 825° F equipped with Riley Spreader/Stoker, waterwall tubing side walls, superheater section, generating bank tube section, multi-clone fly ash collector, economizer, and connection breeching between boiler sections and electrostatic precipitator (ESP).

2.2.1 System Configuration

The boiler inspection report by Locke Equipments Sales Company is included in Appendix A. The report includes an evaluation of the boiler and addresses internal boiler condition, tube condition, visual examination, ultrasonic tube thickness measurement and evaluation, grate inspection, tube samples taken for metallurgical evaluation, and evaluation conclusions. Boiler components and sections consist of the following:

- Bottom ash hopper with manual removal of ash.
- Riley traveling grate with refractory material and variable speed drive.
- Four Riley variable speed coal spreaders.
- Four Riley feed gate valves with control integrated to grate speed.
- Main combustion chamber with water cooled walls.
- Superheat tube bank.
- Generating tube bank.
- Multi-clone fly ash collector.
- Economizer.
- Economizer soot blower.

2.2.2 Equipment Condition and Significant Issues

The evaluation of the boiler is summarized as follows:

- The boiler appears to have been maintained properly over its operational history.
- The outside of the boiler is in good condition.
- The grate has suffered wear hindering proper airflow; this is a normal routine maintenance item.
- The water wall tubing has thinned to some degree at the higher elevations within the boiler, though probably still able to perform reasonably.
- The rear wall and the superheater pendants have significant amounts of slag buildup, greatly decreasing heat transfer and efficiency.
- The generating bank also has significant buildup and several tubes have failed requiring plugs in the headers. Both conditions greatly affect efficiency.
- The economizer has significant debris present and the lower bends have thinned excessively.
- The metallurgical condition of the tubing is normal for the materials specified.

The main concern noted during the evaluation relates to the excessive amounts of slag buildup in the superheater, the generating bank, and the economizer. It is likely that the soot blower configuration is inadequate and is not properly removing the fines allowing for the formation of slag and related debris.

In other respects, the boiler is in good condition without any evidence of metallurgical degradation, such as creep or significant corrosion, in the areas examined.

A list of recommended items for a life extension are covered later in the report.

2.3 Mechanical Balance-of-Plant Equipment

2.3.1 System Configuration

The JMEU plant consists of the following major equipment and components:

- Two 100 percent capacity vertical centrifugal condensate pumps.
- One 100 percent capacity turbine driven boiler feed pump.
- One 100 percent capacity motor driven boiler feed pump.
- Two 100 percent capacity centrifugal circulating water pumps.
- Steam jet air ejector.
- Low-pressure (LP) heater.
- High-pressure (HP) heater.
- Two condensate storage tanks.

- Surge tank.
- Deaerator.
- Two 100 percent capacity centrifugal heater pumps.
- One 14.5 MW non-reheat steam turbine.
- One 14.49 MW generator.
- One 15,000 square foot surface condenser.
- Three cell, cross-flow cooling tower.
- Electrostatic precipitator.
- Forced draft fan.
- Overfire air fan.
- Induced draft fan.
- Roots blower ash puller.
- Two bed ion exchange demineralizer.
- Riley stoker boiler and associated equipment (refer to Section 2.1).

Condensate for the steam cycle is supplied from the condenser hot well by two, 100 percent capacity condensate pumps. One pump is in operation and one pump is in standby. The pumps are cycled weekly during operation. The condensate accepts waste heat from the steam jet air ejectors, which exhaust steam to two shell and tube type heat exchangers. Condensate flows from the steam jet air ejector heat exchangers to the LP heater. The LP heater receives extraction steam from the main steam turbine through a non-return valve to heat the condensate. The LP heater level is controlled by an air-actuated level controller. Drains are returned to the condenser. Condensate flows from the LP heater to the surge tank. The surge tank acts as a holding tank and does not heat incoming condensate. The condensate is pumped by the heater pumps to the deaerator. The pumps are both 100 percent capacity pumps and are cycled weekly during operation.

The function of the deaerator is to remove noncondensable gases and to heat the boiler feedwater. The deaerator receives extraction steam from the main steam turbine through a non-return valve. Deaerator drain level is controlled by a level transmitter.

Boiler feedwater is supplied from the deaerator by two, 100 percent capacity boiler feed pumps. One feed pump is turbine driven, the other is motor driven. The plant runs on the motor driven feed pump during normal operation. According to plant personnel, full load cannot be maintained with the turbine driven feed pump due to capacity limitations. Flow to the high-pressure (HP) heater is controlled by the main feedwater control valve. The HP heater receives extraction steam from the main steam turbine through a non-return valve to heat the feedwater. The HP heater is currently used during startup and to keep the flue gas above the acid dew point temperature in order to prevent corrosion of the electrostatic precipitator (ESP). During normal operation, the

HP heater is typically bypassed in order to reduce main steam extraction and increase the output of the unit. Feedwater is sent directly to the economizer.

Steam generated in the boiler is sent to the main steam turbine. Inlet steam is controlled by a set of bar lift control valves. Control valves are actuated through the mechanical hydraulic control system located in the turbine front standard. Steam flows through the turbine and is exhausted into the condenser to complete the steam cycle. The condenser is cooled by circulating water flowing from the cooling tower by two, 100 percent capacity centrifugal circulating water pumps. Circulating water quantity is approximately 15,800 gpm. The cooling tower is a three cell, double flow, mechanical draft cooling tower with wood fill material. Circulating water is also used to cool turbine lube oil coolers, generator air coolers, and various balance-of-plant (BOP) equipment.

Water for the steam cycle makeup is provided by an onsite, two bed ion exchange demineralizer water treatment system.

The plant has a balanced draft combustion system. Primary combustion air is supplied to the stoker boiler by the motor driven forced draft (FD) fan. Overfire air fan provides additional, secondary combustion air to improve fuel combustion and to reduce the formation of nitrogen oxide (NO_x). Flue gas is drawn through the system by the induced draft (ID) fan. The flue gas flows through the ESP, which removes the fly ash by imparting a negative charge on the particulates and then collects them on grounded collecting plates. After exiting the ESP, the flue gas is drawn through the ID fan, and then exhausted to the main stack. Fly ash from the ESP is amassed in hoppers and sent to the ash storage bin through the vacuum system powered by a Roots blower. Bottom ash is collected and sent to the storage bin through the ash handling vacuum system. The collected and stored ash is hauled away by a local trucking company.

2.3.2 Equipment Condition and Significant Issues

Turbine

The steam turbine is a General Electric (GE), 14 stage, non-reheat unit rated at 14,500 kW. The unit was manufactured in the Lynn, Massachusetts facility in 1965. The unit is controlled by a mechanical hydraulic control (MHC) system located in the front standard. Spare parts availability for this system is a concern, and it is unknown if MHC spares are currently maintained by GE. The MHC system can maintain functionality with the help of machine shops to make and manufacture spare parts, and maintain desired clearances. The unit is equipped with a single stop valve and shell mounted bar lift control valves. The turbine has three extraction ports to send heating steam to the feedwater heaters. The unit receives inlet steam from the boiler at 600 psig and 825° F. While visual inspection of the steam path was not possible, inspection reports indicate that there have been no steam path or packing upgrades performed on this unit. The steam turbine control valves were fitted with stellite seats during the 1998 major inspection due to pitting. Second stage buckets were replaced during the outage as well. The last major inspection was performed in 2005. Bucket and nozzle reports indicate pitting on the inlet and discharge sides. The Number 2 diaphragm had major impact indications, and was identified for major repair in the next outage. A crack indication was found on a Stage 11 bucket. The tip of the trailing edge was removed by the contractor to prevent crack propagation. The 2005 outage report data sheets indicate some packing was replaced, but there is no indication of replacement in the renewal parts section of the writeup.

Generator

The generator is a GE air-cooled machine rated at 16.1 MVA and 14.49 MW at 0.90 power factor. Air is cooled by four circulating water supplied air coolers. The rotating excitation system has been retrofitted with a GE EX2000 static excitation system.

A significant amount of major maintenance has been performed on the generator since the 1993 inspection. The rotating exciter was upgraded to an EX2000 static exciter in 1993. The generator field retaining rings were upgraded to 18Mn-18Cr during the 1993 upgrade. The generator stator was rewound in 2000 following an in-service failure. The insulation was upgraded from Class B (80° C rise) to Class F (105° C rise). The generator field was rewound in 2005 because of an in service failure of a top stator bar that caused a short in the field. The field was rewound with new copper in accordance with a recommendation by National Electric Coil. Due to the higher temperature rise capability of Class F insulation, the unit has been uprated to approximately 18 MVA following field and stator rewinds.

Pumps

BOP pumps are configured redundantly, with each pump capable of 100 percent system capacity. The pumps are cycled weekly during operation.

Two, 100 percent rated capacity boiler feed pumps are currently installed. One feed pump is turbine driven, and one motor driven. The turbine driven feed pump is currently de-rated, and not capable of supporting the plant at 100 percent load according to the plant superintendent. The motor driven boiler feed pump is capable of supporting the feedwater needs of the plant at 100 percent load, and is operated during normal operation. These pumps are not cycled with the rest of the BOP pumps. Pump motors are rewound when they fail by a local motor repair shop. Pump repairs are made by the maintenance staff. The redundant configuration allows for online maintenance of the standby pump and driver.

Fans

The American Standard FD fan is driven by a two-speed 75 horsepower (hp) Westinghouse motor. The fan and motor are original equipment. A new damper controller was installed in 1994. No information was available about FD motor repair or refurbishment.

A Zurn Industries ID fan is driven by a 500 hp GE motor with a Halmar Robicon Group variable frequency drive. The fan, motor, and drive were installed new in 1993.

The Clarage overfire air fan is driven by a 60 hp Westinghouse motor and was installed in 1993.

All fans and motors are maintained under the plant's condition based maintenance program and appeared to be in good condition. No significant issues were noted during the site visit.

Cooling Tower

The cooling tower is a Marley Class 600 three cell, cross-flow mechanical draft cooling tower. New cooling tower fan stacks were installed during the 1993 upgrade. Twenty-five percent new wood fill material was added at this time. New support structure wood was added at this time, where needed. The cooling tower fan motors and gear boxes are currently under a condition based maintenance plan. The fill material is wood lathe, and through visual inspection, appears to be in poor condition. Many wood splash bars are broken and rotted, affecting heat exchange and thermal performance.

Coal Handling Equipment

The plant coal handling equipment consists of a bucket elevator, feeder conveyor belts, and a traveling tripper conveyor that delivers coal to a single silo. There are four coal feeders that provide coal to the boiler. The conveyor rollers are greased monthly and replaced periodically. The elevator buckets have been replaced twice since the original system was installed. The bucket elevator drive chain has been replaced once. The upper conveyor belt was replaced in 1993. The lower conveyor belt was replaced approximately 20 years ago. All of the coal handling equipment motors are original equipment. The tripper cart underwent a hydraulic retrofit in 1998, but is not currently functional, and is used as a stationary tripper. The storage silo is filled by dumping coal through the tripper, which is positioned in the middle of the bin. Coal scales are no longer in place and the coal usage is determined monthly by delivery weight information.

Electrostatic Precipitator

The ESP was installed during the 1993 plant upgrade. The ESP has 12 gas passages spaced 12 inches apart with a design temperature rating of 475° F. Design flow through the ESP is 102,760 acfm (actual cubic feet per minute). Design inlet particulate matter concentration is 5 lb/mmBtu, and design outlet concentration is 0.1 lb/mmBtu with a guaranteed collection efficiency of 98 percent. Emissions testing was performed on the ESP in June 2009. The average particulate matter emissions rate was 0.0294 lb/mmBtu, which equates to a collection efficiency of greater than 99 percent.

Ash Handling Equipment

The ash handling equipment consists of a Roots blower, baghouse, and paddle mixer. Bottom ash and fly ash are collected in hoppers and pulled through ash handling piping with vacuum pressure created by the Roots blower. The ash is sent to the bag house and funneled into the ash hopper. The ash handling system was upgraded during the 1993 outage with replacement of the Roots blower ash puller with a new unit. A significant amount of ash piping was replaced during the outage as well. The ash unloader was replaced with a new paddle mixer unit during the 1993 outage. In 1998, the right hand paddle shaft was replaced.

Condenser

The steam cycle condenser is a Worthington horizontal, divided two pass condenser with 15,000 square feet of surface area. It is designed to operate with a backpressure of 1.5 inches Hg absolute. The condenser receives steam from the steam turbine exhaust as well as condensate from various drains. The design rated heat duty of the surface condenser is 112 mmBtu/h with a circulating water quantity of 15,800 gpm (gallons per minute) from the cooling tower. The condenser currently has approximately 100 plugged tubes due to tube leaks, representing 3 percent of installed tubes.

Water Treatment

Water treatment is accomplished through a Hungerford & Terry two bed ion exchange demineralizer system. The first bed uses a cation exchanger with acid regeneration for removal of calcium, magnesium, and sodium. The second bed uses an anion exchanger with caustic regeneration for removal of alkalies, chlorides, sulfates, silica, and carbon dioxide. The system has a capacity of 20,000 gallons per regeneration and is capable of approximately 25 gpm. The anion and cation resins were replaced in 1999.

Feedwater Heaters and Deaerator

The plant operates with a LP heater and a deaerator. The HP heater is typically taken out of service or bypassed during operation to improve overall plant output. The LP heater receives extraction steam from the third turbine extraction steam port. The deaerator receives extraction steam from the second turbine extraction port. The LP heater drain level is controlled by a float connected to a pneumatic controller. The deaerator level is controlled by a level transmitter. Maintenance records were not available for the feedwater heaters and deaerator.

Air Compressors

The plant is equipped with two, vertical reciprocating Ingersoll Rand air compressors, one horizontal reciprocating Ingersoll Rand air compressor, and one Sullivan-Palatek high efficiency rotary screw air compressor. The plant primarily operates using the new rotary screw air compressor, which was installed in 2007. The rotary screw air compressor has a capacity of 115 acfm. The reciprocating air compressors are original plant equipment and are used as standby sources only.

2.4 Electrical Equipment

2.4.1 System Configuration

The 14,500 kW generator feeds electrical power to 13.2 kV metal-clad switchgear labeled Bus No. 1. From Bus No. 1, electricity is fed into three overhead distribution lines labeled Express, Skyline, and Industrial. The distribution circuits exit the bottom of the switchgear and extend underground to the poles where they tap into the overhead lines.

The 13.2 kV switchgear also feeds the plant auxiliary loads through House Service Substations 1 and 2. House Service Substation 1 is dedicated to loads in the building and House Service Substation 2 is located at and serves the cooling tower loads.

2.4.2 Equipment Condition

Overall, the electrical equipment is well maintained and in good condition and capable of continued operation. It should be noted that in consideration of the age of the unit, equipment reliability can decrease and unexpected failures could occur as the age of the equipment increases over 40 years. In some cases, the availability of spare parts could become limited, as the original equipment manufacturers can no longer support the equipment. This is common for all units of this type and age.

13.2 kV Switchgear Bus No. 1

The 13.2 kV switchgear Bus No. 1 was manufactured by GE and is the original equipment. There are four breakers; one for the generator and three for the three distribution feeders. The breakers are GE's MagnaBlast air break type. There are also two fused switches feeding the two house service substations. The switchgear still has the original electromechanical protective relays.

The switchgear was designed to support a second generator in the future. Therefore, there is a tie breaker section. However, there is no breaker in the tie breaker section.

According to staff, the switchgear is inspected every 5 years, and the breakers were reworked about 7 years ago. Parts are still available to maintain the electro-mechanical relays. Companies in Louisville and Evansville do repairs on the switchgear. The switchgear appears to be in good shape for its age.

Secondary Unit Substations

There are two secondary unit substations designated as 480 Volt House Service Substation No. 1 and No. 2.

House Service Substation No. 1 was manufactured by Westinghouse. The switchgear is the original equipment. However, the step-down transformer was replaced in 1994 because the original transformer had polychlorinated biphenyls (PCBs) in the insulating oil. The new transformer was manufactured by ABB. It is rated 1,500/1,680 kVA, 55/65° C rise, 13,200-480 V and is configured delta-delta. The impedance is 9.38 percent. The switchgear appears to be in average shape for its age.

House Service Substation No. 2 was manufactured by Westinghouse. The switchgear is the original equipment. The transformer was manufactured by Westinghouse. It is rated 1,000/1,120 kVA, 55/65° C rise, 13,200-480 V and is configured delta-delta. The impedance is 5.8 percent. The switchgear appears to be in average shape for its age.

The insulating oil in the step-down transformer was replaced in 1994 because the original transformer oil had PCBs. The switchgear is enclosed in a weatherproof enclosure and could not be inspected visually. It is assumed that it is in the same condition as House Service Substation No. 1.

Motor Control Centers

There are three motor control centers (MCCs); two arranged back to back on the turbine deck floor and one associated with the precipitator. The two MCCs on the turbine deck were supplied by Cutler Hammer and are the original equipment. The MCCs are approximately 42 years old and are approaching the end of their service life. Visually, the MCCs appear to be clean and in relatively good shape for their age. Cutler Hammer no longer supports this vintage of MCC, but custom retrofit starters and breakers are available. According to staff, several breakers have been replaced on an as required basis. The bucket space on this issue of MCCs appears to be limited and it may be difficult to install retrofit starters in the limited space.

The MCC associated with the precipitator was installed in 1992 and is therefore 17 years old.

Maintenance is performed on the MCCs on an as required basis.

Large Motors

The large motors appear to be in good condition. The large motors are tested annually and repaired as required. The small motors are replaced when they fail. Five large motors have been rebuilt including the following:

- Three cooling tower fan motors.
- The circulating water pump motor.
- The feedwater pump motor.

Cables

The 480 volt cables in the plant are original. Most of the 480 volt cables are in conduit and were not visible for inspection.

The interconnection between the generator output and the 13.2 kV switchgear Bus No. 1 is by 15 kV, 750 mcm, Vulkene insulated power cable manufactured by GE. The 15 kV cable is routed in cable tray and appears to be in good condition.

The feeders from the 13.2 kV Switchgear Bus No. 1 out to the overhead distribution lines are also original.

Battery and Battery Charger

The batteries were replaced in February 2008. The battery cells are flooded lead acid and are designated as having 20 year life. The batteries are inspected quarterly.

The battery charger is an Exide motor generator set. The motor and generator set appear to be in good condition. The motor and generator are tested annually.

The control/distribution cabinet was manufactured by Exide and is the original equipment. The control/distribution cabinet appears to be in average shape considering its age.

Uninterruptible Power Supply

The uninterruptible power supply provides power for the electrical plant control systems. The uninterruptible power supply is 5 kVA and was installed in 1993. The uninterruptible power supply was manufactured by Solid State Controls, Inc. The uninterruptible power supply appears to be in average condition considering its age.

The backup battery for the uninterruptible power supply consists of valve regulated (sealed) cells. The battery is 125 volts. The battery cabinet sits on the west side of the building and gets heated by the afternoon sunshine. A window type air conditioner is rigged to blow cold air into the battery cabinet to keep the batteries cool.

2.5 Controls Equipment

2.5.1 System Configuration

The plant control equipment is divided into the following individual control systems.

Boiler Control System

This control system handles the boiler combustion process and the original system consisted of pneumatic system manufactured by the Bailey Meter Company. In 1993, a partial upgrade to this system was implemented by replacing some of the field transmitters with electric analog transmitters and a new NET 90 distributed control system (DCS) was manufactured by the Bailey Controls Company to handle the combustion controls logic. However, most of the pneumatic gauges and recorders stayed to date in the original panel in the control room. In the late 1990s, the coal scales were removed from the boilers and new variable coal feeders were installed and interfaced to the logic in the NET 90 system.

Turbine Control System

This system is covered in detail in Subsection 2.2.2.

Condenser Control System

This system is covered in detail in Subsection 2.2.2.

Coal Handling Control System

This system consists of an operator controlled manual push-button panel located in the basement area of the plant. Electrical interlocks between the equipment motor starters are provided to ensure sequential operation of equipment and to provide for a unit or system shutdown during abnormal operating conditions.

Ash Handling Control System

This system consists of an operator controlled manual push-button panel located in the basement area of the plant. Electrical interlocks between the equipment motor starters are provided to ensure sequential operation of equipment and to provide for a unit or system shutdown during abnormal operating conditions.

2.5.2 Equipment Condition

In general, the boiler control equipment condition is good considering the age of some of the components. However, the NET 90 system is obsolete and replacement parts and service will become harder to find. The coal handling and ash handling control systems are aging and as the electrical distribution system is upgraded, these systems will also require upgrading.

2.5.3 Significant Issues

The boiler combustion control system field instrumentation consists of a mix of new electronic (4-20 mA) transmitters and also some of the original pneumatic transmitters containing mercury. These pneumatic transmitters require considerable maintenance to keep them in calibration and, because of the mercury, they should be replaced as soon as possible with new state of the art electronic transmitters. In addition, all the self-contained control loops with pneumatic transmitters and positioners should be replaced.

3.0 Life Extension Upgrades

3.1 Boiler, Economizer, and Grate

Boiler evaluation determined the boiler components and sections that need improvements or upgrades to extend the life of the boiler and improve boiler performance. The improvements and upgrades are listed as follows:

1. A Detroit Stoker representative should be scheduled to adjust grate seals and replace worn links. This work would cost approximately $30,000.
2. Chill row tubes along both sides of the grate should be replaced. The boiler has eight tubes total. The chill tube thicknesses are currently adequate, but are typically high wear items and replacement should be considered within the next 2 to 3 years. This would cost approximately $25,000.
3. Performance and service life should be improved by the addition of steam or sonic soot blowers in the generating bank and economizer. The cost would be as follows:
   - Economizer: Add four rotary steam soot blowers at $100,000.
   - Generating Bank: Add four rotary electric steam soot blowers at $135,000.
4. The generating bank tubes should be replaced. If long-term operation of the plant is considered, the tube replacement should be considered for reliability. The work can be completed in phases if budgeting concerns prevent complete replacement at one time. The work should be completed in the next 5 to 10 years. It is practicable to complete the re-tube process in two phases with the center soot blower lane as the dividing line between phases. Tube plugs are present in approximately 4 percent of the generating bank tubes. The ultrasonic thickness measurements suggest that a much greater number of tubes have thinned significantly. The total cost replacing the entire generating bank is approximately $350,000.
5. The economizer return bends (180 degree) show measured signs of erosion or metal loss. The cold end tube Rows 12, 13, 14, and 15 can be replaced for $45,000. This tube replacement should be considered within the next 3 years.
6. Superheater brackets are recommended to maintain alignment spacing in a uniform manner. Also, modern bracket equipment controls expansion direction so all movement is vertical in the pendant superheater elements. When the elements move out of plane, flow restrictions occur.

Additionally, slag accumulation increases due to blocking of the normal flow paths. When flow is blocked in one area, other areas experience increased velocities and erosion acceleration. Installation of cast alloy support devices will cost approximately $50,000 consisting of two rows of support castings.

7. Waterside acid cleaning is recommended in the next few years of operation. A water chemist should be consulted for specific chemical cleaning methods. Scale appears to be accumulating. The removal process could be accomplished by an online process or by an acid cleaning contractor with an estimated cost of $50,000 to $100,000. The cleaning chemicals may be disposed of through the city, but a thorough review with the city water engineer is warranted prior to the cleaning operation.

3.2 Mechanical Balance-of-Plant Equipment

3.2.1 Turbine

Design turbine thermal efficiency of this unit is approximately 80 percent. In order to improve efficiency, leakage losses should be minimized. New turbine blade cover and nozzle spill strip designs are available, which would greatly reduce turbine blade tip leakage losses. New interstage and end packing will reduce packing leakage losses, resulting in more steam available to power the turbine blades. Retractable packing and brush seal packing designs are available from various manufacturers, which aim to reduce leakage losses even further from original designs. This retrofit can improve turbine efficiency by up to 2 percent and net plant heat rate by 0.8 percent.

A major outage should be performed on the steam turbine. Interstage packing can be refurbished by several manufacturers for a fraction of the cost for new packing. Turbine buckets and diaphragm profiles should be blended by a technician to reduce blade profile friction losses. A radial spill strip upgrade should be performed to increase turbine stage efficiency. This will require new bucket covers and diaphragm spill strips.

3.2.2 Generator

Because of the degree of major maintenance performed on the generator in recent years, B&V does not recommend any additional major maintenance beyond the planned maintenance inspections in the near future. High potential testing, leakage, and field insulation resistance tests should be performed at every major inspection at 5 year intervals.

3.2.3 Pumps

In order to bring the BOP pumps to a fully redundant configuration, the turbine driven boiler feed pump should be replaced with a motor driven configuration. This will increase plant reliability by having two boiler feed pumps capable of supporting full plant load.

The current maintenance plan for the remaining BOP pumps and motors is adequate for continued operation.

3.2.4 Fans

The current maintenance plan for the fans and motors is adequate for continued operation. There are no recommendations for fan improvements or upgrades at this time.

3.2.5 Air Compressors

B&V does not recommend any upgrades to the air compression system. Regular maintenance should be performed on the rotary screw air compressor. The reciprocating air compressors should be maintained as backup sources.

3.2.6 Cooling Tower

To support continued operation for the next 20 years, B&V recommends rebuilding the cooling tower. Fill material was identified for replacement, but cooling tower rebuild with labor was approximately 75 percent of the cost for a new cooling tower. Cooling tower thermal efficiency will be improved with a rebuild. New fill materials will be used, which will increase cooling tower reliability, and decrease O&M costs.

3.2.7 Coal Handling Equipment

The coal handling starting sequence is currently controlled manually. B&V recommends automating the coal handling system with a programmable logic controller (PLC). The traveling tripper hydraulic control system should be replaced with a functional and reliable system.

3.2.8 Electrostatic Precipitator

B&V does not recommend any upgrades or improvements to the ESP. The ESP underwent emissions testing in June 2009, with particulate collection efficiency greater than 99 percent.

3.2.9 Ash Handling Equipment

The ash handling equipment is well maintained and currently under the plant's condition based maintenance program. B&V does not recommend any upgrades to the ash handling system.

3.2.10 Condenser

To ensure adequate thermal performance, a major inspection should be performed on the condenser. The condenser tubes should be cleaned, eddy current tested, and failed tubes should be replaced. Replacement of leaking or plugged tubes can lead to increased unit performance because of an increase in condenser vacuum and a decrease in turbine backpressure. Condenser cleanliness improvement of 10 percent results in a 0.15 inch Hg turbine backpressure reduction and 0.1 percent net plant heat rate improvement.

Though the use of city water decreases condenser tube fouling, some scale accumulation is expected. Future condenser tube cleanings should occur annually to maintain thermal performance.

3.2.11 Feedwater Heaters and Deaerator

The LP feedwater heater and deaerator tubes should be eddy current tested during the annual boiler inspection. A visual inspection of the tubesheet, channels, and pass partition plate covers should be performed as well.

3.2.12 Water Treatment

The anion and cation exchange resins should be replaced when necessary based on testing of makeup water and ion exchange resin. Resin testing should be performed on an annual basis. Makeup water testing should be performed on a weekly basis.

3.2.13 Fire Protection System

There is not currently a fire protection system installed at the plant. A fire protection system should be installed that conforms to NFPA 850; Recommended Practice for Fire Protection for Electric Generating Plants and High Voltage Direct Current Converter Stations. The fire protection control panel can be interconnected with the recommended GE Mark VIe digital control system. The fire protection system will require interconnection with the coal handling system, ash handling system, and additional equipment and systems as identified during detailed design.

A dust collection system should be installed to handle combustible coal dust generated in the coal handling system. The dust collection system should be interconnected to the fire protection system.

Temperature sensors should be installed at the inlet and outlet ducts of the ESP. The area under the turbine generator floor subject to oil accumulation should be protected by an automatic sprinkler system. Lubricating oil lines on the turbine generator floor should be protected by an automatic sprinkler system, including lubricating oil lines running underneath the turbine lagging. The turbine generator bearings should be protected by an automatic closed head sprinkler system utilizing directional nozzles to prevent accidental water discharge.

3.3 Electrical Equipment

3.3.1 13.2 kV Switchgear Bus

The GE MagnaBlast breakers are no longer available. However, replacement breakers can most likely be obtained on the used equipment market. In addition, the breakers can be retrofitted with new vacuum break breakers. However, if the plant is expected to undergo a major upgrade so that it operates as a baseload unit, then it is recommended that the entire switchgear bus be replaced with new switchgear instead of just being refurbished. In addition, new electronic multifunction relays should be provided with the new switchgear.

3.3.2 Secondary Unit Substations

The breakers that are in the switchgear are no longer manufactured. However, retrofit breakers could be obtained to replace breakers on an as-required basis. Some work was done to the switchgear in House Service Substation No. 1 when the precipitator was added. According to staff, the switchgear is inspected every 5 years. However, if the plant is expected to undergo a major upgrade so that it operates as a baseload unit, then it is recommended that the switchgear be replaced with new switchgear. The step-down transformers should be serviceable for an additional 20 years and do not need to be replaced.

3.3.3 Motor Control Centers

If a major upgrade is made to the plant, then the MCCs on the turbine deck should be replaced in order to extend the reliable operation life of the plant for an additional 20 years. The MCC that serves the precipitator appears to be in good shape and should be serviceable for an additional 20 years.

3.3.4 Large Motors

The large motors appear to be in good condition and should be serviceable for an additional 20 years. Motors that indicate problems during the annual testing can be repaired as required.

3.3.5 Cables

The 480 volt cables in the plant should be serviceable for an additional 20 years. Several of the cables could be tested to determine their condition in order to predict if they are near failure. However, there is difference of opinion about maintenance testing of cable. Old cables, that would otherwise render long trouble-free service at normal voltage, are often damaged during testing. In addition, 480 volt cables are relatively easy to replace so that any plant outage because of cable failure would be short. If significant numbers of 480 volt cables start to fail, then this aspect should be revisited, and a cable replacement program should be instigated.

The 15 kV cable interconnection between the generator output and the 13.2 kV Switchgear Bus No. 1 is a critical section of cable. B&V recommends that this section of cable be tested if the plant is expected to provide reliable operation for an additional 20 years. Also, these cables may be damaged when the 13.2 kV switchgear is replaced.

The feeders from the 13.2 kV Switchgear Bus No. 1 out to the overhead distribution lines are not as critical as the generator leads, but could be tested at the same time that the generator leads are tested. Also, these cables may be damaged when the 13.2 kV switchgear is replaced.

3.3.6 Battery and Battery Charger

The batteries were replaced in 2008 and should be serviceable for most, if not all, of 20 years. The batteries can be tested on a regular basis and replaced on an as-needed basis.

The battery charger motor generator set should be serviceable for an additional 20 years, but can be repaired or replaced as required.

The control/distribution cabinet should be serviceable for a few more years, but can be repaired or replaced as required.

B&V recommends that the batteries be enclosed in a battery room and that the room be vented outside the building.

3.3.7 Uninterruptible Power Supply

The uninterruptible power supply was installed in 1993. Uninterruptible power supplies of that vintage have a life expectancy of approximately 15 years. As such it should be replaced if the plant is expected to undergo a major upgrade.

The backup battery for the uninterruptible power supply consists of valve regulated (sealed) cells. The battery is 125 volts. Sealed battery cells typically have an expected life of 3 to 10 years, depending on the quality of batteries installed. The battery cabinet is located on the west side of the building and gets heated by the afternoon sunshine. A window type air conditioner is rigged to blow cold air into the battery cabinet to keep the batteries cool. These batteries should be replaced with the uninterruptible power supply.

3.3.8 Black Start Standby Diesel Generator

The plant currently does not have a standby diesel generator. The plant total auxiliary load is approximately 930 kW. Not all of the total auxiliary load would be required to get the plant started. For instance, the coal handling and one of the circulating water pumps would not be required for starting. However, the generator would have to start the large ID fan without having excessive voltage drop. In order to have sufficient black start capability, it is estimated that the plant would require a diesel generator of approximately 1,000 kW to 1,200 kW.

There is a spare compartment in the House Service Substation No. 1 that was intended to be a tie breaker to a future house service substation. That breaker could be used as a location to inject the power from the diesel generator.

Under the present 480 volt system configuration, injecting the black start diesel generator capacity onto the House Service Substation No. 1 bus would not provide power to the cooling tower area, which is fed from House Service Substation No. 2. House Service Substation No. 2 feeds the cooling tower fans and the circulating water pumps. In order to get power to House Service Substation No. 2, power would have to be back fed from the diesel generator up through the transformer that feeds House Service Substation No. 1 to the 13.2 kV switchgear. Then power would flow as normal from the 13.2 kV switchgear to House Service Substation No. 2.

Since the 13.2 kV switchgear bus is energized by the diesel generator, the plant generator would have to synchronize with the diesel generator. Due to the vast size difference between the two generators, the generator paralleling system in the new House Service Substation No. 1 switchgear will need to be equipped to handle this task.

3.3.9 69 kV Transmission Line

The largest electrical issue associated with operating the plant as a baseload unit is its electrical connection to the distribution system. Presently, the plant power is fed into three overhead distribution lines; Express, Skyline, and Industrial. Typically, these three lines have less load than the generator output. Some of the generator production flows back into the Central Tie Substation. Once delivered to the Central Tie Substation, this additional power serves the load on the loop feeder and the innerloop feeder. Even with these two additional feeders, the load is often less than the generator capacity. Therefore, some of the excess generator capacity would have to backfeed through the 69 kV to 13.2 kV transformer out onto the 69 kV system.

Backfeeding out of the central tie substation has caused JMEU problems in the past. For this reason, B&V investigated installing a generator step-up transformer at the plant. This transformer would step the generator voltage up to 69 kV and inject the power on the 69 kV system (bypassing the Central Tie Substation). It was assumed that the existing tie breaker section on the 13.2 kV switchgear could be used to feed a new generator step-up transformer. The section is existing, but a new breaker would be required. The step-up transformer could be installed south of the plant. An overhead 69 kV line would have to be installed to intersect the existing 69 kV system.

Two 69 kV line routes were investigated. The most direct route would be to install the 69 kV line west, down 15th Street to Mill Street where the existing 69 kV line runs north/south between the North Tie Substation and the Central Tie Substation. A sectionalizing switch would have to be installed at the corner of 15th Street and Mill Street to tie the two lines together. The 69 kV line would be approximately 0.8 miles. This line is the most direct route, but it also runs through a residential area. Since this route would disrupt the residents on 15th Street, a second route was investigated.

For the second route investigated, the line would travel north out of the plant through the industrial area on Cherry Street, Cathy Lane, and 30th Street over to Mill Street near the North Tie Substation. A sectionalizing switch would have to be installed near 30th Street and Mill Street to tie the two lines together, or the line could be run directly into the substation. This route is approximately 1.6 miles, or twice as long as the more direct route. However, this route runs through industrial and rural areas and would not disturb the residents along 15th Street. Although the line is twice as long, it is estimated that since the line would be easier to install, the cost would be approximately the same.

3.4 Control Equipment

The most efficient and cost effective way to upgrade the boiler combustion, coal handling, ash handling and other plant miscellaneous controls system is to integrate them all with the new turbine controls. The turbine control system should provide all the hardware for the new DCS and the remainder of the upgrade would consist of new field instrumentation field devices, field control wiring, interface, programming, and commissioning.

3.5 Capital Cost Forecast

An order of magnitude, total installed cost estimate for the life extension upgrades including the mechanical, electrical, and control projects was prepared. The cost estimate includes equipment, installation, testing and commissioning, general conditions, engineering, and contingency. The order of magnitude cost estimate is expected to be within plus or minus 40 percent of the actual installed cost. The order of magnitude cost estimate is shown in Table 3-1. The life extension budget cost provided in Table 3-1 is used in Section 11.0 for the plant valuation analysis.

Table 3-1
Life Extension Projects and Budget Cost

Item	Qty.	Unit	Description	Order of Magnitude Cost Estimate
1	1	LS	13.2 kV Switchgear Bus	$1,185,000
2	1	LS	House Service Substation Switchgear	$863,000
3	1	LS	Motor Control Centers	$283,000
4	1	LS	Uninterruptible Power Supply	$45,000
5	1	LS	Black Start Standby Diesel Generator	$578,000
6	1	LS	MARK Vie Total Plant Control System	$585,000
7	1	LS	Balance-of-Plant Controls Upgraded and Integrated into Steam Turbine Generator Control Upgrade	$500,000
8	1	LS	Detroit Stoker Grate, Seals, and Link Repairs	$30,000
9	1	LS	Replace Eight Chill Tubes Each Side of Grate	$25,000
10	1	LS	Replace Economizer U Bends and Cold End Tubes Rows 12, 13, 14, and 15	$450,000
11	1	LS	Boiler Economizer (4) Soot Blowers	$100,000
12	1	LS	Boiler Generating Bank (4) Electric Rotary Soot Blowers	$135,000
13	1	LS	Boiler Generator Bank Replacement	$350,000
14	1	LS	Super Heater Tube Alignment and Bracket Repair, Some Tube Replacement to Reduce Blockage and Velocity Issues	$50,000
15	1	LS	Boiler Water Side Acid Cleaning and Flashing	$100,000
16	1	LS	Steam Turbine Packing Refurbishment, Spill Strip Upgrade	$153,000
17	1	LS	Cooling Tower Rebuild	$225,000
18	1	LS	Boiler Feed Pump Motor	$45,000
19	1	LS	Traveling Tripper Hydraulic Repair	$13,500
20	1	LS	Condenser Eddy Current - Tube Replacement	$22,500
21	1	LS	Feedwater Heater/Deaerator Eddy Current Testing	$9,000
22	1	LS	Fire Protection System (Detection and Sprinklers in accordance with National Fire Protection Association [NFPA])	$40,500
23	1	LS	Dust Collection System (Ventilation Coal Areas and Cleaning)	$103,500
24	1	LS	Condenser Eddy Current - Tube Replacement	$22,500
25	1	LS	Generator Step-up Transformer and Transmission	$2,786,000
27			**Construction Direct Subtotal**	**$8,699,500**
28		10.0%	Contingency	$869,950
			Subtotal, Direct Construction	**$9,569,450**
Indirect Costs				
		2.0%	Testing and Commissioning	$191,389
		3.0%	General Conditions, Fee, Insurance, Mobilization	$287,084
		8.5%	Engineering and Design	$813,403
			Subtotal, Indirect Costs	**$1,291,876**
			Grand Total	**$10,861,326**

4.0 Environmental Assessment

4.1 Background

The JMEU operates a 192 mmBtu/h coal fired spreader stoker boiler, constructed in 1967, which is used to generate electricity. The power plant is located in Dubois County, Indiana. The boiler is also equipped with a 60 mmBtu/h natural gas fired low NO_x burner (LNB) that is used during startup. A multi-clone and an ESP control particulate emissions. The boiler was placed into service in 1968 and has a peak output of 14.5 MW. The power plant fires Indiana bituminous coal, which is stored outside in a outdoor storage pile that is equipped with covers. The storage pile has a capacity of 810 tons, and the maximum annual throughput is limited to 74,666 tons per year (tpy). The ash handling system consists of an ash storage silo, with a storage capacity of 300 tons, and is equipped with a pulsejet baghouse to control particulate emissions. The maximum annual throughput of ash is 7,540 tpy.

The JMEU plant currently operates under a Title V (Part 70) Permit (Permit No. T 037-22741-00002) issued by the Indiana Department of Environmental Management (IDEM) on October 3, 2008. The Title V permit classifies the JMEU plant as an existing major source under NNSR/PSD rules.

The Title V permit also classifies the plant as a major source of hazardous air pollutants (HAPs), with the emissions of hydrogen chloride (HCl) greater than 10 tpy. Being a major source of HAPs, the JMEU plant will be subject to the requirements of the Industrial Boiler Maximum Achievable Control Technology (Boiler MACT) rule. Since the facility generates less than 25 MW of electricity for sale, it is not subject to the acid rain requirements.

As outlined previously in this report, B&V has been tasked to perform a plant assessment study to determine the present condition of the plant and to analyze potential upgrades to the plant including biomass co-firing and/or CHP opportunities. The plant upgrades being considered will increase the remaining life of the plant and would result in a higher utilization of the boiler. There will, however, be no increase to the rated peak output capacity of the steam turbine. This air permitting assessment qualitatively analyzes whether any potential plant improvements, i.e., life extension projects, could potentially trigger major source PSD review. Once a preliminary PSD applicability determination has been made, a more detailed analysis of the permitting issues identified in this report along with a comprehensive look at the facility conceptual design and emission profile would be needed to finalize the air permitting strategy.

4.2 Air Quality Characterization

The air quality in a given area is generally designated as being in attainment for a pollutant if the monitored concentrations of that pollutant are less than the applicable National Ambient Air Quality Standards (NAAQS) or if the area is considered unclassifiable for that pollutant. Likewise, a given area is generally classified as nonattainment for a pollutant if the monitored concentrations of that pollutant in the area are above the NAAQS. A review of the air quality status in the region reveals that Dubois County is classified as a nonattainment area for $PM_{2.5}$ and an attainment or unclassifiable for all the other criteria pollutants.

The nearest mandatory Class I area is Mammoth Cave National Park, which is located within 200 km (kilometers) from the facility.

4.3 Air Construction Permitting: Qualitative Assessment

Prior to the installation, modification, or alteration of an air emission source in Indiana, an air construction permit must be obtained from the IDEM. It is through the air quality permitting process that the state and federal NSR air quality permitting regulations are implemented.

The federal Clean Air Act (CAA) NSR provisions are implemented for new major stationary sources and major modifications to existing sources under two programs; the PSD program and the NNSR program, which are outlined in 40 Code of Federal Regulations (CFRs) 51 and 52. As mentioned earlier, the JMEU plant is an existing major PSD source under IDEM regulations. Major source NNSR/PSD would apply if the proposed plant upgrades will result in a major modification.

Issues related to applicability of NNSR/PSD to boiler upgrade/life extension projects typically require a case-by-case consideration of the term "modification" as defined under the CAA. Once a project is determined to be a modification, then further analyses can be completed to determine if a modification is a "minor modification" or a "major modification" under NNSR/PSD. As mentioned earlier, major source NNSR/PSD review will apply if the modification is deemed to be major. The trigger levels for minor and major modification are discussed later in this report. The CAA defines "modification" as, "Any physical change in, or change in the method of operation of, a stationary source which increases the amount of air pollution emitted by such source or which results in the emissions of any air pollutant not previously emitted." Since implementation of any or all of the above listed projects is a "physical change," and would result in a "change in the method of operation," it appears that these projects meet the first part of the definition of modification. The second part of the definition of "modification" requires affected facilities to establish if there is going to be an increase in emissions. For the JMEU plant, this is accomplished by calculating an emissions change from the proposed project(s). Although it may appear that the proposed upgrade projects will not result in an increase in heat inputs and permitted potential-to-emit (PTE), IDEM and the Environmental Protection Agency (EPA) require affected facilities such as JMEU to calculate emissions change based on past actual operations and future actual (or potential) operations.

4.3.1 Calculating Emissions Change from a Modification

The PSD program establishes requirements for existing major PSD sources of air pollutants to undergo preconstruction review for major modifications. The regulatory definition of a major modification is “any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase of a regulated PSD pollutant; and a significant net emissions increase of that pollutant from the major stationary source.”[1] The PSD program sets forth specific threshold levels, referred to as significant emission rates (SERs) that are used to determine if an emissions increase constitutes a significant emissions increase for each PSD pollutant. The PSD SERs for PSD pollutants that are typically of concern for facilities with coal fired units are summarized in Table 4-1.

Table 4-1
PSD Significant Emission Rates

Pollutant	Significant Emission Rate, (tpy)
PM	25
PM_{10}	15
$PM_{2.5}$	10
NO_x	40
SO_2	40
CO	100
VOC	40
Sulfuric Acid Mist	7
Lead	0.6
Fluorides	3

[1] 40 CFR 52.21(b)(2)(i).

At existing major PSD sources such as the JMEU plant, PSD is applicable if the emissions change results in both a significant emissions increase and a significant net emissions increase. As previously noted, the emissions increase is determined by use of a future Projected Actual Emissions (PAE) to past Baseline Actual Emissions (BAE) comparison. The definitions of these terms, given below, are important in understanding the PSD applicability analysis.

Baseline Actual Emissions

BAE are defined as the level of emissions from a source that actually occurred over any consecutive 24 month period during the 5 year period for Electric Utility Steam Generating Units (EUSGU); or a 10 year period for non-EUSGUs, immediately prior to a specific project.

Projected Actual Emissions

For existing emission units affected by a project, the PAE are their maximum projected annual emissions over the 5 or 10 year period following the project. Whether to use a 5 or 10 year forward-looking period is dependent on the nature of the project. The PAE and BAE values are used to determine the emission increases from the project to use in the PSD applicability analysis. In general, emission increases included in the post-project PAE that are due to the normal expected increase in demand growth and would be achievable without the project are considered excludable emissions (EE) and do not have to be considered in the project emissions increase calculation. However, emission increases associated with increased emission unit capacity or increased unit utilization that is attributable to the project must be included in the emissions increase calculation.

Under the above discussed definition/methodology, one would compare a modified unit's BAE before the change with its PAE after the change to determine if a physical or operational change would result in a significant increase in emissions, and thus subject it to PSD. Major modifications that result in significant emissions increases are subject to PSD review, possibly including the following:

- Implementation of BACT.
- Increment analysis (air dispersion modeling).
- NAAQS analysis (air dispersion modeling).
- Class I analysis (air dispersion modeling).

NNSR for $PM_{2.5}$

On May 8, 2008, the USEPA promulgated specific NSR rules for $PM_{2.5}$ emissions, and the effective date of these rules was July 15, 2008. It is B&V’s understanding that as of July 15, 2008, Indiana is no longer allowed to use PM_{10} as a surrogate for $PM_{2.5}$ in its NNSR program and construction permits in nonattainment areas will be issued pursuant to 40 CFR Part 51, Appendix S, until Indiana revises its SIP to incorporate the new NNSR regulations for $PM_{2.5}$. Furthermore, since July 15, 2008, SO_2 is being regulated as a $PM_{2.5}$ precursor in all nonattainment areas for $PM_{2.5}$ in Indiana, and NO_x is not being regulated as a $PM_{2.5}$ precursor until the Indiana SIP is revised.

The JMEU plant is a major stationary source under NNSR rules (326 IAC 2-1.1-5), since it has been determined by the IDEM that direct $PM_{2.5}$ and SO_2 (surrogate for $PM_{2.5}$) are emitted at a rate of 100 tpy or more. Since the JMEU plant is located in an area that is classified as nonattainment for $PM_{2.5}$, any physical change or change in the method of operation will be subject to the nonattainment major NSR requirements if the change results in an emission increase of $PM_{2.5}$ and/or its surrogates as regulated in Indiana, i.e., SO_2, in the amounts greater than 10 tpy and 40 tpy, respectively. Nonattainment major NSR requirements include requirements such as the installation of the lowest achievable emission rate (LAER) technology, procuring emission offsets, and conducting an analysis of alternate sites.

Emissions Change Calculation

In general, a project’s emissions increase can be determined in three different ways, depending on the type of project.

1. For projects that involve the addition of new emission units, the emissions change is determined by comparing the pre-project BAE with the post-project PTE. Since pre-project BAEs are zero for new units, their emissions change is equal to their PTEs. (Emissions change = PTE - BAE = PTE, note that in this case PAE = PTE).
2. For a project that involves modifying an existing unit, the post-project PAE instead of the PTE may be used in determining an existing unit’s emissions change from a modification to that unit. Note that at the Owner’s discretion, the PTE may still be used as the post-project emissions rate in doing the emissions change calculation if PAE cannot be determined. (Emissions change = PAE – BAE).

3. For a project that involves combinations of new emission units and existing emission units, the Hybrid Test is used. This involves using the appropriate emissions increase calculation methodology as described above for each type of emission unit and then summing the emissions changes to determine the total project emissions changes.

The emission changes determined using the above methodologies are compared to the appropriate PSD SER on a pollutant-by-pollutant basis. If the emissions increase is greater than the SER for a pollutant, then the project will be subject to PSD for that pollutant, unless netting, which is discussed below, demonstrates that the net emission increase for the entire facility is below the appropriate PSD SER.

Based on a review of past annual emission reports, the facility's actual reported annual emissions are significantly lower than the permitted PTE for NO_x, SO_2, particulates, CO, and VOCs listed in the facility's Title V permit technical support document (Table 4-2). In other words it is very likely that for the proposed life extension project the PTE – BAE (or PAE-BAE, if PAE can be estimated based on future load projections) will be greater than the SERs for all pollutants since on an annual basis the boiler will be utilized more that its utilization over the five immediately preceding years. Under such a situation, the JMEU plant would have to limit its future potential emissions to not exceed the BAE + SER for the regulated PSD and applicable NNSR pollutants to avoid PSD applicability and/or NNSR applicability for $PM_{2.5}$. It should be noted that in this emission change calculation, any emission increases attributed to natural demand growth can be excluded.

Table 4-2
Annual Emission Reported to IDEM vs. PTE (tpy)

Reporting Year	CO	NO_x	PM_{10}	SO_2	VOC	$PM_{2.5}$	Lead
2008	99.92	219.86	14.60	485.79	1.00	5.11	0.005
2007	90.22	198.48	44.25	821.71	1.26	38.16	0.005
2006	92.00	202.50	35.60	828.20	0.90	28.00	0.004
2005	38.80	85.40	44.30	304.00	0.40	33.20	0.002
2004	92.00	202.50	35.60	828.20	0.90	28.00	0.004
PTE	204.90	415.34	347.31	5046.16	4.01		

4.3.2 Netting

If a project's emission increases at existing major PSD sources are greater than the respective SER for a pollutant(s), what is referred to as a netting analysis can be conducted to try to avoid PSD permitting for the project. The netting analysis involves computing the net emissions change resulting from emissions increases and decreases that have occurred throughout the entire facility. This process involves evaluating all contemporaneous emission changes (increases and decreases in actual emissions) at the entire facility and determining if they are creditable. These contemporaneous, creditable emissions changes are summed with the project emission increases to determine the net emissions increase. If the analysis demonstrates that there will be a significant net emissions increase for a particular pollutant, the proposed project will be subject to PSD for that pollutant. Note that the project emissions increase and the net emissions increase both must be greater than the SER level for a pollutant for PSD to apply. Therefore, netting is only considered if the project emissions increase for a pollutant is greater than the SER for that pollutant. The contemporaneous period used in a PSD netting analysis begins on the date 5 years before construction commences on the proposed modification and ends on the date the emissions increase from the proposed modification occurs. Based on the information gathered during the site visit to the JMEU plant and review of the facility's Title V permit, it is very unlikely that netting can be used at the facility since there have been no documented creditable decreases that have occurred at the facility in the previous 5 years.

4.4 Biomass Co-Firing

Initiation of a biomass co-firing program will require the project to go through a permit evaluation process. If the co-firing program is going to be implemented for a short time for test burning only, and temporary structures will need to be built, then the IDEM can approve a permit exemption or issue a temporary permit. If the co-firing program is going to be implemented on a permanent basis and includes test burning, the entire project, including material handling will need to be evaluated from an overall emissions standpoint to determine if a significant increase in emissions is likely to occur. If that occurs, the project must go through a formal construction permit application process. The appropriate amount of time will need to be budgeted for either scenario. The details are provided below.

Irrespective of whether or not the co-firing program will be implemented on a temporary or permanent basis, B&V recommends that JMEU meet with IDEM early in the planning phase and present the project details, such as the quantities and quality of biomass to be burned, the duration of the test burn, and other matters the IDEM may deem relevant. Depending on the data provided, IDEM may agree to an exemption from obtaining an air construction permit for the initial test burn. If an exemption is granted, then approval timing would be approximately 2 weeks. If an air construction permit is required, it would likely be a test-burn permit and require 2 to 3 months to obtain. The test-burn permit must be obtained prior to the start of the trial burn. Test-burn permits are typically temporary permits/approvals that authorize the affected facility to conduct the necessary performance and emissions tests for data gathering purposes. Test-burn permits are usually valid for a period of 3 months, but can be extended upon request.

The trial burn will reveal how the boiler performs while co-firing alternate fuels, how the air pollution control equipment functions while co-firing, and how the material handling equipment is working. The concurrent stack tests can be used to estimate and then compare emissions of criteria pollutants. It should be noted that in addition to flue gas emissions, emission changes from material handling/blending will also need to be considered.

If a permanent biomass material handling and blending system is being planned and/or co-firing biomass is going to be implemented on a permanent basis, then an evaluation of the entire project emissions must be done. Information gathered during the trial burn can be used for this. The permit evaluation needs to consider emissions from the biomass material handling, conveying and storage systems, as well as any potential emission increases (or decreases) from the boiler operation, coal and ash handling systems as one single project. This air construction permit must be obtained prior to construction and an application to modify the Title V permit must be submitted to the IDEM within 12 months after initiating co-firing operations to incorporate the terms of the air construction permit into the Title V Permit. It is recommended that JMEU obtain IDEM approvals for both the trial-burn phase and the permanent phase of the project at the same time to reduce the overall impact to the project timing schedule.

4.5 Industrial Boiler Maximum Available Control Technology

The JMEU plant is an existing major source for hazardous air pollutants (HAPs). The boiler at the JMEU plant would have been classified as an affected source under the Industrial Boiler MACT *(NESHAP Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters)*, which was promulgated on September 13, 2004. The boiler, based on its heat input rating, type of fuel fired, and capacity factor, would have been considered an existing large solid fuel fired boiler under this MACT. On June 8, 2007, the United States Court of Appeals for the District of Columbia Circuit (DC Circuit) vacated the Boiler MACT in its entirety. Subsequently, this ruling was mandated by the Court on July 30, 2007, which means that there is currently no Industrial Boiler MACT standard in place.

After the Court's mandate on the Boiler MACT was issued on July 30, 2007, the USEPA advised permit authorities that another federal CAA requirement known as the Section 112(j) "MACT Hammer," codified in 42 U.S.C. 7412(j)(2), became effective. This CAA provision requires permitting authorities to issue case-by-case MACT determinations when the USEPA has failed to promulgate a MACT for an identified source category, which in this case is industrial boilers.

Under Section 112(j) requirements, an a*ffected source* is considered the "collection of equipment, activities, or both within a single contiguous area and under common control that is in a section 112(c) source category or subcategory for which the Administrator has failed to promulgate an emission standard by the section 112(j) deadline, and that is addressed by an applicable MACT emission limitation established pursuant to this subpart." The subpart being referenced to in this definition is 40 CFR Part 63 Subpart B *Requirements for the Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections, Sections 112(g) and 112(j)*. The requirements to conduct a case-by-case MACT determination under Section 112(j) are codified under 40 CFR Subpart B §§ 63.50 through 63.56. Because of the Boiler MACT's vacatur, the boiler will be subject to the requirements for existing sources as required by 40 CFR Part 63 Subpart B. However, the IDEM has indicated that they will follow the USEPA direction implementation of Section 112(j) and will not get ahead of the EPA. The IDEM has also conveyed that it recognizes that case-by-case determinations must be made, but it is not sure how that will be approached.

The Boiler MACT in its new form is due for proposal by early spring of 2010 and finalization by mid-2010. It is expected that the pollutants that were regulated in the previous version of the Boiler MACT will be regulated again. These include mercury and CO, particulate matter, HCl, which are surrogates for organic HAPs, metallic HAPs, and inorganic HAPs, respectively. Existing sources will be given 3 years from the date of the effective date of the new regulation to demonstrate compliance. It is expected that emissions limits will be significantly lower than the limits contained in the previous version of the Boiler MACT. The JMEU plant will need to investigate further, the technical and economic feasibility of installing add-on emissions controls for complying with future lower emission limits for HCl, mercury, and particulate matter. It should be noted here that if the life-extension projects are implemented, which trigger PSD/NNSR applicability, then it is possible that implementation of BACT/LAER type technologies to comply with the PSD/NNSR review requirements, could coincidentally result in MACT compliance also. If the plant continues to operate as is without any upgrades, Boiler MACT will still be applicable and will need to be complied with.

4.6 New Source Performance Standards

The JMEU plant is currently not subject to any New Source Performance Standards (NSPS) because it was constructed before 1971. However, any modification and/or reconstruction of existing emission units as defined under the NSPS, could potentially trigger NSPS applicability. The NSPS definition of reconstruction is found at 40 CFR 60.15. A change is considered reconstruction if the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new unit. It is assumed that the cost of adding co-firing of biomass does not exceed 50 percent of the cost to build a new unit, and as such, the projects do not constitute reconstruction under the NSPS definition.

The NSPS definition of modification is found at 40 CFR 60.2 and CFR 60.14. Under this definition, any physical or operational change that results in an increase in the emission rate to which a standard applies is considered a modification. For NSPS purposes, the emission rate is expressed in kilograms per hour (kg/h) of any pollutant discharged into the atmosphere for which a standard is applicable. Therefore, unlike the definition of modification in the current NSR/PSD regulations, the NSPS definition is based on hourly emissions rather than annual emissions. Further, the NSPS definition of modification specifically indicates that *no physical change, or change in the method of operation, at an existing electric utility steam generating unit shall be treated as a modification provided that such change does not increase the maximum emissions of any pollutant regulated under the NSPS above the maximum hourly emissions achievable at that unit during the 5 years prior to the change*.

4.6.1 NSPS Subpart Da

If the proposed life extension projects, including possible co-firing of biomass, if considered a modification or reconstruction under NSPS definitions, could subject the JMEU plant to NSPS Subpart Da for Electric Utility Steam Generating Units. NSPS Subpart Da is applicable to each electric utility steam generating unit for which construction or modification is commenced after September 18, 1978. Should a change to a facility be considered a modification under NSPS, it could impose new emission limits on the emissions of NO_x, SO_2, and PM_{10}. Applicability of NSPS Subpart Da will be confirmed after the preliminary emission estimates from the proposed project are developed.

4.6.2 Recently Revised NSPS Subpart Y for Coal Preparation Plants

On October 8, 2009, the EPA finalized the proposed revisions to emissions control requirements for new coal preparation and processing plants. The final rule is applicable to new coal preparation and processing plants that process more than 200 tons of coal per day. The final rule revises the particulate matter and opacity standards for thermal dryers, pneumatic coal cleaning equipment, and coal handling equipment located at coal preparation and processing plants. It also establishes work practice standards to control coal dust emissions from open storage piles and roadways associated with coal preparation and processing plants constructed after May 27, 2009.

The applicability of this rule will, therefore, need to be evaluated if the existing storage piles and/or coal material handling systems will be modified or reconstructed as defined under the NSPS regulations. If these operations will have an hourly increase in emissions, they are considered as modified as defined under the NSPS and will be subject to the requirements of the new rule which includes limits on opacity and grain outlet loading for dust collectors, and implementation of a fugitive dust control plan for the storage pile.

4.7 Summary and Recommendations

The JMEU plant may have to consider limiting its facility-wide emissions for regulated PSD and NNSR applicable pollutants to avoid PSD/NNSR applicability if plant life extension upgrades are implemented. If limiting the emissions is not economically feasible, then JMEU will have to subject the proposed project to major source NNSR/PSD review. The JMEU plant will be subject to the Boiler MACT requirements regardless of any upgrades after the revised rule is finalized (most probably in 2010) and will be required to demonstrate initial compliance within 3 years of the effective date of the final Boiler MACT Rule. The air permitting issues discussed above are manageable hurdles in the air permitting process if they are addressed early in the project development phase.

5.0 Performance

5.1 Performance Profile

The plant was originally operated as a baseload facility until 1993, at which time it began operating in a cycling mode to reduce the electrical system daytime peak demand loads during the weekdays. During this time, load was increased during peak hours to 13 to 14 MW and then reduced to 7 MW during off-peak hours. At the end of 2008, the market price for coal generated electric power decrease and coal prices increased, resulting in a discontinuance of operations. Currently, the plant only operates periodically as a facility providing emergency capacity to IMPA. As of October 2009, the JMEU facility had not been operated since July and had only operated on three separate occasions producing a total of 6,922 MWh for the year.

5.2 Output and Heat Rate

Based on the original plant guaranteed performance, the rated gross output of the plant was 14.5 MW, and the gross heat rate was 10,495 Btu/kWh at full load. The gross plant output and estimated gross heat rate for 2005 to 2009 are listed in Table 5-1. The heat rate is based on the gross plant generation, coal usage, and coal heating values provided by the plant.

Table 5-1
Historical Output and Heat Rate

	Gross Plant Output (kWh)	Estimated Gross Plant Heat Rate (Btu/kWh)(1)
2005	24,276,000	14,816(2)
2006	56,767,200	14,510(2)
2007	56,246,400	14,677
2008	60,883,200	15,976
2009	6,921,600	15,237

(1)Estimate based on monthly coal consumption and heating values provided by JMEU.
(2)Coal heating values were not available for these years. Used 11,500 Btu/lb as a default value.

The gross heat rate data shown in Table 5-1 is considerably higher (worse) than the rated design heat rate. There are multiple factors that can contribute to the degraded heat rate. The most significant reason contributing to the higher heat rate of the JMEU unit is the fact that the plant does not operate continuously at full load. Because of this, the efficiency of the boiler and the turbine are lower than expected. There appeared to be a substantial increase in the plant heat rate from 2007 to 2008. Without additional operating data and information about the plant, B&V cannot determine the noteworthy increase.

5.3 Expected Performance

If the plant continues to be operated periodically, or as a facility providing emergency capacity only, it is expected that it will continue to perform as it has historically. If the plant is operated as a baseload unit at full capacity, the efficiency of the unit should improve resulting in a lower heat rate as long as operations and maintenance personnel continue utilizing established processes and practices. Life extension upgrades to the boiler and steam turbine, as recommended in Section 3.0, should also improve the efficiency of the unit and result in a lower plant heat rate.

5.4 Generation Availability Data

Reliability data such as equivalent availability factor (EAF) and equivalent forced outage rate (EFOR) for the JMEU plant were not available during the site visit.

5.5 Industry Comparisons

Reliability data such as EAF and EFOR for the JMEU plant were not available during the site visit and should be provided if possible. A comparison of reliability data of the JMEU facility to industry data is not possible at this time. Table 5-2 lists industry availability and reliability data for stoker boiler units. The data are based on a study completed by B&V in 1998. Table 5-2 is provided for reference only.

Table 5-2
Availability and Reliability of Stoker Boiler Units

Net Capacity Factor(1)	75.6%
Service Factor(2)	93.3%
Equivalent Availability Factor(3)	93.0%
Equivalent Forced Outage Rate(4)	4.7%

(1)Net Capacity Factor is the net actual plant generation divided by the net maximum plant generation for a given period.
(2)Service Factor is plant service hours divided by the period hours.
(3)Equivalent Availability Factor is the available plant generation divided by the maximum plant generation.
(4)Equivalent Forced Outage Rate is forced outage hours and equivalent derated hours divided by service hours, forced outage hours, and equivalent reserve shutdown forced derated hours.

6.0 Operations and Maintenance

During the site visit, B&V talked to plant personnel and reviewed the turbine generator, boiler, ESP, and ash handling system startup and shutdown procedures. The procedure for placing the generator on line was also reviewed. Daily logs that contain records of parameters during plant operation were checked to ensure the unit was operating as expected. Routine maintenance activities and records of plant equipment maintenance were reviewed.

6.1 Staffing and Organization

The JMEU facility is staffed to provide O&M support for 24 hours per day and 7 days per week with 14 full-time employees, excluding the General Manager. The station organizational chart is illustrated on Figure 6-1. During any period when less than the full complement of equipment operators is required or when the plant is not operating, the operations personnel will supplement maintenance needs by performing routine maintenance and any additional maintenance activities that the specific operator is qualified to perform.

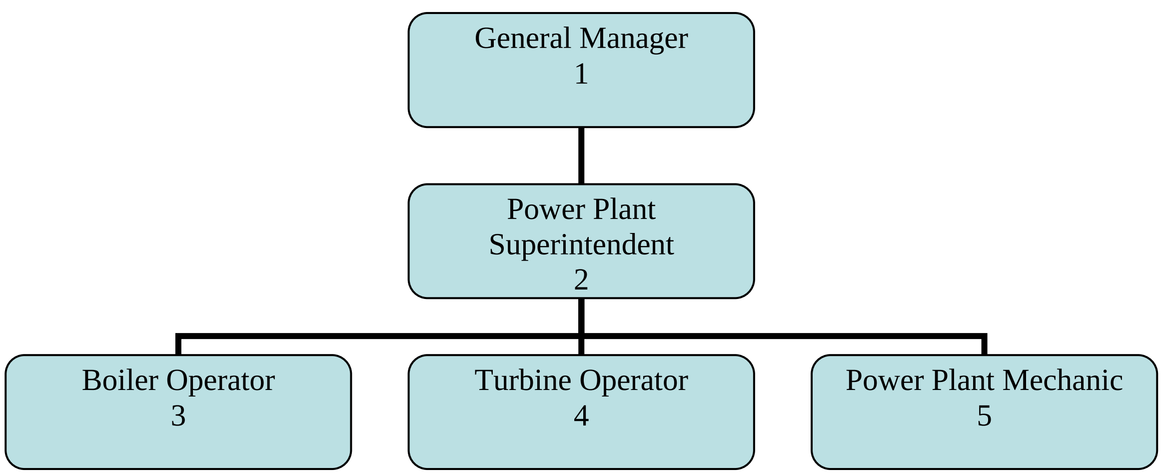


Figure 6-1
JMEU Organizational Chart

6.2 Maintenance Program

The JMEU staff is responsible for routine maintenance activities and the condition-based maintenance program. The program is based on making sound technical and business decisions based on the condition assessment of the equipment. This can provide good reliability at a lower cost due to better optimization of funds and resources. Based on the low number of hours that the plant currently operates, this type of maintenance program appears to be adequate.

The facility equipment maintenance records were reviewed. It was noted that recent maintenance had been performed, but the records were not kept up to date.

Based on observations made during the plant walkdown, the equipment appears to be maintained properly and in good condition.

6.3 Historical O&M Costs

Historical O&M costs for the facility were provided by JMEU and are shown in Table 6-1.

Table 6-1
JMEU Historical O&M Costs

	Nonfuel O&M Cost ($)	Fuel Cost ($)	Total O&M Cost ($)	Total kWh Produced	Cost per kWh ($/kWh)
2007	818,038	2,018,689	2,836,727	50,008,000	0.0567
2008	679,219	2,479,228	3,158,446	55107000	0.0573
2009	382,536	272,992	655,528	5794000	0.113

6.4 O&M Cost Forecast

Based on historical O&M costs and the projected performance and operating profile (refer to Section 11.0), an O&M cost forecast was developed by B&V is are shown in Table 6-2.

Table 6-2
JMEU 20 Year Projected O&M Costs

Year	Non-fuel O&M Cost ($)	CoalCost ($)	Total O&M Cost ($)
2010	657,440	651,365	1,308,806
2011	678,906	868,487	1,547,393
2012	682,648	416,150	1,098,798
2013	699,487	411,394	1,110,881
2014	783,810	3,435,734	4,219,545
2015	817,815	4,050,685	4,868,500
2016	839,574	4,209,536	5,049,110
2017	856,350	4,179,573	5,035,922
2018	880,840	4,394,544	5,275,384
2019	909,431	4,794,048	5,703,479
2020	931,261	4,815,926	5,747,186
2021	951,778	4,931,972	5,883,750
2022	972,808	4,989,995	5,962,804
2023	994,364	5,135,053	6,129,418
2024	1,016,460	5,164,065	6,180,524
2025	1,039,107	5,164,065	6,203,172
2026	1,062,321	5,222,088	6,284,409
2027	1,086,115	5,193,076	6,279,191
2028	1,110,503	5,251,100	6,361,603
2029	1,135,502	5,251,100	6,386,601

7.0 Biomass Co-Firing Opportunity

7.1 Introduction

The purpose of this section is to provide a high level analysis to determine the technical viability of co-firing biomass in the existing coal spreader stoker boiler at the JMEU plant and to provide an order of magnitude capital cost required to implement the biomass material handling to feed the biomass fuel into the existing boiler. The analysis will be based on the identified quantities and type (composition) of biomass fuel available at the JMEU plant provided by Bingham McHale (see Appendix B).

Co-firing is the simultaneous combustion of different fuels in the same boiler. Co-firing inexpensive biomass with fossil fuels in existing boilers provides an opportunity to use a greenhouse gas-neutral renewable fuel while reducing energy and waste disposal costs.

Specific requirements will depend on the site. But in general, co-firing biomass in an existing coal fired boiler involves modifying or adding to the fuel handling, storage, and feed systems. Fuel sources and the type of boiler at the site will dictate fuel processing requirements.

7.2 Fuel Supply

Bingham McHale has identified the biomass fuel quantities and type available in the vicinity of the plant. The summary of their findings is included in Appendix B.

The biomass fuel identified is wood dust available from several furniture manufacturing facilities in the Jasper area and in surrounding cities. The quantities available are approximately 1,500 tons per month, and the chemical composition of the fuel is similar to a fuel ultimate analysis provided from Kimball 1998. The heat content of the wood dust is 7,500 Btu/lb, and the cost delivered to the site is $20/ton.

With these quantities of biomass fuel available, it is assumed that 20 percent co-firing can be at achieved at the present boiler rated capacity.

7.3 Considerations When Co-firing Biomass Fuel

Stoker boilers with chain or traveling grates like the one at the JMEU plant tend to be both robust in design and forgiving in their ability to burn fuels with varying characteristics. Stoker boilers are, thus, best suited for co-firing and can readily absorb changes in fuel characteristics without large changes in performance and operation. Stoker boilers have been shown to co-fire up to 20 to 25 percent wood fuel on a weight basis without significant detrimental effects.

Wood fuels and coal are very different. Industrial coal fired boilers are typically designed to burn specific types of coal with a limited range of fuel characteristics. An issue with co-firing wood fuels with coal is the effect of the wood on the overall fuel characteristics. The change in fuel characteristics resulting from co-firing can significantly affect boiler performance and operation, and ash generated by the combustion of wood fuel is likely to be different than that generated by coal. The differences may include a reduction in the ash softening, fusion temperature, and the likelihood that ash will collect on boiler tubes and other surfaces. Ash deposition reduces heat transfer to the boiler tubes negatively impacting boiler efficiency and fuel use. In extreme cases, ash deposition results in slagging in which relatively large and often dangerous pieces of fused ash flow or drop off boiler tubes. For instance, boiler height and residence time in some older stoker units may not be sufficient to achieve burnout of wood fuel particles that burn in suspension. However, it is the overall opinion of the industry that as long as the co-fire rate is kept below 20 to 25 percent on a weight basis, ash deposition or slagging should not be a problem.

In regard to air emissions, it is believed that the concern about air emissions from coal fired industrial boilers could stimulate interest in co-firing because it will result in the reduction of both SO_x and CO_2.

7.3.1 Technology Options for Co-Firing Biomass in Spreader Stoker Boilers

There are several options for co-firing biomass in a stoker boiler similar to the boiler in the JMEU plant. Some of the options considered at the JMEU plant were:

- Pelletize the biomass fuel to blend it with stoker coal and feed the mixture to the boiler through the existing feeder and spreader. This option although highly preferred is not justifiable because of the high cost of the biomass pelletizing preparation.
- Provide a separate feeder in parallel to the coal feeder using the existing or a modified spreader. This system allows good versatility to use a variety of biomass fuels as long the fuel can be handled by the material handling system and the boiler can be adjusted to maintain nearly the same operating efficiency. Unfortunately this system requires expensive modifications, and it is better suited for larger boilers than the one at JMEU.
- Provide a separate pneumatic conveying system to handle the biomass fuel, and inject it into the boiler through ports above the grate by the spreaders. This system requires minimum modifications to the boiler and is the least expensive to implement. For this reason, it was selected for further consideration.

7.3.2 Cost to Implement Biomass Feedstock Preparation and Pneumatic Feeding System

The biomass feedstock preparation and handling facilities contemplated for 20 percent co-firing would be required to handle 2.83 tons per hour (tph) of biomass at boiler rated capacity and would consist of the following major elements:

- Biomass fuel unloading building with associated conveyors for fuel screening, milling, and metal separation.
- Two storage silos to provide onsite storage for 2 days with vertical loading and unloading elevators.
- Pneumatic or belt conveying system to biomass metering bin.
- Biomass dust injection system, metering variable speed screw feeders, rotary seal feeders, and HP fan and dust injection nozzles. This feeder system is illustrated in Figure 7-1 provided by the Detroit Stoker Company.

The order of magnitude cost for this system installed is approximately $1.5 million.

7.4 Conclusions Regarding Biomass Firing Viability

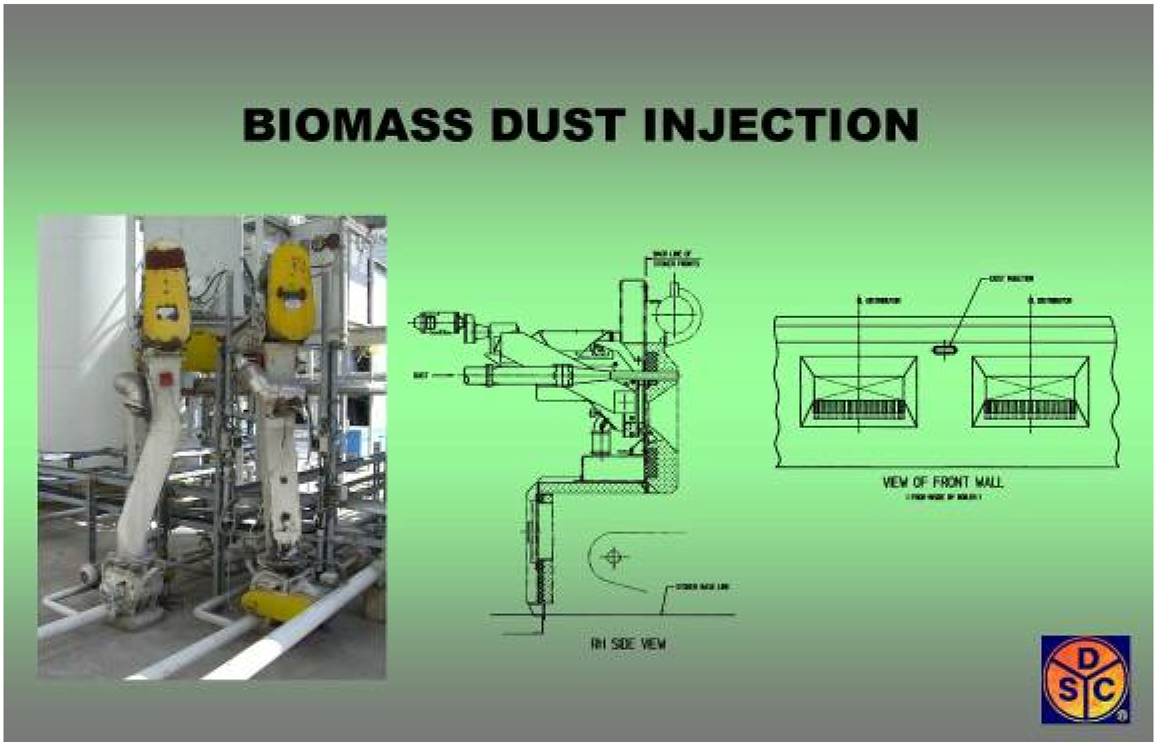
7.4.1 Environmental Permitting

Permit modifications may be required because requirements vary from site to site. An environmental permitting assessment should be carried out during the next phase if co-firing is further considered. This subject is covered in greater detail in Section 4.4.

Some potential benefits regarding emissions can be expected from co-firing with biomass because it will result in the reduction of both SO_x and CO_2.

Similar to SO_x, lead and mercury emissions are dependent on the amount of the metal that enters the boiler as fuel. Since wood contains only trace amounts of lead and mercury, co-firing should reduce the emission of the two metals by an amount proportional to the co-firing rate.

The emission of NO_x is different, since NO_x is formed during the combustion process from nitrogen contained in both fuel and combustion air. Co-firing wood fuels is believed to have NO_x benefits in many coal fired boilers because of wood fuel's lower flame temperature than that of coal. However, flame temperature is only one of many factors that can affect NO_x formation, and in some situations co-firing may result in an NO_x increase. However, the NO_x decreases are described as "trimming" and are not necessarily enough to achieve NO_x reductions required by potential future air regulations.



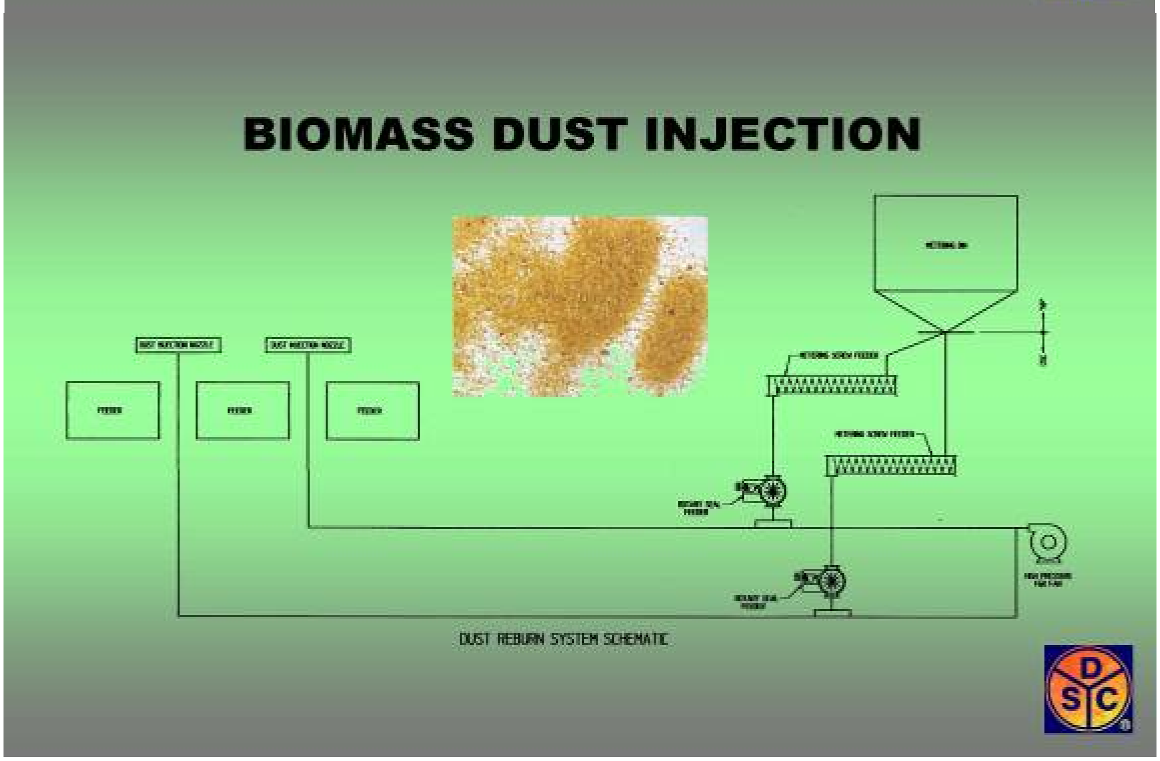


Figure 7-1
Biomass Co-Firing

7.4.2 Economics

Project economics largely determine whether a co-firing project can successfully be implemented.

In order to provide a high level analysis of the cost savings for co-firing, it has been assumed from historical operational data for the last five years as shown in Table 7-1, that operation of the plant requires approximately 40,000 tpy. The cost from Bingham McHale for the identified wood residue biomass delivered to the JMEU plant is $20/ton.

Table 7-1
Jasper Municipal Electric Utility Coal Used in Generating (2004-2009)

Year	Coal Used (including delivery charge)				Ash Disposal Cost $
	Pounds	Tons	$ Amount	Avg. Cost per ton $	
2004	73,627,089	36,813.54	1,194,113.31	32.44	38,561.59
2005	31,276,620	15,638.31	662,051.31	42.34	16,440.58
2006	71,626,682	35,813.34	2,025,747.16	56.56	38,029.15
2007	72,225,510	36,112.75	2,018,688.61	55.90	45,726.68
2008	80,104,240	40,052.12	2,479,227.50	61.90	67,261.78
2009	8,885,920	4,442.96	272,992.12	61.44	5,015.48

Based on the information in Table 7-1, the cost savings strictly from fuel cost, assuming coal with 11,200 Btu/lb and a delivered price of $70/ton and wood biomass with 7,500 Btu/lb and a delivered price of $20/ton, the net fuel savings per year is:

40,000 tpy x 20% = 8,000 tpy of coal to be replaced with wood biomass provides

Fuel cost savings per year =

$$\left(8{,}000\ \mathrm{t} \times \$70/\mathrm{t} - \frac{11{,}200\ \mathrm{Btu/lb}}{7{,}500\ \mathrm{Btu/lb}} \times 8{,}000\ \mathrm{t} \times \$20/\mathrm{t}\right) = \$321{,}000$$

The fuel cost savings per year plus any other incentive applicable to the use of biomass identified by Bingham McHale should make co-firing an attractive opportunity that should be analyzed in greater detail in the next phase of this project.

8.0 Full Biomass Conversion

8.1 Introduction

Biomass is organic material of recent origin, and is one of the most diverse sources of energy. This section provides an overview of biomass energy policy, a discussion of biomass fuel considerations, and an order of magnitude cost for a full conversion to biomass for the JMEU plant.

8.2 Biomass Energy Statistics

Biomass has been used as an energy source for more than 1 million years. Today, about 14 percent of the world's primary energy comes from biomass, according to the International Energy Agency. According to the US DOE Energy Information Administration[2], biomass has been the largest source of renewable energy in the United States since 2000 as shown on Figures 8-1 and 8-2. Out of a total renewable use of 6.8 quadrillion Btu ("quads"), biomass accounted for 3.6 quads, or about 53 percent. The next largest renewable source is hydro, which comprises about 36 percent of the total. Other renewables, including geothermal, wind, and solar, comprise much smaller shares (5.1, 5.0, and 1.2 percent, respectively). Note: This data includes all forms of energy consumption (electricity, heat, transportation, etc.).

Overall, the consumption of biomass for energy has remained relatively constant over the past 15 years. The industrial sector uses the largest amount of biomass, about 2.0 quads in 2004 (the latest year for which data is available). About one quarter of this is used for power generation, while the remainder of the biomass is burned for process heat. The power sector (utility and IPP) consumed 0.4 quads in 2007, which is almost double the amount consumed in 1989, the first year of data reported by the Energy Information Administration (EIA). On the other hand, residential and commercial consumption of biomass has declined from 1.02 quads in 1989 to 0.53 quad in 2007. Transportation fuels (e.g., ethanol) are still a relatively small portion of total biomass use. However, over the past 4 years, their use has more than doubled, from 0.30 quad in 2004 to 0.63 quad in 2007. Due to legislative support for biofuels, it is expected that this upward trend will continue through the remainder of this decade.

[2] US DOE EIA, "Renewable Energy Annual, 2007 Edition," May 2009, available at: http://www.eia.doe.gov/cneaf/solar.renewables/page/rea_data/rea_sum.html. All statistics presented in this section are based on the latest EIA data.

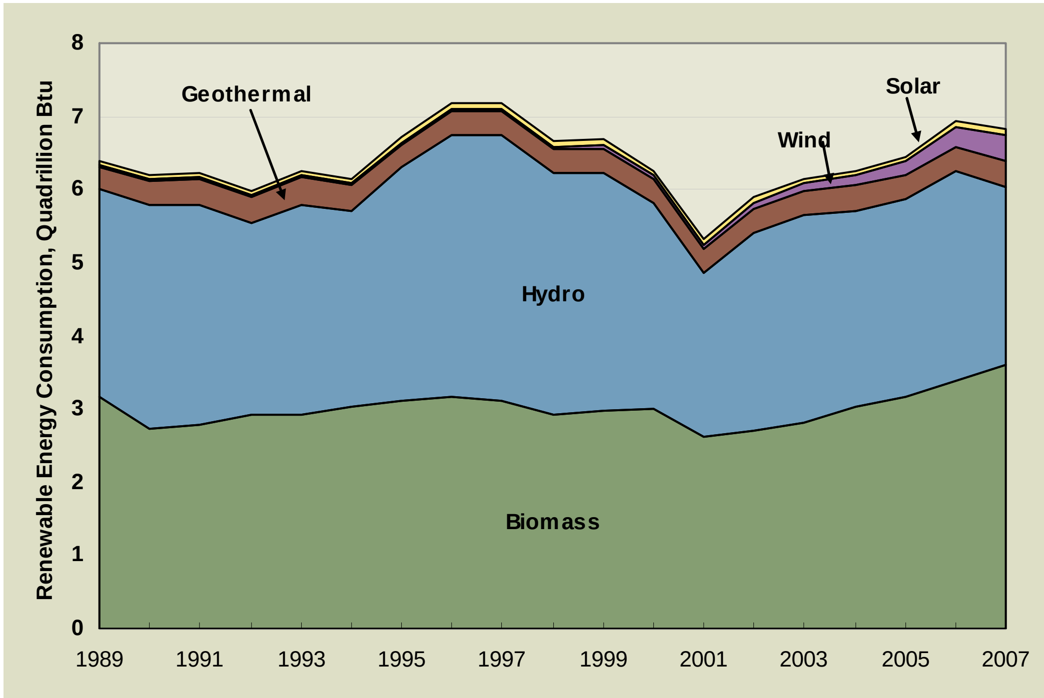


Figure 8-1
US Renewable Energy Consumption (Source: EIA)

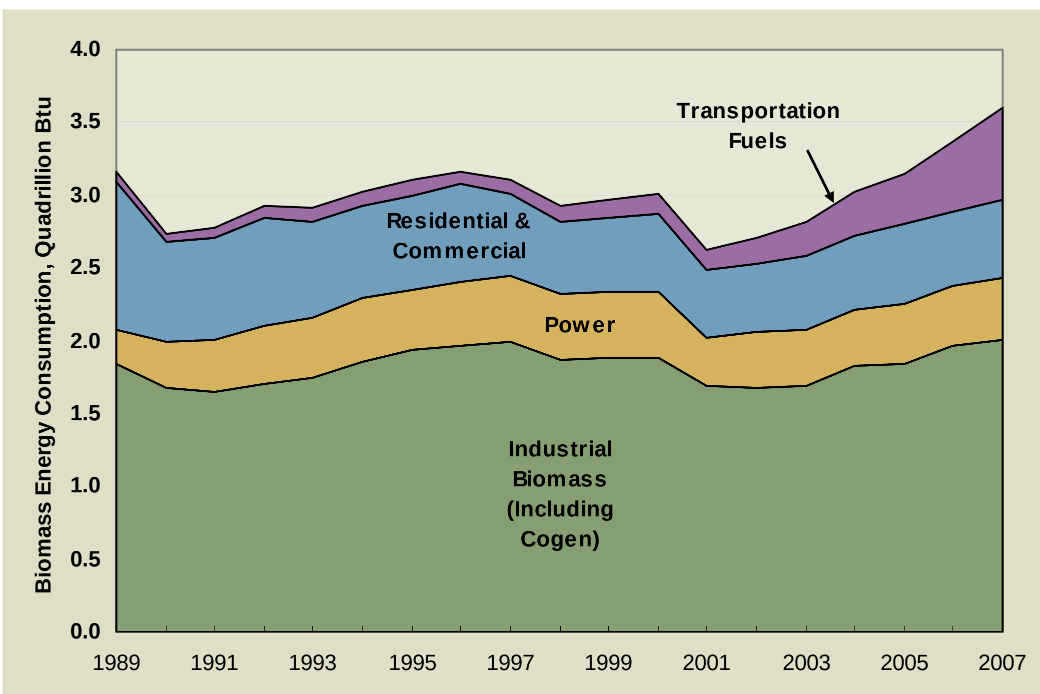
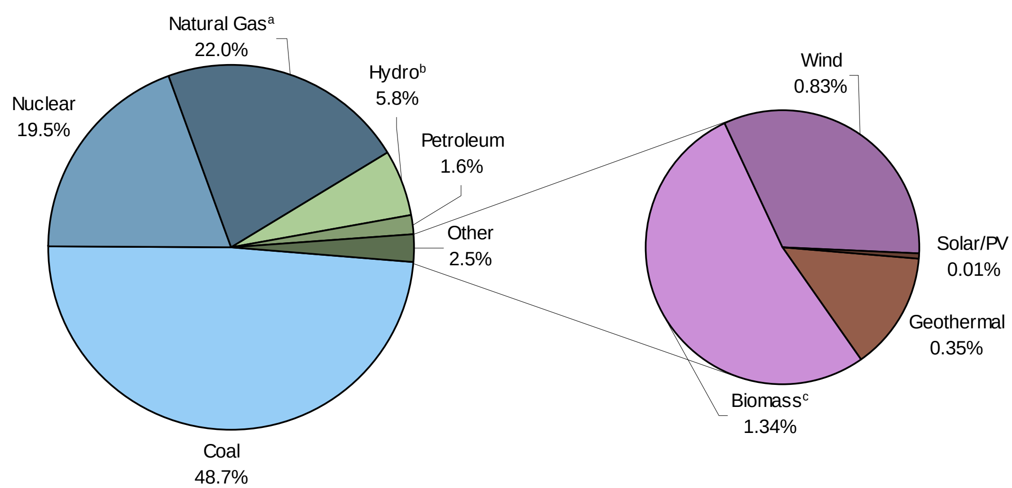


Figure 8-2
US Biomass Energy Consumption by Sector (Source: EIA)

Biomass (including landfill gas and waste-to-energy facilities) provides nearly 11 GW (billion watts) of power to the electricity grid and is the largest non-hydroelectric renewable source of electricity. Even still, biomass makes a very minor contribution to the nation's overall power supply, only 1.3 percent of 2007 generation, as shown on Figure 8-3. Biomass power is derived from four broad categories: wood and wood waste, municipal solid waste (MSW), landfill gas, and agricultural waste and other sources. The largest source of biomass is wood and wood waste (6.7 GW in 2007). A large fraction of this is derived from black liquor recovery boilers in the pulp and paper industry. Waste to energy plants burning MSW provide about 2.2 GW, followed by landfill gas recovery facilities, which generate about 1.3 GW. Agricultural waste and other sources of biomass are responsible for about 0.6 GW of capacity.



[a] Includes small amount of other gases (propane, refinery, etc.)
[b] Includes pumped storage hydro
[c] Includes w ood, w aste-to-energy, landfill gas, agricultural by-products, etc.

Figure 8-3
US Electricity Generation by Source, 2007 (Source: EIA)

Until very recently, growth of new biomass power generation capacity has stagnated. Biomass is generally more expensive than conventional fossil fuels on a \$/mmBtu basis because of added transportation costs. However, rising fossil fuel prices and recent policy changes have stimulated new interest in biomass, as discussed further in the next section.

8.3 Biomass Policies and Incentives

Currently, new biomass energy developments are driven primarily by state renewable portfolio standards (RPS) and federal tax policies. In addition, rising fossil fuel prices and concerns about greenhouse gases have also contributed to development recently. RPS programs mandate that utilities procure a certain percentage of their power from renewable sources. RPS goals vary greatly by region and by state, as does the specific consideration for biomass energy.

Twenty-nine states and the District of Columbia currently have mandatory RPSs requirements, as shown on Figure 8-4. Another five states have non-binding renewable generation goals. State RPS programs alone are expected to drive nearly 350,000 GWh of new non-hydro generation by 2030, with a potential of roughly 450,000 GWh if all targets are met. Indiana does not currently have a statewide RPS program. However, efforts are underway to establish an RPS program in the state. This subject is covered in detail by Bingham McHale (Appendix B).

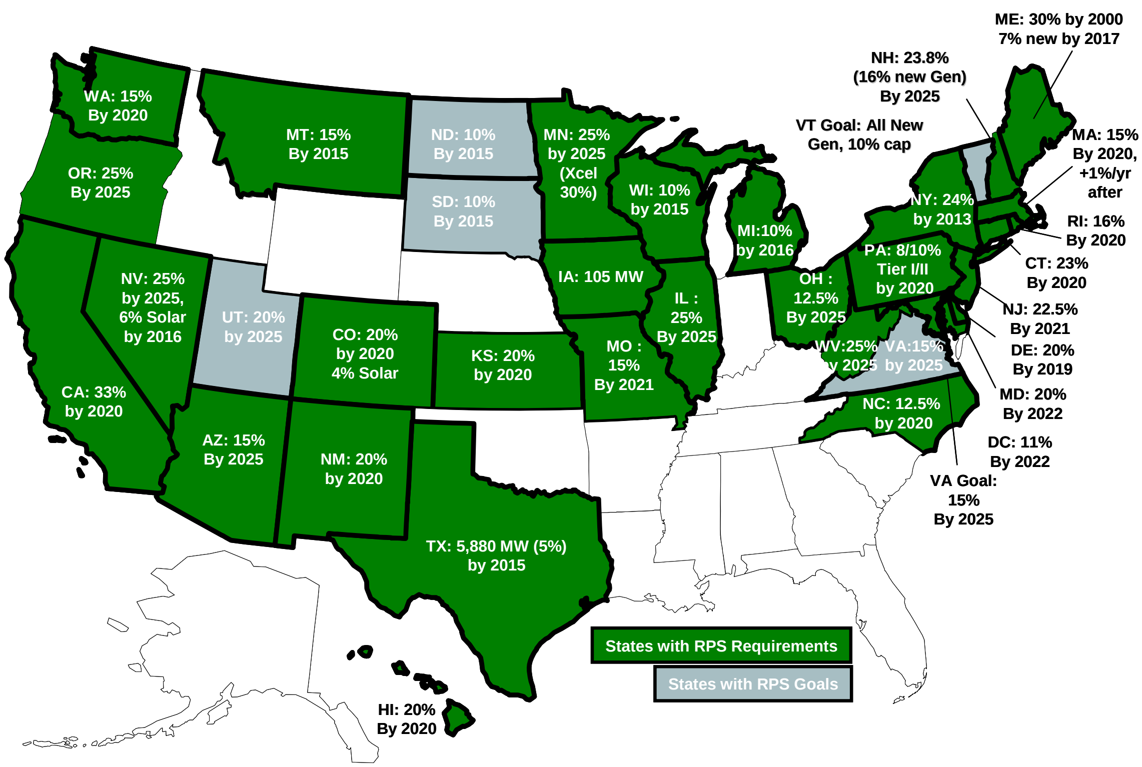


Figure 8-4
States with Renewable Portfolio Standards (as of November 2009)

The net economic effect of RPS policies is to increase the demand for renewable energy in the region, resulting in a premium value for renewable power over conventional resources. Prices for renewable energy credits, which capture the premium value of renewable energy, range from over $50/MWh in Massachusetts to under $10/MWh in New Jersey.[3] The prices vary dramatically based on the specific requirements of individual state policies, the type of resource, and local supply and demand issues. Each RPS provides different restrictions and/or requirements for biomass energy. For example, co-firing may not qualify to meet RPS requirements in every state, and treated wood is typically not eligible.

In addition to state policies, the federal government offers production tax credits, accelerated depreciation, production incentives, low interest loans, and other incentives for qualifying biomass projects. These incentives serve to reduce the cost of biomass power. The potential incentives applicable to the JMEU plant are covered in detail by Bingham McHale (Appendix B).

8.4 Biomass Feedstock Considerations

Wood and wood residue (including black liquor) is the most common biomass fuel. Other biomass fuels include agricultural residues, dried manure and sewage sludge, and dedicated fuel crops such as switchgrass and coppiced willow. Ethanol co-products, including distillers wet grain cake and syrup, are also increasingly being considered as potential biomass fuels. MSW is another biomass fuel option, and there are many municipal waste burners installed throughout the world employing similar conversion technology. However, the construction of new MSW combustion plants has become difficult in the United States because of environmental concerns regarding toxic air emissions.

This section provides an overview of general biomass fuel qualities, discusses common biomass fuel concerns, and reviews the fuels studied for this project.

8.4.1 General Biomass Fuel Characteristics

Compared to coal, biomass fuels are generally less dense, have lower energy content, and are more difficult to handle. With some exceptions, these qualities generally mean that biomass fuel is disadvantaged economically compared to fossil fuels. Positive and negative aspects of biomass fuels relative to coal are listed in Table 8-1.

[3] E. Holt and L. Bird, "Emerging Markets for Renewable Energy Certificates: Opportunities and Challenges," National Renewable Energy Laboratory, 2005.

Table 8-1
Biomass Compared to Coal

Biomass Negatives	Biomass Positives
Lower Heating Value	Lower Sulfur, Heavy Metals, and Other Pollutants
Lower Density	Potentially Lower and More Stable Cost
More Variability	Generally Low Ash Content
More Difficult to Handle	Renewable Energy
Can Be High in Moisture Content	“Green” Image
More Geographically Disperse	Incentives May Be Available
Limited Fuel Market	Reduced Greenhouse Gas Emissions
Potential for Elevated Alkali Content	Local Economic Development Benefits

Environmental benefits can help make biomass an economically competitive fuel. Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation option. While carbon dioxide is emitted during biomass combustion, an equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Thus, biomass fuels “recycle” atmospheric carbon, minimizing its global warming impact. Further, biomass fuels contain little sulfur compared to coal and, therefore, produce less SO_2. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead. On the other hand, facilities that fire biomass or biomass-derived syngas still must cope with some of the same pollution issues as larger coal fired plants. Primary pollutants are NO_x, particulate matter, and CO. Standard air quality control technologies are used to manage these pollutants.

Environmental issues also affect biomass resource collection. Several states impose specific criteria on biomass resources for them to be classified as renewable energy sources. A key concern is sustainability of the feedstock. Projects relying on forestry or agricultural products must be careful to ensure that fuel harvesting and collection practices are sustainable and provide a net benefit to the environment. Many biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space. Targeting certain wastes for power production (such as animal manure) can also address other emerging environmental problems.

The capacity of biomass plants is usually less than 50 MW because of the dispersed nature of the feedstock and the large quantities of fuel required. Furthermore, biomass plants commonly have lower efficiencies than modern coal plants. The efficiency is lower because of the smaller scale of the plants and the higher moisture content of the biomass fuel compared to coal. Additionally, biomass is typically more expensive and lower in density than coal. These factors usually limit use of biomass technologies to inexpensive or waste biomass sources.

Prices for biomass fuels vary widely depending on the source. Some fuels are considered wastes and may be available for power generation at no cost. In some cases, accepting biomass as a fuel may result in a small revenue stream for the facility (for MSW burners, tipping fees are the primary revenue source). On the other hand, premiums may be paid for fuels from dedicated energy crops, or when fuel markets are tight. Unlike fossil fuels, historically, it has not been economical to transport biomass fuels over long distances (greater than 100 miles). This is due to their low energy density and high moisture content. However, in Europe high fossil fuel prices and the value of CO_2 have led to the import of biomass from very distant locations, including sources in the United States and other foreign countries.

8.4.2 Biomass Fuel Types

Forest product residues (including wood and black liquor) are the most common biomass fuel. Other biomass fuels include agricultural residues, dried manure, sewage sludge, and dedicated fuel crops such as switchgrass and coppiced willow. These are further described below:

- Wood--Wood for biomass fuel can be derived from a very wide variety of sources, including primary wood industries (such as sawmills), secondary wood industries (such as furniture manufacturers), forest harvest residues, urban landscape trimmings, urban solid waste collection, and construction and demolition debris. These wastes are available as sawdust, chips, bark, chunks, dimensional lumber, and other forms. Moisture content typically ranges from 10 to 20 percent for "dry" wood to over 50 percent for green wood. Fuel sizing is frequently required, as is some amount of screening to remove foreign debris. Clean wood is generally low in alkali minerals; slagging and fouling are less likely with wood than with other biomass fuel types. A wide variety of wood residues are available in Indiana and are potentially available to the JMEU plant.
- Crop Residue--Crops such as corn, cotton stalks, fruit trees, and those with shells or hulls can provide a fuel resource. Corn stover is the remainder of the plant after harvest, including the stalk, leaves, and sometimes cob. Trimming and periodic replacement of fruit trees produce large quantities of woody waste. Oats, rice, peanuts, and other crops can provide a consistent stream of hulls/shells at the processing mills, substantially reducing collection costs. Crop residues are generally higher in alkali

minerals and care must be taken when mixing these with coal when considering co-firing. While there are considerable agricultural residues in Indiana, quantities are limited compared to wood residues, and their use requires particular consideration to the selection of the equipment and materials for a full biomass conversion.

- Manure--Stricter environmental regulations are causing farmers to consider alternative methods for manure disposal. Manure from poultry and bovine sources, including feedlot cattle, turkey farms, and dairy cows, can be a viable fuel. Poultry litter contains a large percentage of wood shavings or other bedding material. Some bovine wastes are too wet for combustion, but others are naturally drier due to farming methods. Swine manure is nearly always too wet to be considered for combustion. Chlorine may also be a significant concern in manure (HCl formation in products of combustion). In particular, the use of turkey litter at the JMEU plant is not recommended because of potential strong odors, the negative reaction from the community, and the opposition of environmental advocates who question the earth friendliness of the operation. The JMEU plant is just too close to a living community to consider any manure operation.
- Sewage Sludge--Sludge from municipal wastewater plants can be a viable fuel, especially if it has been thermally dried. Thermal drying can yield a pathogen-free fuel (“biosolids”) with a higher heating value of 9,500 Btu/lb, 5 percent moisture, and 1.5 percent sulfur. Dried material is typically available in pellet form.

Wood, primarily consisting of urban wood waste and furniture manufacturing wood residues, has been identified as the likely fuel for this project. A complete assessment of the available biomass fuel supply near the JMEU plant will be required to be conducted, and the typical properties of this fuel supply identified for specific consideration of a full biomass facility.

8.5 Biomass Fuel Concerns

There are numerous technical concerns with biomass fuels that can affect plant design and operation including alkali, moisture, and chlorine.

The ash from biomass fuels can have high levels of alkali components. The alkali components of ash, particularly potassium and sodium compounds such as potassium oxide (K_2O) and sodium oxide (Na_2O), cause the ash to remain sticky at a much lower temperature than coal ash. This increased stickiness creates the potential for serious slagging and fouling problems. In fluidized bed technologies, high alkali content can also lead to bed agglomeration. Figure 8-5 shows boiler slagging caused by combustion of urban tree trimmings, a relatively low-alkali fuel. To remove the sticky material from the boiler or gasification reactor surfaces, it is required to perform soot blowing, implement operational procedures such as slag shedding, or have regularly scheduled outages to manually clean the unit. While none of these factors are critical flaws with regard to technical feasibility, they do present significant maintenance and availability burdens that need to be accounted for. These concerns can be substantially reduced if the potential for alkali deposition is properly considered during boiler/gasifier design.

The problems associated with alkali materials in biomass vary widely between different biomass fuels. To a certain extent, slagging potential can be determined by the analysis of fuel properties. However, the slagging tendency of a particular fuel cannot be predicted from fuel properties alone. Boiler design and operating conditions (especially temperature) have a large impact on the nature of deposits. Gasification of high alkali fuels and subsequent combustion of the gas in the boiler may reduce ash deposition. The success of this approach depends on maintaining gasification temperatures below combustion temperatures. Temperatures of 1,400 °F and below have been shown to significantly reduce deposition.[4]

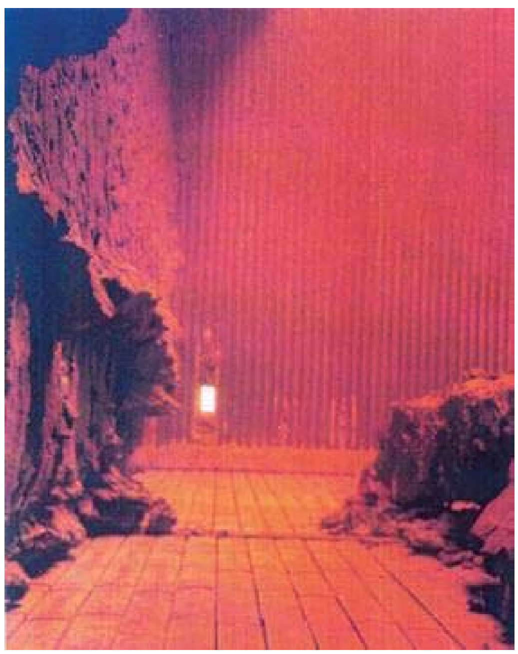


Figure 8-5
Biomass Boiler Slagging After Operating for 4 Days on Urban Tree Trimmings
(Source: T.R. Miles)

[4] Thomas R. Miles, et al, "Alkali Deposits Found in Biomass Power Plants," April 15, 1995.

One alternative that can be considered, particularly for fluidized bed conversion technologies, is the addition of limestone or other additives (such as magnesium oxide) to the fuel feed. The limestone works to reduce the concentration of the alkali material, affecting the bulk fusion temperatures, and it inhibits the stickiness of the ash.

Common biomass fuels with the highest alkali contents are typically nut hulls, crop residues (such as rice and grain straws), grasses, and animal manure. The hulls of rice and grains typically have much lower alkali content than straw. Therefore, if a unit only burns hulls, some of the design parameters applied to biomass fuels with much higher alkali material contents may be relaxed.

High moisture content in biomass can reduce efficiency of combustion processes and may necessitate the need for supplemental fuel. Herbaceous biomass is composed primarily of cellulose, hemicellulose, and water. The heating value of a biomass fuel is inversely proportional to its moisture content. The higher the moisture content, the lower the heating value. In addition, boiler efficiency is negatively impacted by high moisture fuels. Fuel that is too wet, may not burn. Biomass with a moisture content of up to 65 percent by weight can be burned in some combustion technologies while maintaining stable combustion without the use of a supplemental fuel. If the moisture content is higher than 65 percent, the fuel can still be burned provided supplemental fuel is burned or some other process is used to recover exhaust heat for air or fuel preheating.

8.6 Opinion of Cost for Full Biomass Plants

The assumptions for costing purposes are based on the use of green wood for biomass fuel with 50 percent moisture content with approximately 4,500 Btu/lb heat content on wet basis. Also, it has been assumed that the existing boiler cannot be reused because of its present design, and the required derating would not allow the 15 MW power production. However, the balance of plant except for the flue gas system will be reused. A new 69 kV transmission line and a new 20 MVA substation have been included to allow delivering the total plant output directly to MISO.

Installed costs can vary significantly depending on the scope of the equipment included, output steam conditions, geographical area, competitive market conditions, site requirements, emission control requirements, and prevailing labor rates. Two of the most proven technologies have been chosen for the estimates, these are: stoker boiler technology and fluidized bed boiler technology.

The estimates presented in Table 8-2 are budgetary estimates based on published data and discussions with equipment suppliers and developers and from our database. The range of expected cost variations can be as high as ±40 percent depending on the site and system variables listed above.

Table 8-2
Order of Magnitude Cost for 100 Percent Biomass Plants[1,2]

Biomass Requirements	**Approximately 600 Tons/Day**
Biomass Heat Input (mmBtu/h)	297.5
Steam Pressure (psig)	675
Stoker Boiler Technology	
Steam Output (lb/h)	165,000
Stoker Boiler Equipment Cost	$10,374,000
Other Equipment and Installation	$13,026,000
Total Installed Boiler System Cost	$23,400,000
Total Installed Biomass Prep-Yard	$7,590,000
Electrical Substation and Transmission Line and Miscellaneous	$5,000,000
Miscellaneous Upgrades to Existing Steam Turbine Generator	$3,000,000
Total Installed Stoker Boiler Steam Plant Cost	**$38,990,000**
Fluidized Bed Boiler Technology	
Steam Output (lb/h)	175,000
Fluidized Bed Boiler Equipment and Installation Cost	$18,837,000
Other Equipment and Installation	$13,026,000
Total Installed Boiler System Cost	$31,363,000
Total Installed Biomass Prep-Yard	$7,059,000
Electrical Substation and Transmission Line and Miscellaneous	$5,000,000
Miscellaneous Upgrades to Existing Steam Turbine Generator	$3,000,000
Total Installed Fluidized Bed Boiler Steam Plant Cost	**$46,422,000**

(1)Price does not include a new steam turbine generator. It is assumed the existing steam turbine and generator will be reused. Price for air quality control equipment for environmental compliance is not included.
(2)Estimates have a ±40 percent accuracy.

9.0 Combined Heat and Power Opportunity

9.1 Introduction

The purpose of this section is to provide a high level analysis to determine the technical and financial viability of converting the JMEU plant into a CHP plant and to provide an order of magnitude capital cost required to implement the steam system modifications and a new steam distribution system to the potential users. The analysis will be based on yearly quantities of steam to users identified by the City of Jasper as requiring significant amounts of steam year-around for heating and/or process, to determine if it would be financially viable.

CHP is defined as the sequential or simultaneous generation of multiple forms of useful energy in a single, integrated system. A CHP consists of a number of individual components, such as the prime mover (heat engine), generator, heat recovery, and electrical interconnection all integrated into a single system. The prime mover typically identifies the type of CHP system. In the case of the JMEU plant, and as depicted in Figure 9-1, the prime mover is the steam turbine driving the generator, and steam at lower pressure is extracted from the steam turbine to provide steam to potential users near the plant.

9.2 Potential Steam Users

The City has identified two potential steam users that have year-around steam usage and are located within 1-1/2 miles of the JMEU plant. The selected users are Memorial Hospital & Health Care at 800 West 9th Street and Jasper Rubber Company near Truman Road and 1st Street. The City provided monthly boiler gas usage and annual gas cost for each user.

The Memorial Hospital & Health Care site visit confirmed year-around steam generation with a Johnston 700 bhp, a Johnston 400 bhp, and a Cleaver Brooks 250 bhp boilers. Boilers are sequenced to operate large boiler during winter with small boilers for backup, and sequence small boilers during spring, summer, and fall. Based on annual operation data, the estimated winter steam demand is 14,000 lb/h, summer steam demand is 4,000 lb/h, and annual steam usage is about 49,777,733 pounds per year. The estimated gas fired boiler cost is $13.25/mmBtu without O&M cost.

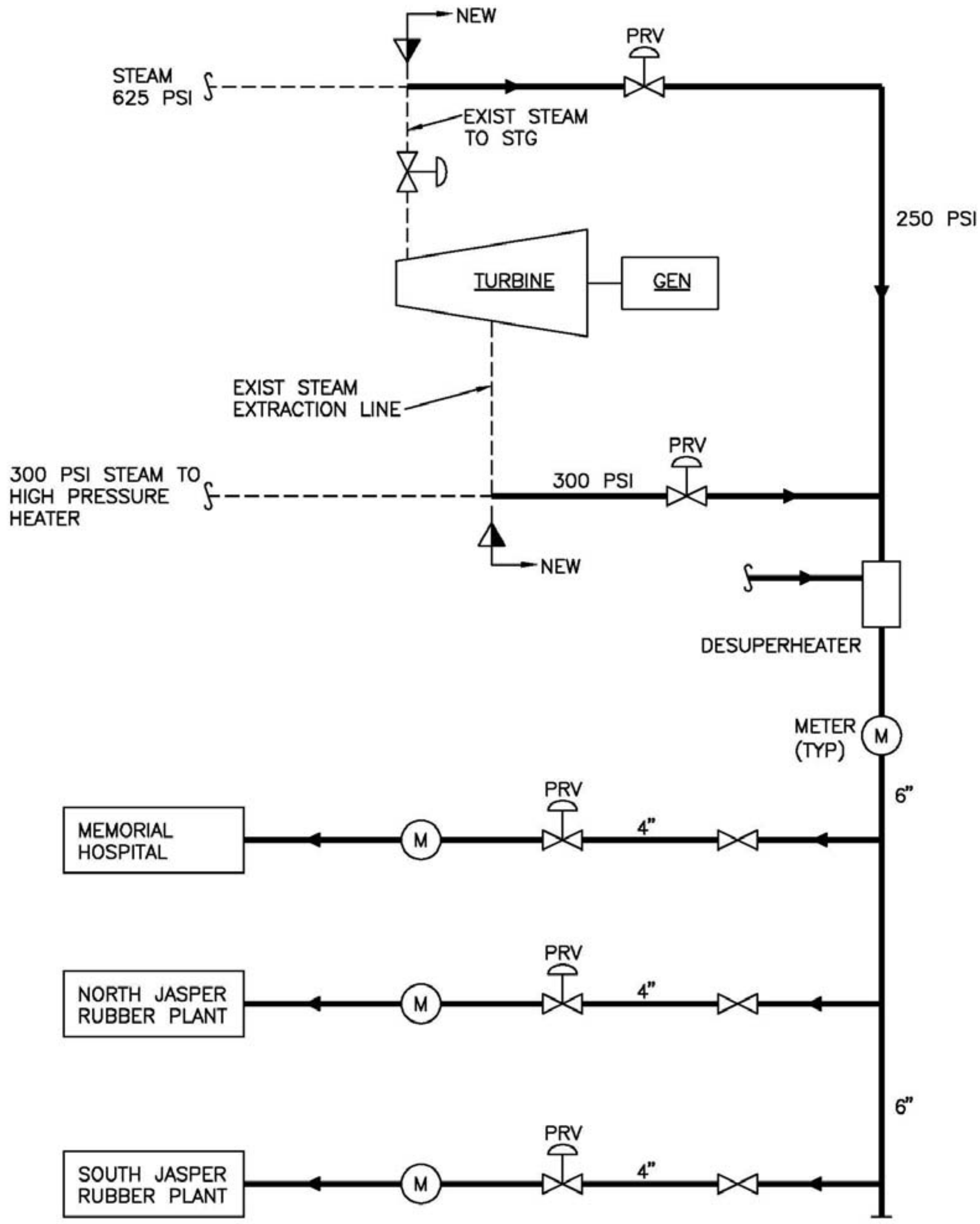


Figure 9-1
CHP Process Flow

The Jasper Rubber Company site visit confirmed year-around steam generation with a Kewanee 350 bhp, a Kewanee 200 bhp, and a Donlee 350 bhp boiler. Boilers are operated to maintain process steam header pressure at each plant. Based on annual operation data, the estimated maximum steam generation is 19,000 lb/h, minimum steam 4,000 lb/h, and annual steam usage is about 32,320,367 pounds per year. Based on $9.00/mmBtu natural gas cost to the user and boiler efficiency at 75 percent, the estimated gas fired boiler cost is $13.25/mmBtu without O&M cost.

9.3 Order of Magnitude Cost to Implement CHP

A CHP conversion at the JMEU plant as indicated on Figure 9-1, will consist of extraction steam (16,000 lb/h at 300 psig), a 600 psig high-pressure steam reduced to 250 psig with a pressure reducing station, desuperheater, and plant flow meter connected to the steam distribution system to users. A 6 inch insulated steam distribution line has been assumed to handle all the steam requirements for the two identified users and will be routed approximately 7,000 feet, to each user's facility steam header. Each user will have a steam metering station with pressure reducing valves to maintain user system distribution pressure. In accordance with a service agreement with user, the user will maintain its existing boilers operational for backup for an emergency or scheduled outage at the JMEU plant.

The construction budget estimate for the converting JMEU to CHP to serve the two users described above is estimated at about $4,000,000.

9.4 Conclusions Regarding CHP Viability

Project economics will determine whether a CHP project is a viable option for implementation.

JMEU plant extraction steam, as illustrated on Figure 9-1, has a 16,000 lb/h rating and an estimated 2010 energy cost to users of $0.80/mmBtu without O&M cost for steam distribution, the City capital recovery, or profit.

The user steam maximum demand of 30,000 lb/h exceeds the steam turbine extraction capacity; therefore, the 600 psig supply from the boiler must be used to makeup the difference to handle users' operating loads. The 2010 energy cost of the 600 psig steam reduced to 250 psig is estimated at a net cost of $5.47/mmBtu without cost for steam distribution, the City capital recovery, or profit.

Based on annual operation of the JMEU CHP and annual net sales of about 82,098,000 pounds per year at 90 percent availability, the extraction steam would provide about 60 percent of the annual requirement and the boiler 600 psig would supply the remaining 40 percent. The estimated annual steam energy cost is calculated as ($0.80/mmBtu x 60% + $5.47/mmBtu x 40%) = $2.67/mmBtu.

The JMEU CHP would provide O&M for the steam distribution, control of steam supply from JMEU to user's, and metering of users steam as illustrated on Figure 9-1. The CHP O&M cost is estimated at $20,000 per year or about $0.50/mmBtu.

The steam cost delivered to the users is estimated at an energy cost of $2.67/mmBtu and distribution cost of $0.50/mmBtu or $3.17/mmBtu.

In summary, if the JMEU plant is converted to CHP, the following factors will be present:

- JMEU availability must be 90 percent or more to reduce operating hours of the user's boilers when CHP is out of service.
- JMEU steam turbine HP extraction is limited to about 16,000 lb/h and cannot handle all the users' loads without pressure reducing the 625 psi steam to 250 psi steam. The CHP steam cost in excess of 16,000 lb/h is estimated at additional ($5.47-$0.80) = $4.67/mmBtu.

The high level financial analysis is based on the following:

- It is assumed that CHP steam can be sold to users for about $10.60/mmBtu. This price is about 20 percent less of the users' cost to produce steam without O&M.
- JMEU CHP sales at $10.60/mmBtu would provide a gross profit of $7.43/mmBtu or (82,098,000 pounds per year x 1,000 Btu/lb/1,000,000 Btu x $7.43/mmBtu) ~ $610,000.00 per year.
- The capital cost of JMEU to provide steam to the remote users is about $4,000,000.00, and the $18,277.00 gross profit will provide a simple payback in 6.5 years. However, this gross profit might have to be reduced considerably after the City subtracts the decreased revenue from selling natural gas to the users.

In conclusion, B&V does not recommend the implementation of a CHP to the JMEU plant.

10.0 Base Case Description

10.1 Description

The JMEU plant is located on East 15th Street within the city limits of Jasper, Indiana. The facility was put into service in 1968 and consists of a Riley Coal Stoker boiler and a General Electric non-reheat steam turbine with an air-cooled generator. The boiler is rated for 140,000 lb/h steam at 625 psig and 825° F. Natural gas fuel is used as the fuel source during unit startup. The steam turbine has a rated pressure of 600 psig and 825° F, and the generator produces 13,200 volts with a design peak output of 14.5 MW, entering the distribution system at one of several substations. Minimum stable load for the unit is approximately 5 MW.

The JMEU Figure 10-1 plant site shows an aerial picture of power plant with ESP, coal handling, ash handling, and coal storage on the east side of plant. The area south of the power plant to the utility storage area was reserved for future plant expansion. The cooling tower and maintenance building are located southeast of power plant.

Figure 10-1
Plant Site

10.2 Base Case Plant Operation

The base case plant operation will maintain plant operational with condition-based maintenance the next 5 years or more without major upgrades or improvements as listed in Section 3.0. During the next 5 years, some of these items are condition-based maintenance items that must be completed to maintain plant operational.

Historical base case indicates the plant used 35,000 to 40,000 tpy of coal with a plant annual capacity factor of 39 to 43 percent and an annual net heat rate of approximately 16,400 Btu/kWh.

10.3 Life Extension Upgrades Impact on Base Case

The life extension upgrades will improve plant performance by more than 2 percent, reduce plant annual maintenance costs, and provide better plant management of controls and records.

The upgrades will provide controls to monitor, control boiler performance, steam turbine generator performance, and plant emission control monitoring. Additional controls may be required to meet future boiler MACT requirements.

The control upgrades will be designed to integrate boiler co-firing with biomass or natural gas or future re-powering plant.

The new plant transmission line to grid interface will be designed for 70 MW; therefore, the plant could be expanded in the future.

11.0 Plant Valuation

11.1 Introduction

B&V prepared a market valuation of the JMEU plant for the following three cases: market value "as-is," market value with life extension improvements, and salvage value. For the market value "as-is," both a cost based and income based valuation were considered. The market value with life extension improvements is an income based valuation with three sales forecast scenarios: base case, high energy prices (High Energy Market) and high fuel costs (High Fuel Market). The salvage value considers both the scrap value of the plant as well as the used equipment market. Table 11-1 provides the results of the market valuation cases.

Table 11-1
Market Valuation Summary

Market Valuation Case	JMEU Plant Value (2010 dollars)
Valuation "As-Is"	
Cost Based "As-Is"	$6,743,000
Income Based "As-Is"	($4,544,000)
Valuation with Life Extension Improvements	
Base Case	($12,115,000)
High Energy Market	($1,513,000)
High Fuel Market	($19,807,000)
Salvage Value	
Scrap Value	$375,000
Used Equipment Value	N/A

11.2 Market Value "As-Is"

B&V determined the market value the JMEU plant "as-is" based on two traditional measures: cost based and income based. B&V uses the trended original cost less depreciation (TOCLD) method to determine its cost based value and the discounted cash flow (DCF) method to determine its income based value. B&V finds the cost based value of the JMEU plant to be $6.7 million before any adjustment for functional obsolescence, and the income based value to be negative $4.5 million. One measure of functional obsolescence is the difference between the income based and cost based measures (-$4.5 million - $6.7 million = -$11.2 million).

11.2.1 Cost Based "As-Is" Value

Trended original cost (TOC) is defined as the estimated cost today of constructing a system identical to that being valued. B&V adjusts the original installed cost of the facilities as recorded on the books and records to reflect changes in cost and productivity levels which have occurred between the time the facilities were originally constructed and today. Changes in cost and productivity levels are recognized through the use of trend factors.

B&V has determined TOC for each Federal Energy Regulatory Commission (FERC) plant account by vintage year (year of original installation) by applying the approximate trend factor to the surviving original cost (original cost new) for that vintage. The trend factor for each vintage is calculated as the current Handy Whitman Index (July 1, 2009, North Central Region), for the specific account divided by the July 1 index for that vintage. The results of calculations are summarized in Table 11-2. As shown in Column G of Table 11-2, the TOC of the JMEU plant as of December 31, 2008, is $27,983,605.

The value, or TOCLD, is calculated by multiplying the trended original cost by an appropriate condition percent factor for that vintage and account. For the JMEU plant, B&V determined the condition percent based on an estimated 5 year remaining life. However, we do not use a condition percent of less than 20 percent. A 5 year remaining life is estimated based on the age of the assets and the conclusions from our onsite inspections. B&V estimated 20 year remaining life if the life is extended. The "as-is" value of the JMEU plant with life extension is considered to be the TOCLD with a 20 year remaining life less the capital expenditure required to achieve the life extension. The calculation of TOCLD is also summarized in Table 11-1. As shown in Column K of Table 11-2, TOCLD of the JMEU plant as of December 31, 2008 is $6,742,976 assuming a 5 year remaining life, and $4,913,238 assuming a 20 year remaining life, reduced for capital improvements. Neither of these amounts have been adjusted for functional obsolescence.

Table 11-2
Trended Original Cost Less Depreciation

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
		Installation Date							Condition Percent		TOCLD	
Line No.	Description	Date	Year	OCN @ 12/31/08	HW Index @ Installation	Current HW Index	TOC	Age	No Life Extension	w/ Life Extension	No Life Extension	w/ Life Extension
				$				Yr.	$	$	$	$
Account 311												
1	New Plant Structures	01/01/67	1967	1,576,393	62.00	490.00	12,582,899	43.00	20.00%	49.40%	2,516,580	6,215,912
2	Quanset Hut - Steel Warehouse Building	01/01/67	1967	18,491	62.00	490.00	147,595	43.00	20.00%	49.40%	29,519	72,911
3	Quanset Hut - Steel Warehouse Building Sub-structure	01/01/67	1967	2,904	62.00	490.00	23,176	43.00	20.00%	49.40%	4,635	11,449
4	New Plant Foundation Sub-Structure	01/01/67	1967	107,655	62.00	490.00	859,311	43.00	20.00%	49.40%	171,862	424,497
5	Maintenance Building Structure	01/01/67	1967	28,106	62.00	490.00	224,346	43.00	20.00%	49.40%	44,869	110,826
6	Maintenance Building Foundation Substructure	10/16/70	1970	3,092	76.00	490.00	20,132	39.21	20.00%	50.73%	4,026	10,213
7	Concrete Driveway - 49 x 25 x 6" Thick, 23 Yards Slick Finish	11/09/88	1988	1,265	252.00	490.00	2,484	21.14	24.42%	61.09%	607	1,518
8	Sidewalk 70" - Broomed Finish	11/09/88	1988	462	252.00	490.00	907	21.14	24.42%	61.09%	222	554
9	2/8 - M70 Steel Door on Steel Warehouse Building	12/14/89	1989	131	260.00	490.00	250	20.05	25.18%	62.06%	63	155
10	10' x 9' Steel Storage Building	06/24/91	1991	300	254.00	490.00	584	18.52	26.36%	63.50%	154	371
11	12 x 14' Overhead Door	08/06/93	1993	1,219	270.00	490.00	2,234	16.40	28.29%	65.72%	632	1,468
12	Stack Refurbish Lining and Paint	01/01/95	1995	72,950	297.00	490.00	121,556	15.00	29.80%	67.36%	36,230	81,877
13	Coal Bunker Construction	01/01/95	1995	167,260	297.00	490.00	278,704	15.00	29.80%	67.36%	83,067	187,727
14	Coal Pile and Sludge Basin Clean-up Earth / Disposal Work	01/01/95	1995	21,567	297.00	490.00	35,937	15.00	29.80%	67.36%	10,711	24,206
15	Stack Refurbish Engineering Services	01/01/95	1995	4,721	297.00	490.00	7,867	15.00	29.80%	67.36%	2,345	5,299
16	Coal Pile and Sludge Basin Cleanup Engineering Services	01/01/95	1995	64,587	297.00	490.00	107,622	15.00	29.80%	67.36%	32,076	72,491
17	Installed Versigard Roof	03/26/99	1999	7,879	329.00	490.00	11,852	10.77	36.01%	73.23%	4,268	8,679
18	Door on Wall of Turbine Room	05/30/02	2002	978	364.00	490.00	1,330	7.59	43.47%	78.89%	578	1,049
19				2,079,960	100.90	490.00	14,428,786	41.88	20.39%	0.50	2,942,444	7,231,203
Account 312												
20	Cooling Tower at Power Plant	01/01/67	1967	468,772	71.00	577.00	3,847,610	43.00	20.00%	49.40%	769,522	1,900,707
21	Cooling Tower Refurbish	01/01/95	1995	97,857	369.00	577.00	154,544	15.00	29.80%	67.36%	46,062	104,097
22	Multiclone System Material and Installation	01/01/95	1995	195,785	369.00	577.00	309,201	15.00	29.80%	67.36%	92,157	208,269
23	Coal Handling System Refurbish	01/01/95	1995	36,445	369.00	577.00	57,558	15.00	29.80%	67.36%	17,155	38,769
24	Superheater and Economizer Replacement	01/01/95	1995	348,225	369.00	577.00	549,947	15.00	29.80%	67.36%	163,911	370,429
25	Light Off Gas Burner Material and Installation	01/01/95	1995	360,120	369.00	577.00	568,734	15.00	29.80%	67.36%	169,510	383,083
26	Electrostatic Precipitator Material and Installation	01/01/95	1995	1,812,790	369.00	577.00	2,862,917	15.00	29.80%	67.36%	853,287	1,928,381
27	Boiler Controls - Replace Controls with Electronics	01/01/95	1995	181,929	369.00	577.00	287,319	15.00	29.80%	67.36%	85,635	193,530
28	Boiler Piping - Replace Blowdown Piping	01/01/95	1995	15,975	369.00	577.00	25,229	15.00	29.80%	67.36%	7,519	16,994
29	Boiler Cleaning - Acid Cleaning and Disposal	01/01/95	1995	69,680	369.00	577.00	110,045	15.00	29.80%	67.36%	32,799	74,123
30	Ash System Replacement	01/01/95	1995	493,293	369.00	577.00	779,052	15.00	29.80%	67.36%	232,195	524,747
31	Engineering: Field Assistance / Project Coordination	01/01/95	1995	273,339	369.00	577.00	431,682	15.00	29.80%	67.36%	128,662	290,769
32	Accounting / Legal / Permits / Administrative	01/01/95	1995	45,197	369.00	577.00	71,380	15.00	29.80%	67.36%	21,275	48,079
33	Capitalized Interest	01/01/95	1995	320,206	369.00	577.00	505,697	15.00	29.80%	67.36%	150,722	340,623
34	Multiclone System Engineering Services	01/01/95	1995	72,653	369.00	577.00	114,740	15.00	29.80%	67.36%	34,198	77,286
35	Coal Handling System Engineering Services	01/01/95	1995	2,361	369.00	577.00	3,729	15.00	29.80%	67.36%	1,111	2,512
36	Superheater and Economizer Engineering Services	01/01/95	1995	2,677	369.00	577.00	4,228	15.00	29.80%	67.36%	1,260	2,848
37	Light Off Gas Burner Engineering Services	01/01/95	1995	38,894	369.00	577.00	61,425	15.00	29.80%	67.36%	18,308	41,374
38	Electrostatic Precipitator Engineering Services	01/01/95	1995	76,017	369.00	577.00	120,053	15.00	29.80%	67.36%	35,782	80,864
39	Boiler Controls Engineering Services	01/01/95	1995	53,349	369.00	577.00	84,254	15.00	29.80%	67.36%	25,112	56,751
40	Boiler Piping Engineering Services	01/01/95	1995	5,917	369.00	577.00	9,345	15.00	29.80%	67.36%	2,785	6,294
41	Boiler Cleaning Engineering Services	01/01/95	1995	4,497	369.00	577.00	7,102	15.00	29.80%	67.36%	2,117	4,784
42	Ash System Replacement Engineering Services	01/01/95	1995	58,966	369.00	577.00	93,124	15.00	29.80%	67.36%	27,755	62,725
43				5,034,946	341.26	577.00	11,058,914	24.74	26.39%	0.61	2,918,837	6,758,039
Account 314												
44	Turbine and Exciter	01/01/95	1995	582,194	343.00	489.00	838,290	15.00	29.80%	67.36%	249,851	564,649
45	Turbine - Engineering Services	01/01/95	1995	38,559	343.00	489.00	55,520	15.00	29.80%	67.36%	16,548	37,397
46	Generator Rebuild & Upgrade	08/17/01	2001	689,862	394.00	489.00	864,742	8.37	41.30%	77.37%	357,131	669,060
47				1,310,615	369.84	489.00	1,758,552	11.74	35.46%	0.72	623,530	1,271,106
Account 315												
48	Chart Recorder 10" Strip 3-Channel	05/31/94	1994	4,538	351.00	793.00	10,355	15.59	29.15%	66.66%	3,018	6,902
49	House Transformer Purchases and Installation	01/01/95	1995	48,040	368.00	793.00	104,554	15.00	29.80%	67.36%	31,162	70,425
50	New House Transformer Engineering Study	01/01/95	1995	3,091	368.00	793.00	6,727	15.00	29.80%	67.36%	2,005	4,531
51				55,669	366.61	793.00	121,636	15.05	29.75%	0.67	36,185	81,858

Table 11-2 (Continued)
Trended Original Cost Less Depreciation

	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]	[J]	[K]	[L]
		Installation Date							Condition Percent		TOCLD	
Line No.	Description	Date	Year	OCN @ 12/31/08	HW Index @ Installation	Current HW Index	TOC	Age	No Life Extension	w/ Life Extension	No Life Extension	w/ Life Extension
Account 316												
52	Opacity Monitor Installation Engineering Services	05/03/91	1991	1,186	319.00	587.00	2,204	18.66	26.25%	63.36%	578	1,397
53	Opacity Monitor Installation Engineering Services	06/04/91	1991	2,350	319.00	587.00	4,367	18.58	26.32%	63.45%	1,149	2,771
54	Opacity Monitor Installation Engineering Services	07/03/91	1991	2,162	319.00	587.00	4,017	18.50	26.38%	63.53%	1,060	2,552
55	Continuous Emission Monitor Material and Installation	01/01/95	1995	102,325	366.00	587.00	165,750	15.00	29.80%	67.36%	49,401	111,644
56	Asbestos Removal and Reinsulate	01/01/95	1995	35,517	366.00	587.00	57,531	15.00	29.80%	67.36%	17,147	38,752
57	Emission Stack Tests to Determine Compliance	01/01/95	1995	14,215	366.00	587.00	23,026	15.00	29.80%	67.36%	6,863	15,510
58	Control Room Enclosure - Construction	01/01/95	1995	23,580	366.00	587.00	38,196	15.00	29.80%	67.36%	11,384	25,727
59	Cogen Engineering Rate Study	01/01/95	1995	1,590	366.00	587.00	2,575	15.00	29.80%	67.36%	767	1,734
60	Continuous Emission Monitor Engineering Services	01/01/95	1995	21,015	366.00	587.00	34,041	15.00	29.80%	67.36%	10,146	22,929
61	Asbestos Removal and Insulation Engineering Services	01/01/95	1995	13,192	366.00	587.00	21,369	15.00	29.80%	67.36%	6,369	14,393
62	Emission Stack Tests Engineering Services	01/01/95	1995	5,238	366.00	587.00	8,485	15.00	29.80%	67.36%	2,529	5,715
63	Oxygen Analyzer Teledyne Continuous Model 9500 S/N 147517	02/06/95	1995	4,973	366.00	587.00	8,056	14.90	29.92%	67.48%	2,410	5,436
64	Tuff Pressure Washer Model 830360 S/N 8522	09/18/95	1995	2,380	366.00	587.00	3,855	14.29	30.66%	68.24%	1,182	2,631
65	Amana Heat / Cool Model (Control Room)	08/03/99	1999	785	404.00	587.00	1,152	10.41	36.70%	73.80%	423	850
66	Boiler Computer with Conductor NT Server Software	09/03/02	2002	33,438	452.00	587.00	43,858	7.33	44.26%	79.42%	19,412	34,832
67				263,946	375.99	587.00	418,482	14.26	31.26%	0.69	130,821	286,873
68	Total Accounts 311, 312, 314, 315, and 316			8,745,135	289.58	544.80	27,786,369	32.62	23.94%	0.56	6,651,818	15,629,079
Account 310												
69	Beginning Balance - Plant Land	01/01/88	1988	22,306	100.00	100.00	22,528		100.00%	100.00%	22,528	22,528
General Plant Accounts												
70	Beginning Balance - New Radio Shack (Structure)	01/01/85	1985	3,815	134.49	243.25	6,969	25.00	22.20%	58.10%	1,547	4,049
71	Asphalt Paving around Shop, Cooling Tower and Precipitator	07/22/06	2006	67,700	225.89	243.25	73,633	3.44	61.71%	88.68%	45,440	65,297
72	Beginning Balance - Laboratory Equipment	01/01/67	1967	9,850	86.23	243.25	28,065	43.00	20.00%	49.40%	5,613	13,864
73	Refrigerator Sanyo Almond-Color (Shop) Model SR1120-2	12/03/84	1984	350	131.21	243.25	655	25.07	22.16%	58.04%	145	380
74	Beginning Balance - Communication Equipment	01/01/80	1980	16,630	118.87	243.25	34,372	30.00	20.07%	54.97%	6,900	18,893
75	ASP Antenna with 140 ft. 1/2 In. Heliax / 2 Connectors Model 685	12/04/87	1987	898	141.30	243.25	1,561	22.07	23.82%	60.31%	372	941
76	Mobile Midland CTCSS Base / Programming / Testing Model 70-385 (foı	04/20/88	1988	1,040	144.83	243.25	1,764	21.70	24.06%	60.63%	424	1,070
77	Phone System Power Plant / DM 16-Key BusinessCom	03/23/93	1993	2,442	163.86	243.25	3,661	16.78	27.93%	65.31%	1,022	2,391
78	Base / Adaptor DC-Tone Interface / Power Supply Cabinet Model 70-134I	04/03/97	1997	1,689	180.87	243.25	2,294	12.75	32.74%	70.28%	751	1,612
79	Hot Water Heater - Main Floor Model KTA-030-RR S/N ZJ3560115	12/15/84	1984	131	131.21	243.25	245	25.04	22.18%	58.07%	54	142
80	Split System Heatpump with 20 KW Resistance - Manager's Office 36,00	08/29/88	1988	3,062	144.83	243.25	5,194	21.34	24.29%	60.93%	1,262	3,165
81	Hilti Gun Kit	04/03/90	1990	1,711	152.16	243.25	2,762	19.75	25.40%	62.33%	702	1,722
82	13-P Oasis Cooler	07/09/91	1991	517	155.97	243.25	814	18.48	26.40%	63.54%	215	517
83	Amana Air / Electric Heat - Lab Room	04/02/97	1997	745	180.87	243.25	1,012	12.75	32.73%	70.28%	331	711
84	Carrier A/C Unit - Supt. Office S/N S0702X38461	06/28/02	2002	1,450	204.64	243.25	1,741	7.51	43.71%	79.05%	761	1,376
85	General Electric Blower S/N 27785	05/31/94	1994	885	167.96	243.25	1,295	15.59	29.15%	66.66%	377	863
86	(3) Paint Cabinet 2-Door Self-Close 40-Gallons	11/30/94	1994	575	167.96	243.25	841	15.09	29.70%	67.25%	250	565
87	Installed 2-Eye Washes and Misc. Plumbing Fixtures	12/06/94	1994	687	167.96	243.25	1,005	15.07	29.72%	67.27%	299	676
88	Coal Conveyor Alarm	01/05/95	1995	3,055	172.16	243.25	4,360	14.99	29.82%	67.37%	1,300	2,937
89	Rechargeable Battery Pack with Charger	09/17/98	1998	1,861	185.39	243.25	2,466	11.29	35.07%	72.42%	865	1,786
90				119,091			174,708				68,630	122,957
91	Grand Total			8,886,532			27,983,605				6,742,976	15,774,564
92	Capital Expenditure to achieve 20 year remaining life											10,861,326
93	"As-is" Total										6,742,976	4,913,238
Assumptions												
94	Cost Level					07/01/09						
95	Valuation Date							12/31/09				
96	Inflation Rate						2.00%					
97	Inflation Factor - To Adjust 07/01/09 Costs to 12/31/09 Cost Level						1.00%					
98	Condition Percent											
99	Present Worth Factor								2.50%	2.50%		
100	Minimum Condition								20.00%	20.00%		
101	Remaining Life - Years								5.00	20.00		
102	Handy Whitman Index for General Plant Accounts											
103	Base Year				1973							
104	Inflatation Rate				2.50%							

11.2.2 Income Based "As-Is" Value

The income valuation is based on sales forecast information developed by B&V based on energy and fuel prices contained in the Energy Market Perspective (EMP) for Indiana. Appendix C contains the information regarding this proprietary energy price forecast. B&V finds that energy prices for the Jasper, Indiana node substantially tracks the overall Indiana market. Forecast sales are determined hour by hour for those hours when the unit price of energy (market clearing price) exceeds the plant's unit cost of fuel and variable O&M. For the hours that the plant's unit cost of fuel and variable O&M exceed the market clearing price, it is assumed that the plant runs at minimum load. Sales revenues are calculated as forecast MWh sales times the average unit price of energy for the hours that the EMP price exceeds fuel and variable O&M, and at $25 per MWh for the hours that the plant operates at minimum load. In addition to the sales of energy, B&V also includes the capacity payment that Jasper receives from IMPA.

B&V forecasts fuel expense based on the City's current coal contract escalated by a factor of the EMP energy price forecast. Variable O&M is estimated at $1.25 per MWh generated. Fixed O&M, administrative, and general expense are escalated at 2.5 percent from 2008 levels.

Table 11-3 presents the "as-is" income valuation based on the present worth of the estimated future net cash flows to the City over the estimated 5 year remaining life. The discount factor is based on a tax exempt municipal revenue bond rate of 5.5 percent.

Annual cash flows (Line 59) are forecasted for 2010 through 2014. The scrap value of the JMEU plant is estimated at $25/kW or $375,000 in 2014 dollars. This scrap value does not consider removal or demolition cost. The removal cost of major plant components of value is relatively modest. Typically, the overall demolition cost substantially exceeds salvage value. The scrap value is discounted back to 2010 dollars (Line 62) and added to the Net Present Value (NPV) of the cash flows from 2010 to 2014. The estimated "as-is" income value is negative $4,543,630 (Line 63).

Table 11-3
Income Valuation of Electric Generation - "As-Is"

Line No.	Description	Variables	2010 $	2011 $	2012 $	2013 $	2014 $	scrap value $
			Projected					
1	Projection Variables							
2	Inflation - %/yr	2.50%						
3	Variable O&M - $/MWh	1.25						
4	Capacity Payment Inflation - Beginning 6/11	2.50%						
5	Net Present Value Discount Rate - %	5.50%						
6	Terminal Cap Rate - %	5.50%						
7	*Cash Inflows*							Nameplate
8	MWh Generation (Sales)							Capacity
9	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	15
10	Calculated Capacity Factor		34.34%	44.82%	47.23%	47.88%	81.99%	
11	Hours at Full Load - hours		3,008	3,926	4,137	4,194	7,182	
12	Forecast Generation (Annual Average) - MWh		43,616	56,927	59,987	60,813	104,139	
13	Annual Projected Cash Inflows from Energy Sales							
14	Forecast Annual Average Unit Price - $/MWh		52.98	53.25	54.74	54.35	65.31	
15	Forecast Sales Revenue		2,310,776	3,031,363	3,283,661	3,305,187	6,801,318	
16	Revenue from Capacity Payment		335,000	365,250	374,381	383,741	393,334	
17	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	
18	Hours at Minimun Load - hours		4,992	4,074	3,863	3,806	818	
19	Minimum Load Generation (Annual Average) - MWh		21,216	17,315	16,418	16,176	3,477	
20	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	
21	Forecast Minimum Load Revenue		530,400	432,863	410,444	404,388	86,913	
22	Other Cash Inflows		-	-	-	-	-	
23	Total Gross Cash Inflows		3,176,176	3,829,475	4,068,486	4,093,315	7,281,565	
24	*Cash Outflows*							
25	Fuel							
26	Forecast Heat Rate - BTU/kWh		14,790	14,790	14,790	14,790	14,790	
27	Forecast Cost of Coal - $/MMBTU	Indiana	3.04	3.04	3.11	3.10	3.66	
28	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	
29	Average Actual Cost of Coal - $/Ton		70.00	70.00	71.64	71.37	84.29	
30	Cost of Coal for Generation		1,963,289	2,562,458	2,763,344	2,791,052	5,644,658	
31	Forecast Minimum Load Heat Rate - BTU/kWh		18,360	18,360	18,360	18,360	18,360	
32	Cost of Coal at Minimum Load Generation		1,185,513	967,504	938,857	921,582	233,922	

Table 11-3 (Continued)
Income Valuation of Electric Generation - "As-Is"

Line No.	Description	Variables	2010 $ (Projected)	2011 $	2012 $	2013 $	2014 $	scrap value $
33	Non-Fuel O&M							
34	Variable O&M (Estimated at $1.25/MWh)		55,000	73,000	79,000	82,000	144,000	
35	Fixed O&M							
36	Operating Steam Expense		162,000	166,000	170,000	174,000	178,000	
37	Operating Electric Expense		257,000	263,000	270,000	277,000	284,000	
38	Production Steam Maintenance		120,000	123,000	126,000	129,000	132,000	
39	Other Fixed O&M		102,000	105,000	108,000	111,000	114,000	
40	Total Non-Fuel O&M		696,000	730,000	753,000	773,000	852,000	
41	Pollution Allowance Costs							
42	SO2		-	-	-	-	-	
43	NOx		-	-	-	-	-	
44	Total Pollution Alllowance Costs		-	-	-	-	-	
45	Adminstrative and General Expenses							
46	A&G Salaries		97,000	99,000	101,000	104,000	107,000	
47	Social Security Expense		50,000	51,000	52,000	53,000	54,000	
48	Employee Benefits		257,000	263,000	270,000	277,000	284,000	
49	Utilities Expense		287,000	294,000	301,000	309,000	317,000	
50	Property Insurance		105,000	108,000	111,000	114,000	117,000	
51	Other A&G Expenses		86,000	88,000	90,000	92,000	94,000	
52	Total A&G		882,000	903,000	925,000	949,000	973,000	
53	Capital Expenditures		-	-	-	-	-	
54	Renewals and Replacements		-	-	-	-	-	
55	Projected Cash Outflows		4,726,802	5,162,962	5,380,201	5,434,634	7,703,580	
56	Margin at Full Load		347,487	468,905	520,317	514,134	1,156,660	
57	Margin at Minimum Load		(655,113)	(534,642)	(528,413)	(517,194)	(147,009)	
58	Net Margin (If negative margin, assume not operated)		(307,626)	(65,736)	(8,096)	(3,060)	1,009,651	
59	Projected Net Cash Flow		(1,243,000)	(1,267,750)	(1,303,619)	(1,338,259)	(422,015)	375,000
60	*Discounted Cash Flow Value*							
61	Net Present Value (2010 - 2014)		(4,830,555)					
62	Present Value of Scrap		286,925					
63	Total Net Present Value		(4,543,630)					

11.3 Market Value with Life Extension Improvements

B&V values the JMEU plant with life extending improvements on an income based method. The discounted cash flow to determine the JMEU plant value based on three energy price forecasts: base case, high energy prices (High Energy Market) and high fuel prices (High Fuel Market). The income based value with life extending improvements ranges from negative $1.5 million to negative $19.8 million with our base case value equaling negative $12.1 million.

11.3.1 Income Based Value with Life Extension Improvements

The income valuation reflects sales forecast information developed by B&V based on energy and fuel prices contained in the EMP for Indiana. B&V finds the Jasper, Indiana node substantially tracks with the overall Indiana market. Forecast sales are determined hour by hour for those hours when the unit price of energy (market clearing price) exceeds the plant’s unit cost of fuel and variable O&M. For the hours that the plant’s unit cost of fuel and variable O&M exceed the market clearing price, it is assumed that the plant runs at minimum load. Sales revenues are calculated as forecast MWh sales times the average unit price of energy for the hours that the EMP price exceeds fuel and variable O&M, and at $25 per MWh for the hours that the plant operates at minimum load. In addition to the sales of energy, B&V also includes the capacity payment that Jasper receives from IMPA escalated by the inflation rate beginning when the current contract expires.

Fuel expense forecast is based on the City’s current coal contract escalated by a factor of the EMP energy price forecast. B&V estimates variable O&M at $1.25 per MWh generated. Fixed O&M, administrative, and general expense are escalated at 2.5 percent from 2008 levels. To achieve the forecast sales generation levels, an estimated $10.9 million in capital improvements is included. A four year capital improvement schedule is assumed with equal installments of $2.7 million beginning in 2010.

Table 11-4 presents the income valuation based on the present worth of the estimated future net cash flows to the City. The discount factor is estimated at a tax exempt municipal revenue bond rate of 5.5 percent. B&V forecasts annual cash flows (Line 59) for 2010 through 2034. It should be noted that for the years where the cost of generating at minimum load exceeds the margin at full load, it is assumed that the plant is not operated (Line 58). B&V estimates a salvage value for the plant at the end of its extended useful life. This salvage value is discounted back to 2010 dollars (Line 63) and added to the NPV of the cash flows from 2010 to 2034. The estimated income value is negative $12.1 million (Line 64).

Table 11-4
Income Valuation of Electric Generation

Line No.	Description	Variables	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
			Projected											
			$	$	$	$	$	$	$	$	$	$	$	$
1	Projection Variables													
2	Inflation - %/yr	2.50%												
3	2010 Variable O&M - $/MWh	1.25												
4	Capacity Payment Inflation - Beginning 6/11	2.50%												
5	Net Present Value Discount Rate - %	5.50%												
6	Terminal Cap Rate - %	5.50%												
7	*Cash Inflows*													
8	MWh Generation (Sales)													
9	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
10	Calculated Capacity Factor		34.34%	44.82%	47.23%	47.88%	81.99%	85.53%	87.10%	86.91%	86.22%	91.32%	91.32%	91.32%
11	Hours at Full Load - hours		3,008	3,926	4,137	4,194	7,182	7,492	7,630	7,613	7,553	8,000	8,000	8,000
12	Forecast Generation (Annual Average) - MWh		43,616	56,927	59,987	60,813	104,139	108,634	110,635	110,389	109,519	116,000	116,000	116,000
13	Annual Projected Cash Inflows from Energy Sales													
14	Forecast Annual Average Unit Price - $/MWh		52.98	53.25	54.74	54.35	65.31	66.46	67.56	68.96	71.05	71.71	71.77	72.79
15	Forecast Sales Revenue		2,310,776	3,031,363	3,283,661	3,305,187	6,801,318	7,219,816	7,474,501	7,612,391	7,781,289	8,318,360	8,325,320	8,443,640
16	Revenue from Capacity Payment		335,000	365,250	374,381	383,741	393,334	403,168	413,247	423,578	434,167	445,022	456,147	467,551
17	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
18	Hours at Minimun Load - hours		4,992	4,074	3,863	3,806	818	508	370	387	447	-	-	-
19	Minimum Load Generation (Annual Average) - MWh		21,216	17,315	16,418	16,176	3,477	2,159	1,573	1,645	1,900	-	-	-
20	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
21	Forecast Minimum Load Revenue		530,400	432,863	410,444	404,388	86,913	53,975	39,313	41,119	47,494	-	-	-
22	Other Cash Inflows		-	-	-	-	-	-	-	-	-	-	-	-
23	Total Gross Cash Inflows		3,176,176	3,829,475	4,068,486	4,093,315	7,281,565	7,676,958	7,927,060	8,077,088	8,262,951	8,763,382	8,781,467	8,911,191
24	*Cash Outflows*													
25	Fuel													
26	Forecast Heat Rate - BTU/kWh		14,790	14,790	14,790	14,790	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500
27	Forecast Cost of Coal - $/MMBTU	Indiana	3.04	3.04	3.11	3.10	3.66	3.71	3.75	3.78	3.83	3.89	3.89	3.93
28	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500
29	Average Actual Cost of Coal - $/Ton		70.00	70.00	71.64	71.37	84.29	85.38	86.18	87.03	88.19	89.38	89.58	90.43
30	Cost of Coal for Generation		1,963,289	2,562,458	2,763,344	2,791,052	5,533,978	5,847,194	6,010,909	6,056,408	6,089,276	6,536,502	6,550,916	6,613,255

Table 11-4 (Continued)
Income Valuation of Electric Generation

Line No.	Description	Variables	2010 $	2011 $	2012 $	2013 $	2014 $	2015 $	2016 $	2017 $	2018 $	2019 $	2020 $	2021 $
			Projected											
31	Forecast Minimum Load Heat Rate - BTU/kWh		18,360	18,360	18,360	18,360	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
32	Cost of Coal at Minimum Load Generation		1,185,513	967,504	938,857	921,582	229,335	144,258	106,058	112,020	131,123	-	-	-
33	Non-Fuel O&M													
34	Variable O&M		81,000	95,000	100,000	104,000	148,000	157,000	163,000	166,000	170,000	181,000	186,000	190,000
35	Fixed O&M													
36	Operating Steam Expense		162,000	166,000	170,000	174,000	178,000	182,000	187,000	192,000	197,000	202,000	207,000	212,000
37	Operating Electric Expense		257,000	263,000	270,000	277,000	284,000	291,000	298,000	305,000	313,000	321,000	329,000	337,000
38	Production Steam Maintenance		120,000	123,000	126,000	129,000	132,000	135,000	138,000	141,000	145,000	149,000	153,000	157,000
39	Other Fixed O&M		102,000	105,000	108,000	111,000	114,000	117,000	120,000	123,000	126,000	129,000	132,000	135,000
40	Total Non-Fuel O&M		722,000	752,000	774,000	795,000	856,000	882,000	906,000	927,000	951,000	982,000	1,007,000	1,031,000
41	Pollution Allowance Costs													
42	SO2		-	-	-	-	-	-	-	-	-	-	-	-
43	NOx		-	-	-	-	-	-	-	-	-	-	-	-
44	Total Pollution Alllowance Costs		-	-	-	-	-	-	-	-	-	-	-	-
45	Adminstrative and General Expenses													
46	A&G Salaries		97,000	99,000	101,000	104,000	107,000	110,000	113,000	116,000	119,000	122,000	125,000	128,000
47	Social Security Expense		50,000	51,000	52,000	53,000	54,000	55,000	56,000	57,000	58,000	59,000	60,000	62,000
48	Employee Benefits		257,000	263,000	270,000	277,000	284,000	291,000	298,000	305,000	313,000	321,000	329,000	337,000
49	Utilities Expense		287,000	294,000	301,000	309,000	317,000	325,000	333,000	341,000	350,000	359,000	368,000	377,000
50	Property Insurance		105,000	108,000	111,000	114,000	117,000	120,000	123,000	126,000	129,000	132,000	135,000	138,000
51	Other A&G Expenses		86,000	88,000	90,000	92,000	94,000	96,000	98,000	100,000	103,000	106,000	109,000	112,000
52	Total A&G		882,000	903,000	925,000	949,000	973,000	997,000	1,021,000	1,045,000	1,072,000	1,099,000	1,126,000	1,154,000
53	Capital Expenditures		2,715,331	2,715,331	2,715,331	2,715,331	-	-	-	-	-	-	-	-
54	Renewals and Replacements		-	-	-	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
55	Projected Cash Outflows		7,468,134	7,900,293	8,116,532	8,171,965	7,792,313	8,070,452	8,243,967	8,340,428	8,443,399	8,817,502	8,883,916	8,998,255
56	Margin at Full Load		347,487	468,905	520,317	514,134	1,267,340	1,372,621	1,463,592	1,555,983	1,692,013	1,781,858	1,774,404	1,830,385
57	Margin at Minimum Load		(655,113)	(534,642)	(528,413)	(517,194)	(142,423)	(90,283)	(66,745)	(70,901)	(83,629)	-	-	-
58	Net Margin (If negative, assume not operated)		(307,626)	(65,736)	(8,096)	(3,060)	1,124,917	1,282,339	1,396,846	1,485,082	1,608,384	1,781,858	1,774,404	1,830,385
59	Projected Net Cash Flow		(3,984,331)	(4,005,081)	(4,039,950)	(4,075,591)	(510,749)	(393,494)	(316,907)	(263,340)	(180,448)	(54,120)	(102,448)	(87,064)
60	*Discounted Cash Flow Value*													
61	Net Present Value (2010 - 2034)		(12,292,900)											
62	Future Salvage Value		678,272											
63	Present Value of Future Salvage		177,866											
64	Total Net Present Value		(12,115,035)											

Table 11-4 (Continued)
Income Valuation of Electric Generation

Line No.	Description	Variables	Projected 2022 $	2023 $	2024 $	2025 $	2026 $	2027 $	2028 $	2029 $	2030 $	2031 $	2032 $	2033 $	2034 $
1	Projection Variables														
2	Inflation - %/yr	2.50%													
3	2010 Variable O&M - $/MWh	1.25													
4	Capacity Payment Inflation - Beginning 6/11	2.50%													
5	Net Present Value Discount Rate - %	5.50%													
6	Terminal Cap Rate - %	5.50%													
7	*Cash Inflows*														
8	MWh Generation (Sales)														
9	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
10	Calculated Capacity Factor		91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%
11	Hours at Full Load - hours		8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
12	Forecast Generation (Annual Average) - MWh		116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000
13	Annual Projected Cash Inflows from Energy Sales														
14	Forecast Annual Average Unit Price - $/MWh		74.42	76.20	78.51	80.89	83.31	85.76	88.23	90.65	92.95	95.24	97.56	99.85	102.17
15	Forecast Sales Revenue		8,632,720	8,839,200	9,107,160	9,383,240	9,663,960	9,948,160	10,234,680	10,515,400	10,782,200	11,047,840	11,316,960	11,582,600	11,851,720
16	Revenue from Capacity Payment		479,240	491,221	503,501	516,089	528,991	542,216	555,771	569,665	583,907	598,505	613,467	628,804	644,524
17	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
18	Hours at Minimun Load - hours		-	-	-	-	-	-	-	-	-	-	-	-	-
19	Minimum Load Generation (Annual Average) - MWh		-	-	-	-	-	-	-	-	-	-	-	-	-
20	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
21	Forecast Minimum Load Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-
22	Other Cash Inflows		-	-	-	-	-	-	-	-	-	-	-	-	-
23	Total Gross Cash Inflows		9,111,960	9,330,421	9,610,661	9,899,329	10,192,951	10,490,376	10,790,451	11,085,065	11,366,107	11,646,345	11,930,427	12,211,404	12,496,244
24	*Cash Outflows*														
25	Fuel														
26	Forecast Heat Rate - BTU/kWh		14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500
27	Forecast Cost of Coal - $/MMBTU	Indiana	3.98	4.03	4.09	4.16	4.22	4.28	4.34	4.40	4.46	4.51	4.57	4.62	4.67
28	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500
29	Average Actual Cost of Coal - $/Ton		91.50	92.72	94.16	95.61	97.05	98.47	99.88	101.25	102.53	103.79	105.05	106.28	107.50
30	Cost of Coal for Generation		6,691,639	6,780,981	6,885,746	6,992,195	7,097,483	7,201,233	7,304,294	7,404,372	7,497,998	7,590,469	7,682,394	7,772,112	7,861,359

Table 11-4 (Continued)
Income Valuation of Electric Generation

Line No.	Description	Variables	Projected 2022 $	2023 $	2024 $	2025 $	2026 $	2027 $	2028 $	2029 $	2030 $	2031 $	2032 $	2033 $	2034 $
31	Forecast Minimum Load Heat Rate - BTU/kWh		18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
32	Cost of Coal at Minimum Load Generation		-	-	-	-	-	-	-	-	-	-	-	-	-
33	Non-Fuel O&M														
34	Variable O&M		195,000	200,000	205,000	210,000	215,000	221,000	226,000	232,000	238,000	244,000	250,000	256,000	262,000
35	Fixed O&M														
36	Operating Steam Expense		217,000	222,000	228,000	234,000	240,000	246,000	252,000	258,000	264,000	271,000	278,000	285,000	292,000
37	Operating Electric Expense		345,000	354,000	363,000	372,000	381,000	391,000	401,000	411,000	421,000	432,000	443,000	454,000	465,000
38	Production Steam Maintenance		161,000	165,000	169,000	173,000	177,000	181,000	186,000	191,000	196,000	201,000	206,000	211,000	216,000
39	Other Fixed O&M		138,000	141,000	145,000	149,000	153,000	157,000	161,000	165,000	169,000	173,000	177,000	181,000	186,000
40	Total Non-Fuel O&M		1,056,000	1,082,000	1,110,000	1,138,000	1,166,000	1,196,000	1,226,000	1,257,000	1,288,000	1,321,000	1,354,000	1,387,000	1,421,000
41	Pollution Allowance Costs														
42	SO2		-	-	-	-	-	-	-	-	-	-	-	-	-
43	NOx		-	-	-	-	-	-	-	-	-	-	-	-	-
44	Total Pollution Alllowance Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
45	Adminstrative and General Expenses														
46	A&G Salaries		131,000	134,000	137,000	140,000	144,000	148,000	152,000	156,000	160,000	164,000	168,000	172,000	176,000
47	Social Security Expense		64,000	66,000	68,000	70,000	72,000	74,000	76,000	78,000	80,000	82,000	84,000	86,000	88,000
48	Employee Benefits		345,000	354,000	363,000	372,000	381,000	391,000	401,000	411,000	421,000	432,000	443,000	454,000	465,000
49	Utilities Expense		386,000	396,000	406,000	416,000	426,000	437,000	448,000	459,000	470,000	482,000	494,000	506,000	519,000
50	Property Insurance		141,000	145,000	149,000	153,000	157,000	161,000	165,000	169,000	173,000	177,000	181,000	186,000	191,000
51	Other A&G Expenses		115,000	118,000	121,000	124,000	127,000	130,000	133,000	136,000	139,000	142,000	146,000	150,000	154,000
52	Total A&G		1,182,000	1,213,000	1,244,000	1,275,000	1,307,000	1,341,000	1,375,000	1,409,000	1,443,000	1,479,000	1,516,000	1,554,000	1,593,000
53	Capital Expenditures		-	-	-	-	-	-	-	-	-	-	-	-	-
54	Renewals and Replacements		200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	-	-	-	-	-
55	Projected Cash Outflows		9,129,639	9,275,981	9,439,746	9,605,195	9,770,483	9,938,233	10,105,294	10,270,372	10,228,998	10,390,469	10,552,394	10,713,112	10,875,359
56	Margin at Full Load		1,941,081	2,058,219	2,221,414	2,391,045	2,566,477	2,746,927	2,930,386	3,111,028	3,284,202	3,457,371	3,634,566	3,810,488	3,990,361
57	Margin at Minimum Load		-	-	-	-	-	-	-	-	-	-	-	-	-
58	Net Margin (If negative, assume not operated)		1,941,081	2,058,219	2,221,414	2,391,045	2,566,477	2,746,927	2,930,386	3,111,028	3,284,202	3,457,371	3,634,566	3,810,488	3,990,361
59	Projected Net Cash Flow		(17,680)	54,439	170,915	294,134	422,468	552,143	685,157	814,693	1,137,109	1,255,875	1,378,034	1,498,292	1,620,885
60	*Discounted Cash Flow Value*														
61	Net Present Value (2010 - 2034)														
62	Future Salvage Value														
63	Present Value of Future Salvage														
64	Total Net Present Value														

In addition to the base case income valuation with life extension described above, the income value estimate is based on two other scenarios. The plant is valued assuming an energy market and capacity payment that are 10 percent higher than the base case in one scenario, and assuming a fuel market that is 10 percent higher than our base case in the second scenario. Table 11-5 presents the income valuation if the energy market prices are 10 percent higher than the EMP price for Indiana and the IMPA capacity payment is 10 percent higher than the base case forecast. Table 11-6 presents the income valuation if the fuel prices are 10 percent higher than the base case forecast. The estimated income value of the JMEU plant is negative $1.5 million under high energy market price scenario and negative $19.8 million under high fuel price scenario.

11.4 Salvage Value

11.4.1 Scrap Value

B&V estimates the scrap value of the major components of the plant (turbine, generator, condenser) based on a nameplate installed capacity value of $25/kW based on demolition studies B&V has performed for other utilities. It is estimated that the scrap value of the JMEU plant is $375,000 in 2009 dollars. This scrap value does not consider removal or demolition cost. The removal cost of major plant components of value is relatively modest. However, the overall demolition cost typically exceeds salvage value.

For certain relatively small, self-contained plant components (e.g., turbine, generator, and condenser) there is typically a relatively strong market both domestically and internationally. This equipment is relatively easy to remove and transport to other sites for use in new or retrofit facilities. However, for other plant components, the cost of dismantling, transporting, and reassembly typically substantially exceeds the salvage value. Typically, the value of these components does not exceed scrap value. Although scrap markets have been somewhat volatile, scrap value has seldom exceeded dismantling cost.

11.4.2 Used Equipment Market

Another option would be for the City to sell the plant equipment through a used equipment broker. Equipment, such as the components at the JMEU plant, sometimes are of particular interest to underdeveloped countries; normally these countries contact used equipment brokers. There are several brokers for used equipment, and one reference for the City is the following Web address “www.coalfiredboilers.com.”

Table 11-5
Income Valuation of Electric Generation - High Energy Market

Line No.	Description	Variables	2010 $	2011 $	2012 $	2013 $	2014 $	2015 $	2016 $	2017 $	2018 $	2019 $	2020 $	2021 $
			Projected											
1	Projection Variables													
2	Inflation - %/yr	2.50%												
3	Variable O&M - $/MWh	1.25												
4	Energy & Capacity payment price markup	10%												
5	Capacity Payment Inflation - Beginning 6/11	2.50%												
6	Net Present Value Discount Rate - %	5.50%												
7	Terminal Cap Rate - %	5.50%												
8	*Cash Inflows*													
9	MWh Generation (Sales)													
10	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
11	Calculated Capacity Factor		52.05%	59.55%	61.45%	60.90%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%
12	Hours at Full Load - hours		4,560	5,217	5,383	5,335	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
13	Forecast Generation (Annual Average) - MWh		66,120	75,647	78,054	77,358	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000
14	Annual Projected Cash Inflows from Energy Sales													
15	Forecast Annual Average Unit Price - $/MWh		55.05	56.13	57.88	57.68	69.50	71.12	72.39	73.82	75.79	77.80	78.16	79.63
16	Forecast Sales Revenue		3,639,906	4,246,038	4,517,737	4,461,981	8,062,000	8,249,920	8,397,240	8,563,120	8,791,640	9,024,800	9,066,560	9,237,080
17	Revenue from Capacity Payment		335,000	386,556	411,819	422,115	432,668	443,484	454,572	465,936	477,584	489,524	501,762	514,306
18	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
19	Hours at Minimun Load - hours		3,440	2,783	2,617	2,665	-	-	-	-	-	-	-	-
20	Minimum Load Generation (Annual Average) - MWh		14,620	11,828	11,122	11,326	-	-	-	-	-	-	-	-
21	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
22	Forecast Minimum Load Revenue		365,500	295,694	278,056	283,156	-	-	-	-	-	-	-	-
23	Other Cash Inflows		-	-	-	-	-	-	-	-	-	-	-	-
24	Total Gross Cash Inflows		4,340,406	4,928,288	5,207,612	5,167,252	8,494,668	8,693,404	8,851,812	9,029,056	9,269,224	9,514,324	9,568,322	9,751,386
25	*Cash Outflows*													
26	Fuel													
27	Forecast Heat Rate - BTU/kWh		14,790	14,790	14,790	14,790	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500
28	Forecast Cost of Coal - $/MMBTU	Indiana	3.04	3.04	3.11	3.10	3.66	3.71	3.75	3.78	3.83	3.89	3.89	3.93
29	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500
30	Average Actual Cost of Coal - $/Ton		70.00	70.00	71.64	71.37	84.29	85.38	86.18	87.03	88.19	89.38	89.58	90.43
31	Cost of Coal for Generation		2,976,262	3,405,079	3,595,620	3,550,373	6,164,275	6,243,667	6,302,395	6,364,280	6,449,650	6,536,502	6,550,916	6,613,255

Table 11-5 (Continued)
Income Valuation of Electric Generation - High Energy Market

Line No.	Description	Variables	Projected											
			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
			$	$	$	$	$	$	$	$	$	$	$	$
32	Forecast Minimum Load Heat Rate - BTU/kWh		18,360	18,360	18,360	18,360	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
33	Cost of Coal at Minimum Load Generation		816,940	660,914	636,031	645,301	-	-	-	-	-	-	-	-
34	Non-Fuel O&M													
35	Variable O&M (Estimated at $1.25/MWh)		83,000	97,000	103,000	104,000	160,000	164,000	168,000	172,000	177,000	181,000	186,000	190,000
36	Fixed O&M													
37	Operating Steam Expense		162,000	166,000	170,000	174,000	178,000	182,000	187,000	192,000	197,000	202,000	207,000	212,000
38	Operating Electric Expense		257,000	263,000	270,000	277,000	284,000	291,000	298,000	305,000	313,000	321,000	329,000	337,000
39	Production Steam Maintenance		120,000	123,000	126,000	129,000	132,000	135,000	138,000	141,000	145,000	149,000	153,000	157,000
40	Other Fixed O&M		102,000	105,000	108,000	111,000	114,000	117,000	120,000	123,000	126,000	129,000	132,000	135,000
41	Total Non-Fuel O&M		724,000	754,000	777,000	795,000	868,000	889,000	911,000	933,000	958,000	982,000	1,007,000	1,031,000
42	Pollution Allowance Costs													
43	SO2		-	-	-	-	-	-	-	-	-	-	-	-
44	NOx		-	-	-	-	-	-	-	-	-	-	-	-
45	Total Pollution Alllowance Costs		-	-	-	-	-	-	-	-	-	-	-	-
46	Adminstrative and General Expenses													
47	A&G Salaries		97,000	99,000	101,000	104,000	107,000	110,000	113,000	116,000	119,000	122,000	125,000	128,000
48	Social Security Expense		50,000	51,000	52,000	53,000	54,000	55,000	56,000	57,000	58,000	59,000	60,000	62,000
49	Employee Benefits		257,000	263,000	270,000	277,000	284,000	291,000	298,000	305,000	313,000	321,000	329,000	337,000
50	Utilities Expense		287,000	294,000	301,000	309,000	317,000	325,000	333,000	341,000	350,000	359,000	368,000	377,000
51	Property Insurance		105,000	108,000	111,000	114,000	117,000	120,000	123,000	126,000	129,000	132,000	135,000	138,000
52	Other A&G Expenses		86,000	88,000	90,000	92,000	94,000	96,000	98,000	100,000	103,000	106,000	109,000	112,000
53	Total A&G		882,000	903,000	925,000	949,000	973,000	997,000	1,021,000	1,045,000	1,072,000	1,099,000	1,126,000	1,154,000
54	Capital Expenditures		2,715,331	2,715,331	2,715,331	2,715,331	-	-	-	-	-	-	-	-
55	Renewals and Replacements		-	-	-	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
56	Projected Cash Outflows		8,114,534	8,438,325	8,648,982	8,655,005	8,205,275	8,329,667	8,434,395	8,542,280	8,679,650	8,817,502	8,883,916	8,998,255
57	Margin at Full Load		663,644	840,959	922,117	911,608	1,897,725	2,006,253	2,094,845	2,198,840	2,341,990	2,488,298	2,515,644	2,623,825
58	Margin at Minimum Load		(451,440)	(365,220)	(357,975)	(362,145)	-	-	-	-	-	-	-	-
59	Net Margin (If negative, assume not operated)		212,203	475,739	564,142	549,463	1,897,725	2,006,253	2,094,845	2,198,840	2,341,990	2,488,298	2,515,644	2,623,825
60	Projected Net Cash Flow		(3,774,128)	(3,510,037)	(3,441,370)	(3,487,753)	289,392	363,737	417,417	486,776	589,574	696,822	684,406	753,131
61	*Discounted Cash Flow Value*													
62	Net Present Value (2010 - 2034)		(1,691,204)											
63	Future Salvage Value		678,272											
64	Present Value of Future Salvage		177,866											
65	Total Net Present Value		(1,513,338)											

Table 11-5 (Continued)
Income Valuation of Electric Generation - High Energy Market

			Projected												
Line No.	Description	Variables	2022 $	2023 $	2024 $	2025 $	2026 $	2027 $	2028 $	2029 $	2030 $	2031 $	2032 $	2033 $	2034 $
1	Projection Variables														
2	Inflation - %/yr	2.50%													
3	Variable O&M - $/MWh	1.25													
4	Energy & Capacity payment price markup	10%													
5	Capacity Payment Inflation - Beginning 6/11	2.50%													
6	Net Present Value Discount Rate - %	5.50%													
7	Terminal Cap Rate - %	5.50%													
8	*Cash Inflows*														
9	MWh Generation (Sales)														
10	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
11	Calculated Capacity Factor		91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%
12	Hours at Full Load - hours		8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
13	Forecast Generation (Annual Average) - MWh		116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000
14	Annual Projected Cash Inflows from Energy Sales														
15	Forecast Annual Average Unit Price - $/MWh		81.52	83.69	86.28	88.94	91.62	94.30	97.02	99.68	102.21	104.73	107.29	109.81	112.36
16	Forecast Sales Revenue		9,456,320	9,708,040	10,008,480	10,317,040	10,627,920	10,938,800	11,254,320	11,562,880	11,856,360	12,148,680	12,445,640	12,737,960	13,033,760
17	Revenue from Capacity Payment		527,164	540,343	553,851	567,698	581,890	596,437	611,348	626,632	642,298	658,355	674,814	691,684	708,976
18	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
19	Hours at Minimun Load - hours		-	-	-	-	-	-	-	-	-	-	-	-	-
20	Minimum Load Generation (Annual Average) - MWh		-	-	-	-	-	-	-	-	-	-	-	-	-
21	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
22	Forecast Minimum Load Revenue		-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Cash Inflows		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Gross Cash Inflows		9,983,484	10,248,383	10,562,331	10,884,738	11,209,810	11,535,237	11,865,668	12,189,512	12,498,658	12,807,035	13,120,454	13,429,644	13,742,736
25	*Cash Outflows*														
26	Fuel														
27	Forecast Heat Rate - BTU/kWh		14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500
28	Forecast Cost of Coal - $/MMBTU	Indiana	3.98	4.03	4.09	4.16	4.22	4.28	4.34	4.40	4.46	4.51	4.57	4.62	4.67
29	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500
30	Average Actual Cost of Coal - $/Ton		91.50	92.72	94.16	95.61	97.05	98.47	99.88	101.25	102.53	103.79	105.05	106.28	107.50
31	Cost of Coal for Generation		6,691,639	6,780,981	6,885,746	6,992,195	7,097,483	7,201,233	7,304,294	7,404,372	7,497,998	7,590,469	7,682,394	7,772,112	7,861,359

Table 11-5 (Continued)
Income Valuation of Electric Generation - High Energy Market

Line No.	Description	Variables	Projected												
			2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
			$	$	$	$	$	$	$	$	$	$	$	$	$
32	Forecast Minimum Load Heat Rate - BTU/kWh		18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
33	Cost of Coal at Minimum Load Generation		-	-	-	-	-	-	-	-	-	-	-	-	-
34	Non-Fuel O&M														
35	Variable O&M (Estimated at $1.25/MWh)		195,000	200,000	205,000	210,000	215,000	221,000	226,000	232,000	238,000	244,000	250,000	256,000	262,000
36	Fixed O&M														
37	Operating Steam Expense		217,000	222,000	228,000	234,000	240,000	246,000	252,000	258,000	264,000	271,000	278,000	285,000	292,000
38	Operating Electric Expense		345,000	354,000	363,000	372,000	381,000	391,000	401,000	411,000	421,000	432,000	443,000	454,000	465,000
39	Production Steam Maintenance		161,000	165,000	169,000	173,000	177,000	181,000	186,000	191,000	196,000	201,000	206,000	211,000	216,000
40	Other Fixed O&M		138,000	141,000	145,000	149,000	153,000	157,000	161,000	165,000	169,000	173,000	177,000	181,000	186,000
41	Total Non-Fuel O&M		1,056,000	1,082,000	1,110,000	1,138,000	1,166,000	1,196,000	1,226,000	1,257,000	1,288,000	1,321,000	1,354,000	1,387,000	1,421,000
42	Pollution Allowance Costs														
43	SO2		-	-	-	-	-	-	-	-	-	-	-	-	-
44	NOx		-	-	-	-	-	-	-	-	-	-	-	-	-
45	Total Pollution Alllowance Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
46	Adminstrative and General Expenses														
47	A&G Salaries		131,000	134,000	137,000	140,000	144,000	148,000	152,000	156,000	160,000	164,000	168,000	172,000	176,000
48	Social Security Expense		64,000	66,000	68,000	70,000	72,000	74,000	76,000	78,000	80,000	82,000	84,000	86,000	88,000
49	Employee Benefits		345,000	354,000	363,000	372,000	381,000	391,000	401,000	411,000	421,000	432,000	443,000	454,000	465,000
50	Utilities Expense		386,000	396,000	406,000	416,000	426,000	437,000	448,000	459,000	470,000	482,000	494,000	506,000	519,000
51	Property Insurance		141,000	145,000	149,000	153,000	157,000	161,000	165,000	169,000	173,000	177,000	181,000	186,000	191,000
52	Other A&G Expenses		115,000	118,000	121,000	124,000	127,000	130,000	133,000	136,000	139,000	142,000	146,000	150,000	154,000
53	Total A&G		1,182,000	1,213,000	1,244,000	1,275,000	1,307,000	1,341,000	1,375,000	1,409,000	1,443,000	1,479,000	1,516,000	1,554,000	1,593,000
54	Capital Expenditures		-	-	-	-	-	-	-	-	-	-	-	-	-
55	Renewals and Replacements		200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	-	-	-	-	-
56	Projected Cash Outflows		9,129,639	9,275,981	9,439,746	9,605,195	9,770,483	9,938,233	10,105,294	10,270,372	10,228,998	10,390,469	10,552,394	10,713,112	10,875,359
57	Margin at Full Load		2,764,681	2,927,059	3,122,734	3,324,845	3,530,437	3,737,567	3,950,026	4,158,508	4,358,362	4,558,211	4,763,246	4,965,848	5,172,401
58	Margin at Minimum Load		-	-	-	-	-	-	-	-	-	-	-	-	-
59	Net Margin (If negative, assume not operated)		2,764,681	2,927,059	3,122,734	3,324,845	3,530,437	3,737,567	3,950,026	4,158,508	4,358,362	4,558,211	4,763,246	4,965,848	5,172,401
60	Projected Net Cash Flow		853,844	972,401	1,122,585	1,279,543	1,439,327	1,597,005	1,760,374	1,919,139	2,269,660	2,416,566	2,568,060	2,716,532	2,867,377
61	*Discounted Cash Flow Value*														
62	Net Present Value (2010 - 2034)														
63	Future Salvage Value														
64	Present Value of Future Salvage														
65	Total Net Present Value														

Table 11-6
Income Valuation of Electric Generation - High Fuel Market

Line No.	Description	Variables	2010 $	2011 $	2012 $	2013 $	2014 $	2015 $	2016 $	2017 $	2018 $	2019 $	2020 $	2021 $
			Projected											
1	Projection Variables													
2	Inflation - %/yr	2.50%												
3	Variable O&M - $/MWh	1.25												
4	High fuel price markup	10%												
5	Capacity Payment Inflation - Beginning 6/11	2.50%												
6	Net Present Value Discount Rate - %	5.50%												
7	Terminal Cap Rate - %	5.50%												
8	*Cash Inflows*													
9	MWh Generation (Sales)													
10	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
11	Calculated Capacity Factor		15.58%	21.68%	22.26%	21.91%	57.72%	61.15%	62.97%	65.63%	66.53%	72.74%	74.73%	77.77%
12	Hours at Full Load - hours		1,365	1,899	1,950	1,919	5,056	5,357	5,516	5,749	5,828	6,372	6,546	6,813
13	Forecast Generation (Annual Average) - MWh		19,793	27,536	28,275	27,826	73,312	77,677	79,982	83,361	84,506	92,394	94,917	98,789
14	Annual Projected Cash Inflows from Energy Sales													
15	Forecast Annual Average Unit Price - $/MWh		58.71	58.47	60.63	59.96	68.67	69.83	71.11	72.21	74.41	74.85	74.75	75.54
16	Forecast Sales Revenue		1,162,018	1,610,001	1,714,313	1,668,417	5,034,335	5,424,150	5,687,520	6,019,462	6,288,091	6,915,691	7,095,046	7,462,483
17	Revenue from Capacity Payment		335,000	365,250	374,381	383,741	393,334	403,168	413,247	423,578	434,167	445,022	456,147	467,551
18	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
19	Hours at Minimun Load - hours		6,635	6,101	6,050	6,081	2,944	2,643	2,484	2,251	2,172	1,628	1,454	1,187
20	Minimum Load Generation (Annual Average) - MWh		28,199	25,929	25,713	25,844	12,512	11,233	10,557	9,567	9,231	6,919	6,180	5,045
21	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
22	Forecast Minimum Load Revenue		704,969	648,231	642,813	646,106	312,800	280,819	263,925	239,169	230,775	172,975	154,488	126,119
23	Other Cash Inflows		-	-	-	-	-	-	-	-	-	-	-	-
24	Total Gross Cash Inflows		2,201,986	2,623,482	2,731,507	2,698,264	5,740,469	6,108,136	6,364,692	6,682,208	6,953,034	7,533,688	7,705,680	8,056,153
25	*Cash Outflows*													
26	Fuel													
27	Forecast Heat Rate - BTU/kWh		14,790	14,790	14,790	14,790	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500
28	Forecast Cost of Coal - $/MMBTU	Indiana	3.04	3.04	3.43	3.41	4.03	4.08	4.12	4.16	4.22	4.27	4.28	4.32
29	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500
30	Average Actual Cost of Coal - $/Ton		70.00	70.00	78.80	78.51	92.72	93.91	94.80	95.73	97.01	98.32	98.54	99.47
31	Cost of Coal for Generation		890,921	1,239,457	1,432,771	1,404,776	4,285,404	4,599,007	4,780,051	5,030,884	5,168,427	5,726,956	5,896,315	6,195,215

Table 11-6 (Continued)
Income Valuation of Electric Generation - High Fuel Market

Line No.	Description	Variables	Projected											
			2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
			$	$	$	$	$	$	$	$	$	$	$	$
32	Forecast Minimum Load Heat Rate - BTU/kWh		18,360	18,360	18,360	18,360	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
33	Cost of Coal at Minimum Load Generation		1,575,697	1,448,881	1,617,420	1,619,693	907,921	825,591	783,223	716,726	700,848	532,388	476,535	392,730
34	Non-Fuel O&M													
35	Variable O&M (Estimated at $1.25/MWh)		25,000	35,000	37,000	37,000	101,000	110,000	116,000	124,000	129,000	144,000	152,000	162,000
36	Fixed O&M													
37	Operating Steam Expense		162,000	166,000	170,000	174,000	178,000	182,000	187,000	192,000	197,000	202,000	207,000	212,000
38	Operating Electric Expense		257,000	263,000	270,000	277,000	284,000	291,000	298,000	305,000	313,000	321,000	329,000	337,000
39	Production Steam Maintenance		120,000	123,000	126,000	129,000	132,000	135,000	138,000	141,000	145,000	149,000	153,000	157,000
40	Other Fixed O&M		102,000	105,000	108,000	111,000	114,000	117,000	120,000	123,000	126,000	129,000	132,000	135,000
41	Total Non-Fuel O&M		666,000	692,000	711,000	728,000	809,000	835,000	859,000	885,000	910,000	945,000	973,000	1,003,000
42	Pollution Allowance Costs													
43	SO2		-	-	-	-	-	-	-	-	-	-	-	-
44	NOx		-	-	-	-	-	-	-	-	-	-	-	-
45	Total Pollution Alllowance Costs		-	-	-	-	-	-	-	-	-	-	-	-
46	Adminstrative and General Expenses													
47	A&G Salaries		97,000	99,000	101,000	104,000	107,000	110,000	113,000	116,000	119,000	122,000	125,000	128,000
48	Social Security Expense		50,000	51,000	52,000	53,000	54,000	55,000	56,000	57,000	58,000	59,000	60,000	62,000
49	Employee Benefits		257,000	263,000	270,000	277,000	284,000	291,000	298,000	305,000	313,000	321,000	329,000	337,000
50	Utilities Expense		287,000	294,000	301,000	309,000	317,000	325,000	333,000	341,000	350,000	359,000	368,000	377,000
51	Property Insurance		105,000	108,000	111,000	114,000	117,000	120,000	123,000	126,000	129,000	132,000	135,000	138,000
52	Other A&G Expenses		86,000	88,000	90,000	92,000	94,000	96,000	98,000	100,000	103,000	106,000	109,000	112,000
53	Total A&G		882,000	903,000	925,000	949,000	973,000	997,000	1,021,000	1,045,000	1,072,000	1,099,000	1,126,000	1,154,000
54	Capital Expenditures		2,715,331	2,715,331	2,715,331	2,715,331	-	-	-	-	-	-	-	-
55	Renewals and Replacements		-	-	-	-	200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000
56	Projected Cash Outflows		6,729,949	6,998,669	7,401,522	7,416,801	7,175,325	7,456,598	7,643,274	7,877,609	8,051,276	8,503,343	8,671,850	8,944,945
57	Margin at Full Load		271,097	370,544	281,543	263,641	748,931	825,143	907,469	988,578	1,119,664	1,188,735	1,198,730	1,267,268
58	Margin at Minimum Load		(870,728)	(800,650)	(974,608)	(973,587)	(595,121)	(544,772)	(519,298)	(477,557)	(470,073)	(359,413)	(322,047)	(266,611)
59	Net Margin (If negative, assume not operated)		(599,631)	(430,106)	(693,065)	(709,946)	153,810	280,370	388,171	511,021	649,591	829,322	876,683	1,000,657
60	Projected Net Cash Flow		(3,928,331)	(3,945,081)	(3,976,950)	(4,008,591)	(1,434,856)	(1,348,462)	(1,278,582)	(1,195,401)	(1,098,242)	(969,656)	(966,170)	(888,792)
61	*Discounted Cash Flow Value*													
62	Net Present Value (2010 - 2034)		(19,985,359)											
63	Future Salvage Value		678,272											
64	Present Value of Future Salvage		177,866											
65	Total Net Present Value		(19,807,493)											

Table 11-6 (Continued)
Income Valuation of Electric Generation - High Fuel Market

Line No.	Description	Variables	2022 $	2023 $	2024 $	2025 $	2026 $	2027 $	2028 $	2029 $	2030 $	2031 $	2032 $	2033 $	2034 $
			Projected												
1	Projection Variables														
2	Inflation - %/yr	2.50%													
3	Variable O&M - $/MWh	1.25													
4	High fuel price markup	10%													
5	Capacity Payment Inflation - Beginning 6/11	2.50%													
6	Net Present Value Discount Rate - %	5.50%													
7	Terminal Cap Rate - %	5.50%													
8	*Cash Inflows*														
9	MWh Generation (Sales)														
10	Plant Capacity - MW		14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5	14.5
11	Calculated Capacity Factor		81.60%	85.92%	88.77%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%	91.32%
12	Hours at Full Load - hours		7,148	7,527	7,776	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000
13	Forecast Generation (Annual Average) - MWh		103,646	109,142	112,752	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000	116,000
14	Annual Projected Cash Inflows from Energy Sales														
15	Forecast Annual Average Unit Price - $/MWh		76.77	78.15	80.20	82.19	84.29	86.46	88.67	90.98	93.12	95.38	97.69	100.00	102.31
16	Forecast Sales Revenue		7,956,903	8,529,408	9,042,710	9,534,040	9,777,640	10,029,360	10,285,720	10,553,680	10,801,920	11,064,080	11,332,040	11,600,000	11,867,960
17	Revenue from Capacity Payment		479,240	491,221	503,501	516,089	528,991	542,216	555,771	569,665	583,907	598,505	613,467	628,804	644,524
18	Minimun Load Net Output - MW		4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25	4.25
19	Hours at Minimun Load - hours		852	473	224	-	-	-	-	-	-	-	-	-	-
20	Minimum Load Generation (Annual Average) - MWh		3,621	2,010	952	-	-	-	-	-	-	-	-	-	-
21	Forecast Unit Price at Minimum Load - $/MWh		25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00
22	Forecast Minimum Load Revenue		90,525	50,256	23,800	-	-	-	-	-	-	-	-	-	-
23	Other Cash Inflows		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Total Gross Cash Inflows		8,526,668	9,070,885	9,570,012	10,050,129	10,306,631	10,571,576	10,841,491	11,123,345	11,385,827	11,662,585	11,945,507	12,228,804	12,512,484
25	*Cash Outflows*														
26	Fuel														
27	Forecast Heat Rate - BTU/kWh		14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500	14,500
28	Forecast Cost of Coal - $/MMBTU	Indiana	4.38	4.43	4.50	4.57	4.64	4.71	4.78	4.84	4.90	4.96	5.02	5.08	5.14
29	Estimated Heat Content - Btu/lb		11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500	11,500
30	Average Actual Cost of Coal - $/Ton		100.65	102.00	103.57	105.17	106.76	108.32	109.87	111.37	112.78	114.17	115.56	116.91	118.25
31	Cost of Coal for Generation		6,576,878	7,018,061	7,362,240	7,691,414	7,807,232	7,921,356	8,034,724	8,144,810	8,247,798	8,349,516	8,450,633	8,549,323	8,647,495

Table 11-6 (Continued)
Income Valuation of Electric Generation - High Fuel Market

Line No.	Description	Variables	Projected 2022 $	2023 $	2024 $	2025 $	2026 $	2027 $	2028 $	2029 $	2030 $	2031 $	2032 $	2033 $	2034 $
32	Forecast Minimum Load Heat Rate - BTU/kWh		18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
33	Cost of Coal at Minimum Load Generation		285,233	160,466	77,166	-	-	-	-	-	-	-	-	-	-
34	Non-Fuel O&M														
35	Variable O&M (Estimated at $1.25/MWh)		174,000	188,000	199,000	210,000	215,000	221,000	226,000	232,000	238,000	244,000	250,000	256,000	262,000
36	Fixed O&M														
37	Operating Steam Expense		217,000	222,000	228,000	234,000	240,000	246,000	252,000	258,000	264,000	271,000	278,000	285,000	292,000
38	Operating Electric Expense		345,000	354,000	363,000	372,000	381,000	391,000	401,000	411,000	421,000	432,000	443,000	454,000	465,000
39	Production Steam Maintenance		161,000	165,000	169,000	173,000	177,000	181,000	186,000	191,000	196,000	201,000	206,000	211,000	216,000
40	Other Fixed O&M		138,000	141,000	145,000	149,000	153,000	157,000	161,000	165,000	169,000	173,000	177,000	181,000	186,000
41	Total Non-Fuel O&M		1,035,000	1,070,000	1,104,000	1,138,000	1,166,000	1,196,000	1,226,000	1,257,000	1,288,000	1,321,000	1,354,000	1,387,000	1,421,000
42	Pollution Allowance Costs														
43	SO2		-	-	-	-	-	-	-	-	-	-	-	-	-
44	NOx		-	-	-	-	-	-	-	-	-	-	-	-	-
45	Total Pollution Alllowance Costs		-	-	-	-	-	-	-	-	-	-	-	-	-
46	Adminstrative and General Expenses														
47	A&G Salaries		131,000	134,000	137,000	140,000	144,000	148,000	152,000	156,000	160,000	164,000	168,000	172,000	176,000
48	Social Security Expense		64,000	66,000	68,000	70,000	72,000	74,000	76,000	78,000	80,000	82,000	84,000	86,000	88,000
49	Employee Benefits		345,000	354,000	363,000	372,000	381,000	391,000	401,000	411,000	421,000	432,000	443,000	454,000	465,000
50	Utilities Expense		386,000	396,000	406,000	416,000	426,000	437,000	448,000	459,000	470,000	482,000	494,000	506,000	519,000
51	Property Insurance		141,000	145,000	149,000	153,000	157,000	161,000	165,000	169,000	173,000	177,000	181,000	186,000	191,000
52	Other A&G Expenses		115,000	118,000	121,000	124,000	127,000	130,000	133,000	136,000	139,000	142,000	146,000	150,000	154,000
53	Total A&G		1,182,000	1,213,000	1,244,000	1,275,000	1,307,000	1,341,000	1,375,000	1,409,000	1,443,000	1,479,000	1,516,000	1,554,000	1,593,000
54	Capital Expenditures		-	-	-	-	-	-	-	-	-	-	-	-	-
55	Renewals and Replacements		200,000	200,000	200,000	200,000	200,000	200,000	200,000	200,000	-	-	-	-	-
56	Projected Cash Outflows		9,279,111	9,661,527	9,987,406	10,304,414	10,480,232	10,658,356	10,835,724	11,010,810	10,978,798	11,149,516	11,320,633	11,490,323	11,661,495
57	Margin at Full Load		1,380,026	1,511,347	1,680,470	1,842,626	1,970,408	2,108,004	2,250,996	2,408,870	2,554,122	2,714,564	2,881,407	3,050,677	3,220,465
58	Margin at Minimum Load		(194,708)	(110,209)	(53,366)	-	-	-	-	-	-	-	-	-	-
59	Net Margin (If negative, assume not operated)		1,185,317	1,401,137	1,627,104	1,842,626	1,970,408	2,108,004	2,250,996	2,408,870	2,554,122	2,714,564	2,881,407	3,050,677	3,220,465
60	Projected Net Cash Flow		(752,443)	(590,642)	(417,395)	(254,286)	(173,601)	(86,780)	5,768	112,536	407,029	513,069	624,874	738,481	850,989
61	*Discounted Cash Flow Value*														
62	Net Present Value (2010 - 2034)														
63	Future Salvage Value														
64	Present Value of Future Salvage														
65	Total Net Present Value														

12.0 References

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Appendix A
Boiler Inspection Report – Locke Equipment

LOCKE

Locke Equipment
Sales Co., Inc.
1917 E. Spruce
Olathe, KS 66062
913 782 8500
tim@lockeequipment.com

KESTEK
12503 Ensley Lane
Leawood, KS 66209
(816)392-9470
scott@kestek.com

Evaluation of Riley Boiler
City of Jasper, Indiana

for

Black & Veatch

Laboratory Control Number: 209031A

by Tim Locke, P.E. & Scott Kessler, Ph.D, P.E., ASNT Level III

December 18, 2009

Evaluation of Riley Boiler

City of Jasper, Indiana

Introduction

The following boiler condition assessment addresses the general condition of the Riley boiler located in Jasper, Indiana (Figure 1, Figure 2). The report specifically covers the condition of the internal tubing and headers at the current time.

As part of the assessment, previous records of repairs and prior boiler studies were reviewed. A summary of the previous history is provided below (Table 1). Other issues may have occurred, but were not in reported in the information supplied.

Both of the previous boiler study reports were reviewed. The first, by Hartford Steam Boiler was performed in early 1990. Some of its conclusions no longer apply as tubing has been replaced subsequently, but their general conclusions suggest that the boiler had not experienced any significant overheating or other damage. They did note "excessive internal deposits" in some instances which appears to have been largely remedied since that time. The more recent report prepared by Coastal Inspection Services in May of 2003 also did not uncover any evidence of high temperature excursions leading to damage, though only one waterwall tube was examined metallurgically. They also noted some internal scale build-up, but their main concern regarded excessive amounts of slag in the furnace. They also report wall loss in the generating bank tubing, but not greater than code would permit.

TABLE 1. Boiler repair and assessment history (based on the provided R-1's)

Date	Issue
6/7/2008	mag particle test steam header; repair 3 indications
7/7/2008	plugged economizer tube 23 from south
8/11/2006	plugged 5 economizer tubes
6/15/2009	plugged welds economizer header
11/11/2004	pad welded 6 economizer return bends
5/18/2004	pad weld sidewall tube
5/7/2004	weld metal build up 34 tubes 4' tall rear wall; apparently later replaced 4 foot sections of rear wall tubes
12/18/2003	plugged tube 21&23 in row 9 and tube21 in row 10
9/10/2003	repair pin holes in rear wall tubes
5/15/2003	pad weld 11 economizer sections; dutchman replaced side wall
4/14/2003	*Boiler Condition Assessment Survey by Coastal Inspection*
3/7/2003	pad weld N.E. corner 7' from bottom; plugged 1 gen bank tube south end
11/4/1999	pad weld, install dutchman for sample, plugged 1 tube
11/6/1998	plugged 6 gen bank tubes seal weld 23 tubes
1/14/1997	superheater tube plugged
7/18/1994	pad weld generating bank, plug gen bank tube
12/31/1992	pad weld rear wall tube; replace 48" right side obs port tube; buck stay section replaced
8/28/1992	SA 178a tube materials; SA 213 T22 tube materials
8/22/1992	data report 27 secondary superheater; 27 primary superheater; 36 economizer tubes.
1/?/1990	*Boiler Condition & Useful Life Study by Hartford Steam Boiler*

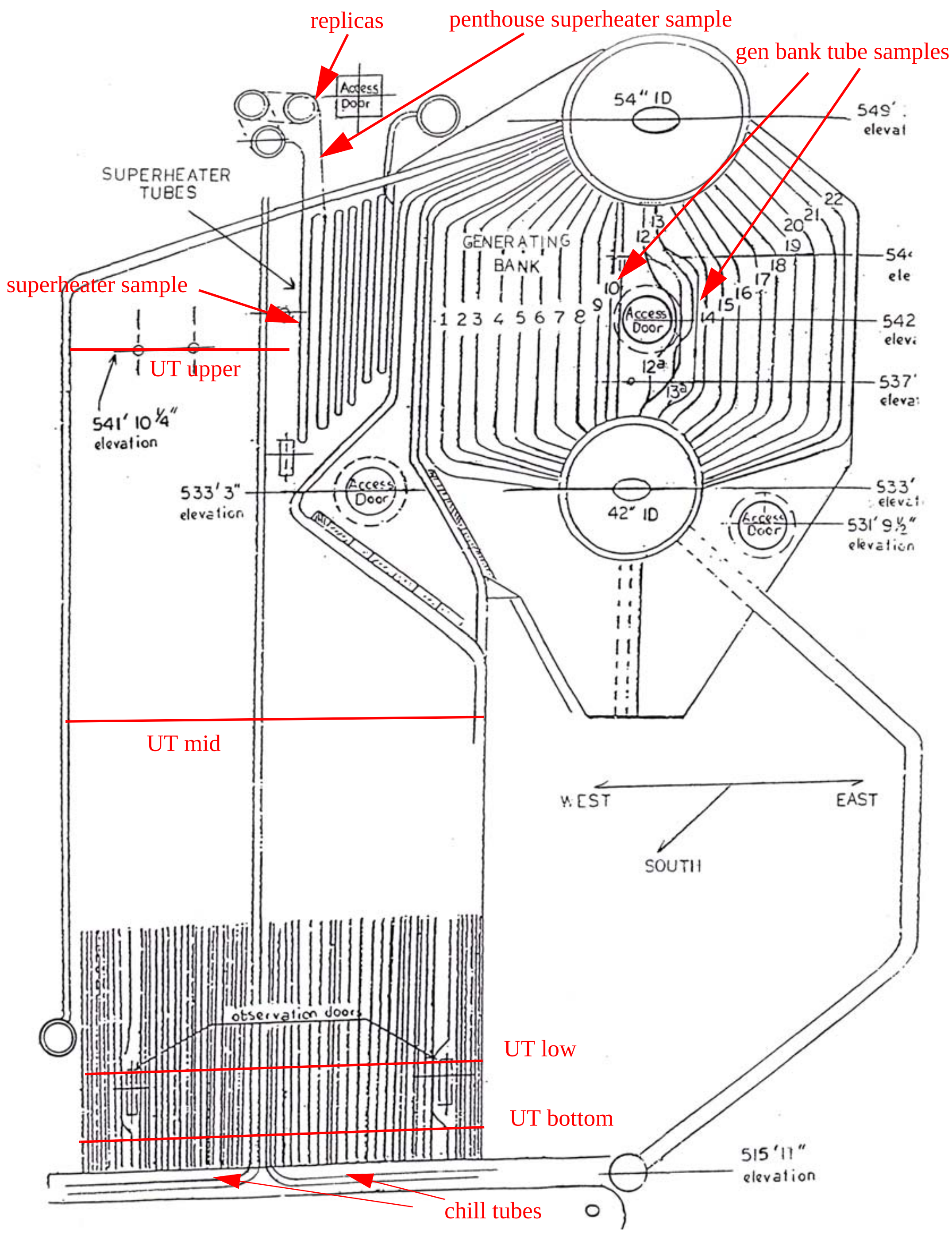

FIGURE 1. Sketch of the Riley boiler examined showing approximately locations of tube samples removed and testing performed.

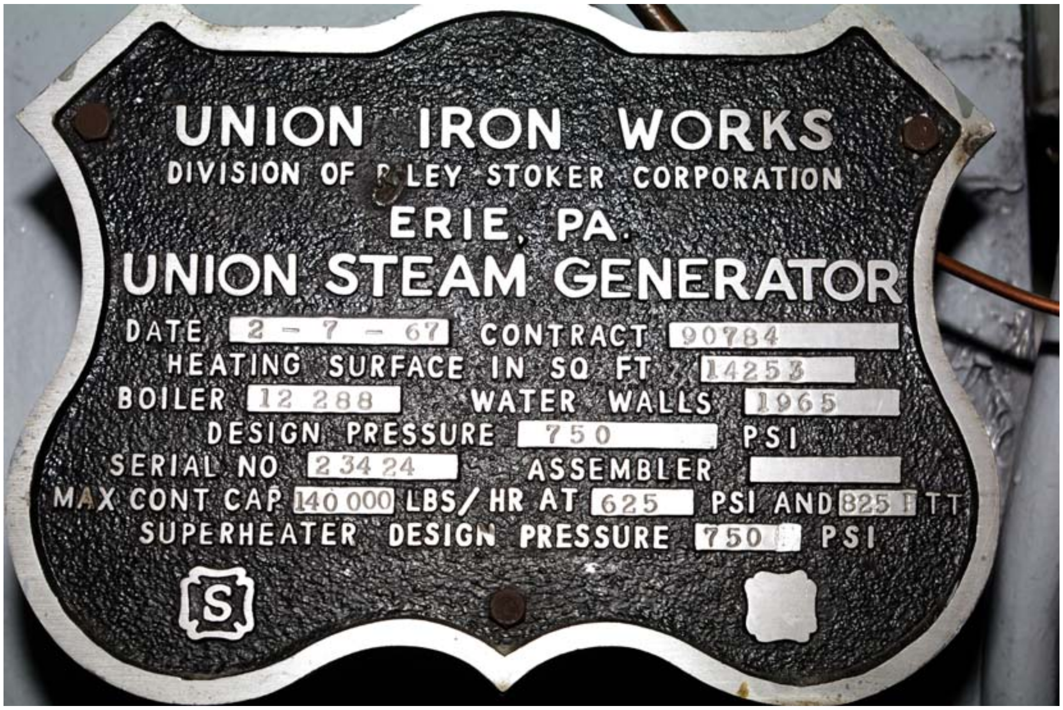

FIGURE 2. Boiler name plate.

Procedure

Initially, the boiler was inspected in a cursory manner to determine overall layout and discover if any obvious areas of concern existed. Based on experience and the visual examination areas were selected for further evaluation.

Ultrasonic thickness measurements were made at four levels inside the furnace on the waterwall tubing (. The chill tubes were also checked at a few locations. Additionally, the superheater pendants closest to the fire side were measured for thickness.

Based on the thickness measurements and the visual condition of the tubing, several destructive samples were removed for metallurgical evaluation including microhardness testing. Metallurgical replicas were made of the outlet header in two locations. The steam deposit accumulation (scale build-up) was also determined;

Results

Visual Examination

The exterior of the boiler appears to be in very good to excellent condition (Figure 3, Figure 4). The only external area of concern noted was at that top of unit a couple of barrels were in-place, apparently to trap water leaking from the roof (Figure 5).

For the most part the lower areas of the furnace appear to be in fair to good condition (Figure 6, Figure 7). The grating shows evidence of wear producing gaps that should be repaired to prevent uneven air flow (Figure 8). There are several areas where tubing has been repaired by either pad welding or windows (Figure 9, Figure 10). The repair welding is of fair quality, but the windows are square when a rounded design should have been utilized. The inspection port tubes are in good condition without obvious signs of wear (Figure 11). The areas further up the wall around the burners are also in fair condition (Figure 12, Figure 13). The nose of the rear wall has significant slag build-up (Figure 14).

The superheater pendants are free hanging (no spacing brackets or handcuffs) and do not have even spacing between adjacent pendants (Figure 15). The superheats also have significant amounts of slag present and in some cases, due to the lack of proper spacing, have become welded together by the slag (Figure 16, Figure 17, Figure 18).

The steam drum and its internals are in good condition (Figure 19, Figure 20). The tubing, when viewed from the steam drum has some scale present, but no excessive in nature (Figure 21, Figure 22). There are several tubes that have been plugged (Figure 23).

The generating bank has significant amounts of slag present and again have some issues with alignment preventing proper air flow (Figure 24, Figure 25). There are also several failed tubes (plugged at the drums) have been left in-place (Figure 26).

The mud drum also appears to be in good condition. The tubing, though plugged in some instances, does not exhibit excessive scaling or other damage as viewed from inside the drum (Figure 27, Figure 28, Figure 29).

When view from the penthouse, the headers, for the most part, appear to be in fair to good condition (Figure 30, Figure 31). There is a tube to header repair weld that is of questionable quality (Figure 32).

The economizer also has significant amounts of external scaling, particularly at the lower level (Figure 33, Figure 34). The middle section of the economizer also shows evidence of blockage (Figure 35, Figure 36).

Based on the visual inspection and experience, further nondestructive testing (e.g., magnetic particle testing, penetrant testing, etc.) was not deemed necessary.

Ultrasonic Thickness Measurements

Ultrasonic thickness measurements were made in several locations on the waterwall tubing (Figure 37, Table 2), the generating bank tubing (Table 3), the superheater pendants (Table 4), the chill tubes (Table 5), and the economizer tubing (Table 6, Table 7). The ultrasonic meter used was calibrated on standards prior to use and the tube samples removed subsequently were also checked for verification of calibration by direct measurement.

In general the wall thicknesses were found to be normal with the following comments:

- the waterwall tubing appears to thin as the elevation increases
- the generating bank tubing appears to have thinned in several locations (most of the generating bank is not accessible to UT thickness measurements from the outside diameter and the remote field eddy study carried out by Coastal Inspection suggests that a some tubes have thinned to some degree, though not a great number)
- the superheater pendants (only the outer tubes are accessible) have reasonable thickness
- the chill tubes appear to be in reasonable condition with regards to thickness
- the economizer bends have thinned considerably, particularly towards the bottom section

FIGURE 3. View of the unit from the coal feeder end.

FIGURE 4. Outside view of steam drum and penthouse entrance.

FIGURE 5. Roof of boiler with catch barrels in-place.

FIGURE 6. Right side wall of the furnace.

FIGURE 7. Front wall of the furnace showing spreader paddles.

FIGURE 8. Grating evidences link wear producing gaps.

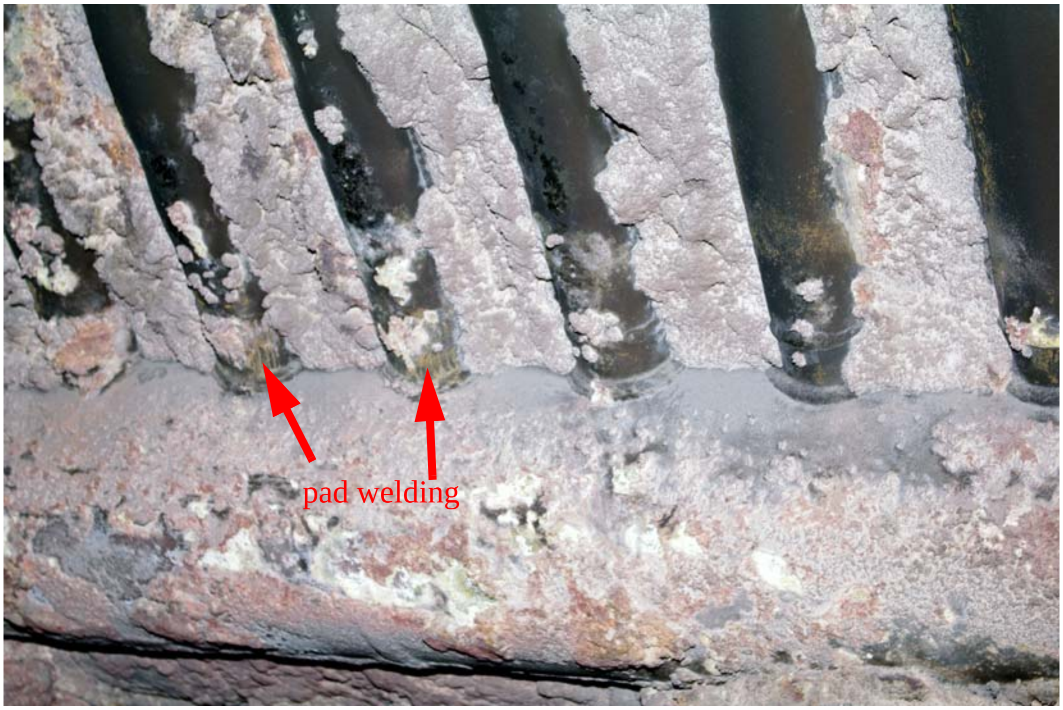

FIGURE 9. Front wall header connection with evidence of pad weld repairs.

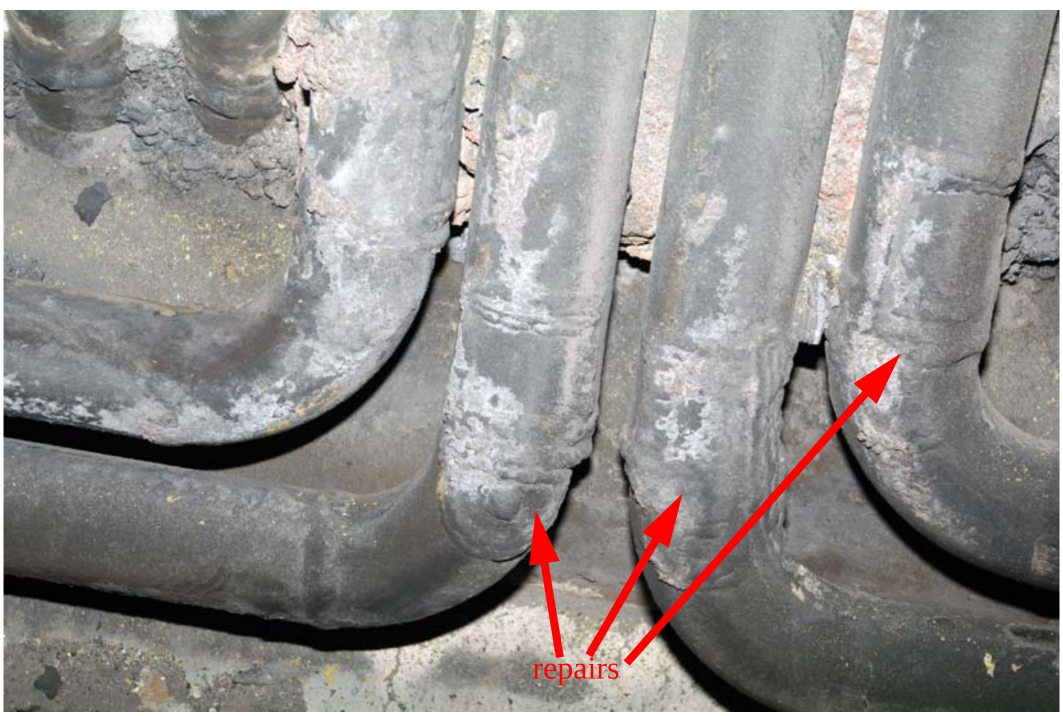

FIGURE 10. Chill tubes showing repaired areas.

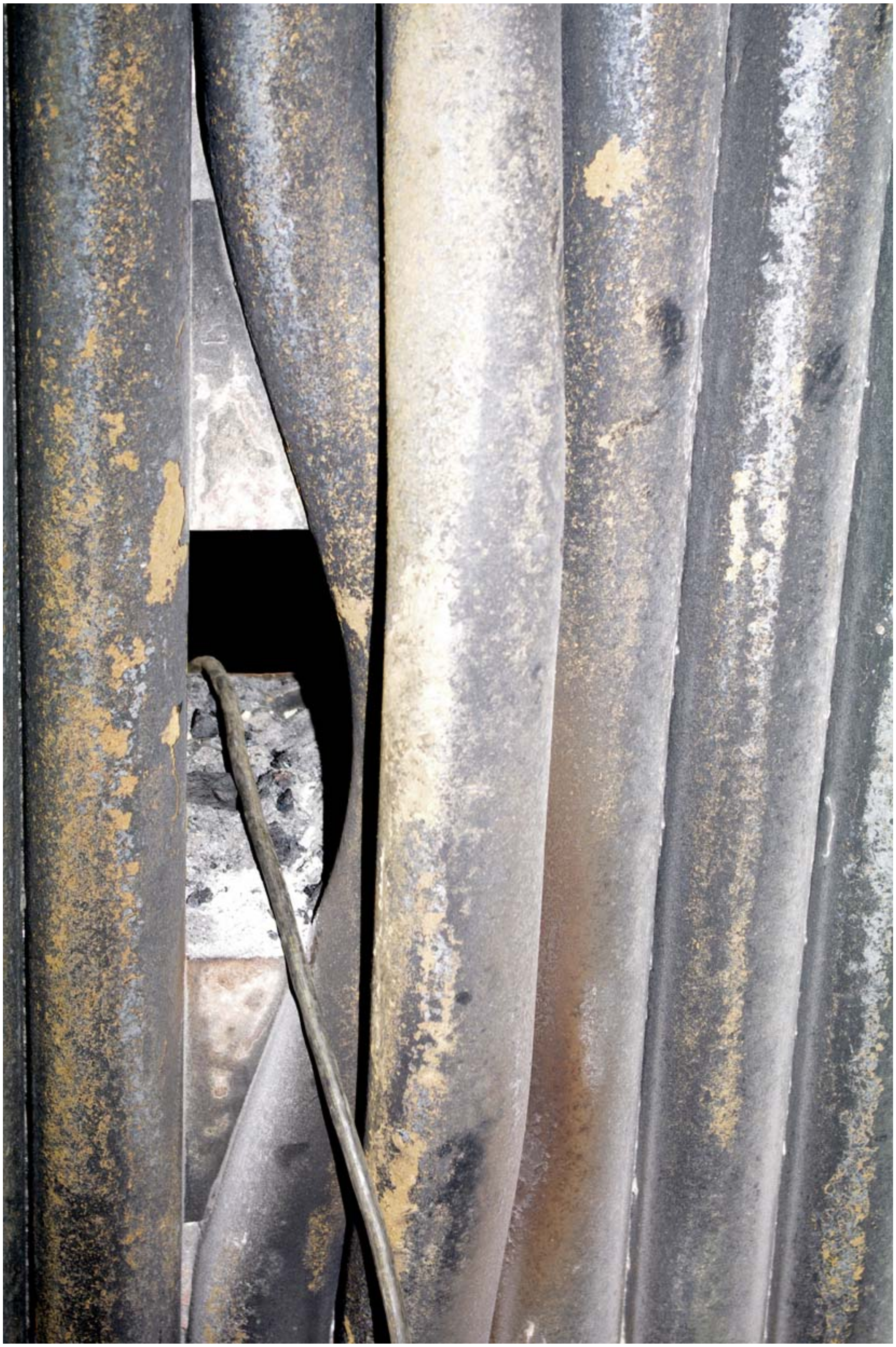

FIGURE 11. Inspection port tubing appears to be in good condition.

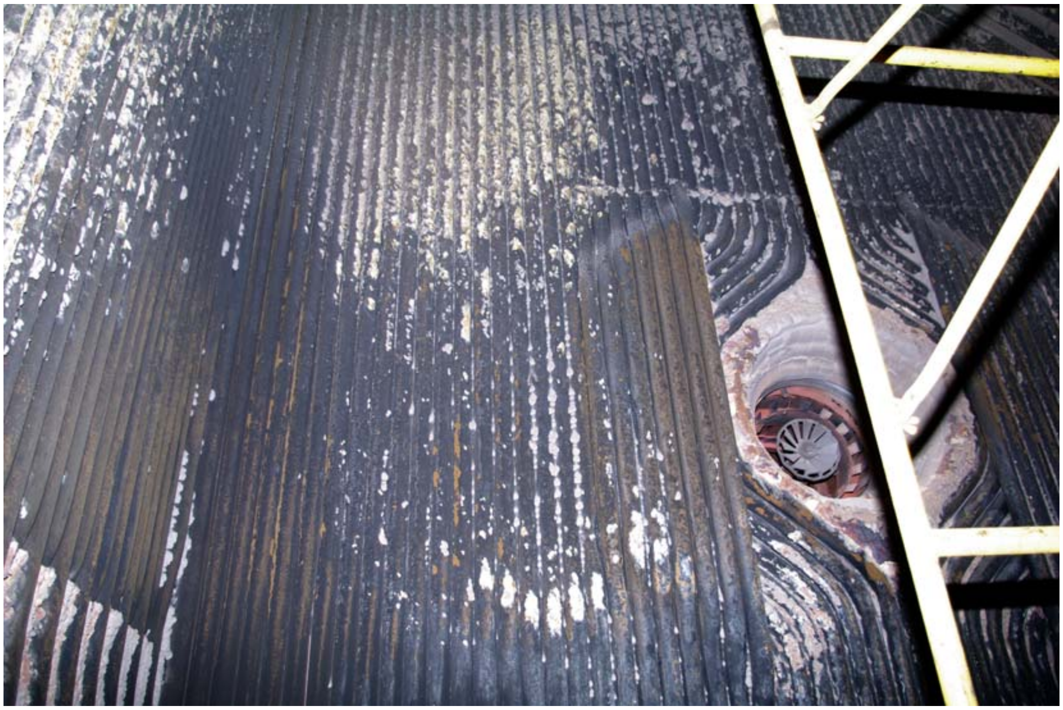
FIGURE 12. Left side of the furnace.


FIGURE 13. View of the gas burner.

FIGURE 14. Rear wall at nose, note slag build-up.

FIGURE 15. Superheater pendant showing loose alignment.

FIGURE 16. Superheater tubing from the furnace (center discolored tubes from leakage above during tubing removal in penthouse.

FIGURE 17. Another view of the superheater pendants, note lack of separation.

FIGURE 18. Close-up of superheater pendants, note area prepped for UT thickness measurement.

FIGURE 19. Steam drum internals.

FIGURE 20. Steam drum internals in the opposite direction.

FIGURE 21. Steam drum tubes.

FIGURE 22. Representative tube as seen from the steam drum.

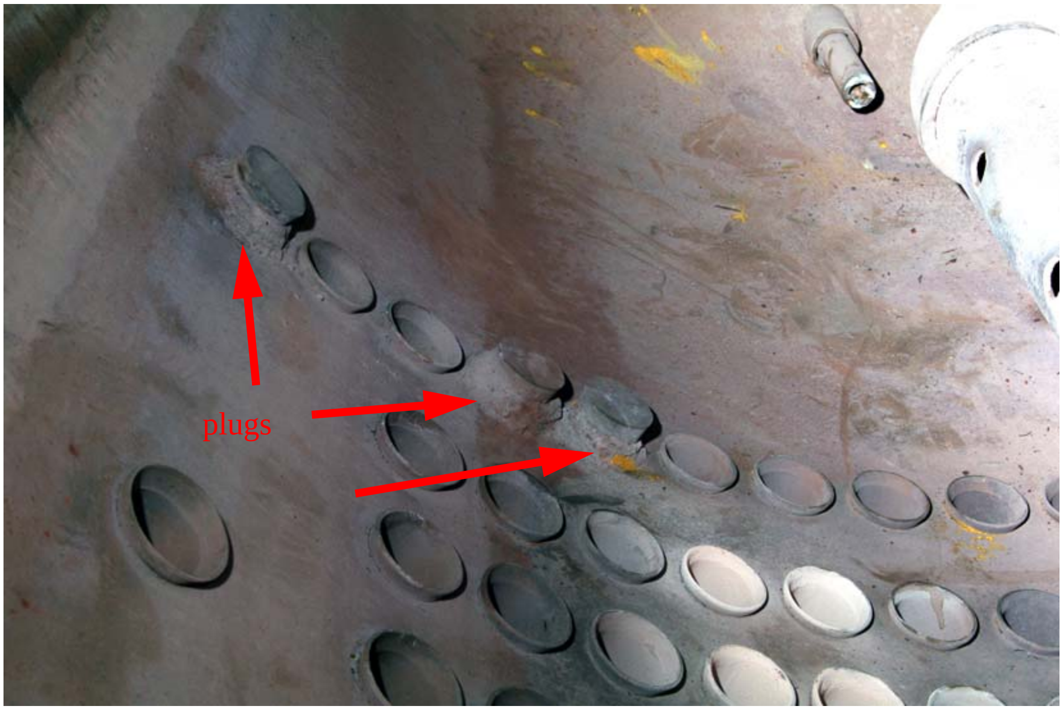

FIGURE 23. Steam plugged tubes.

FIGURE 24. Generating bank tubing.

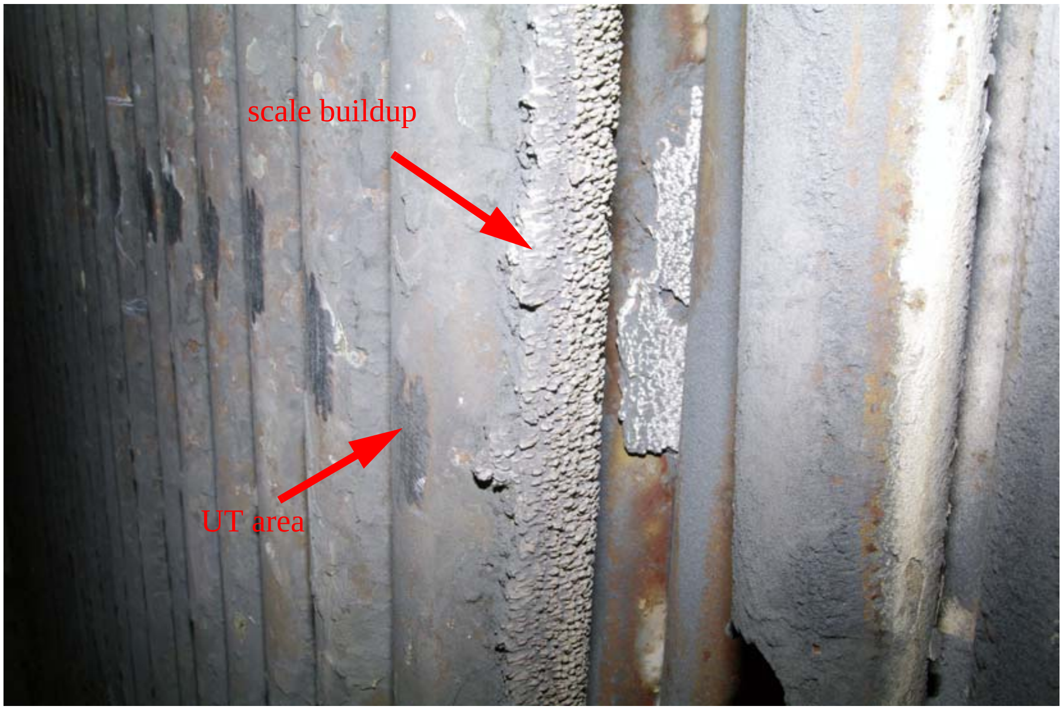

FIGURE 25. West side generating bank tubing showing excessive scale build-up (also note UT thickness prepped areas.

FIGURE 26. Generating bank tube failures.

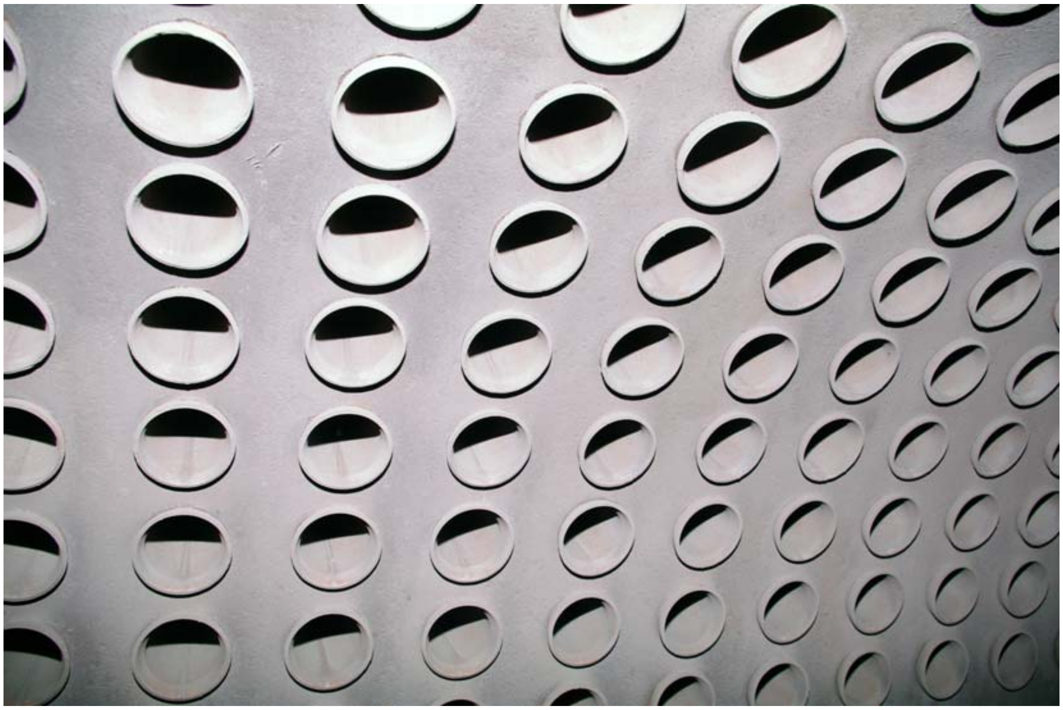

FIGURE 27. Tubing as seen from inside the mud drum.

FIGURE 28. Mud drum plugged tubes.

FIGURE 29. Representative tube as seen from the mud drum.

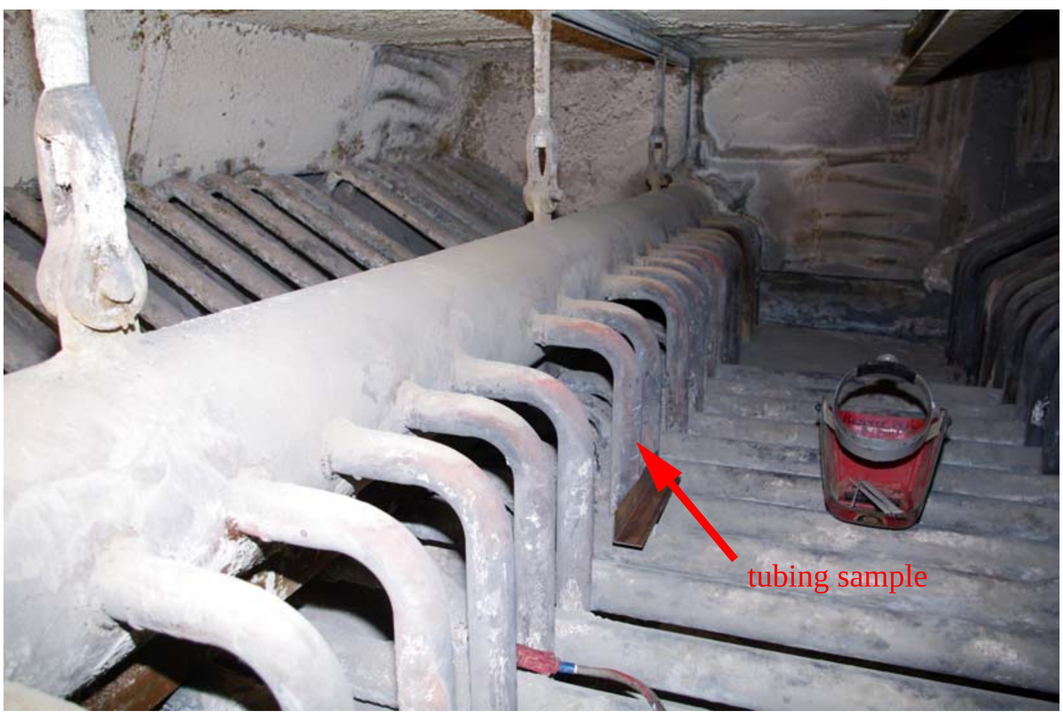

FIGURE 30. Rearward view from the penthouse, also showing tube sample location.

FIGURE 31. View inside the penthouse facing towards the front.

FIGURE 32. Header to tube repair.

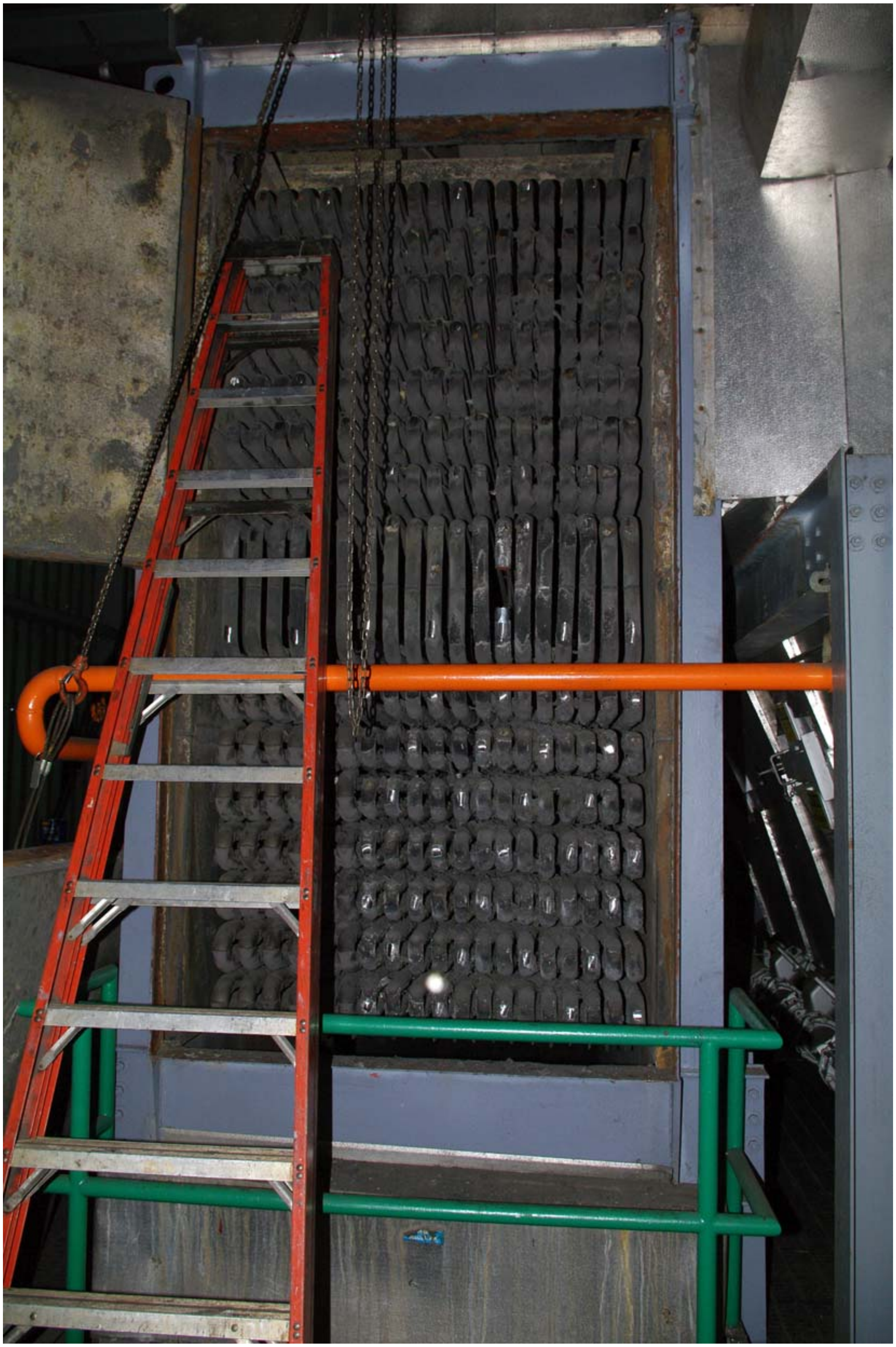

FIGURE 33. Side view of the economizer, note random UT thickness locations.

FIGURE 34. Close-up of economizer loops with significant blockage between tubes.

FIGURE 35. View from inside the middle section of the economizer.


FIGURE 36. Another view inside the economizer.

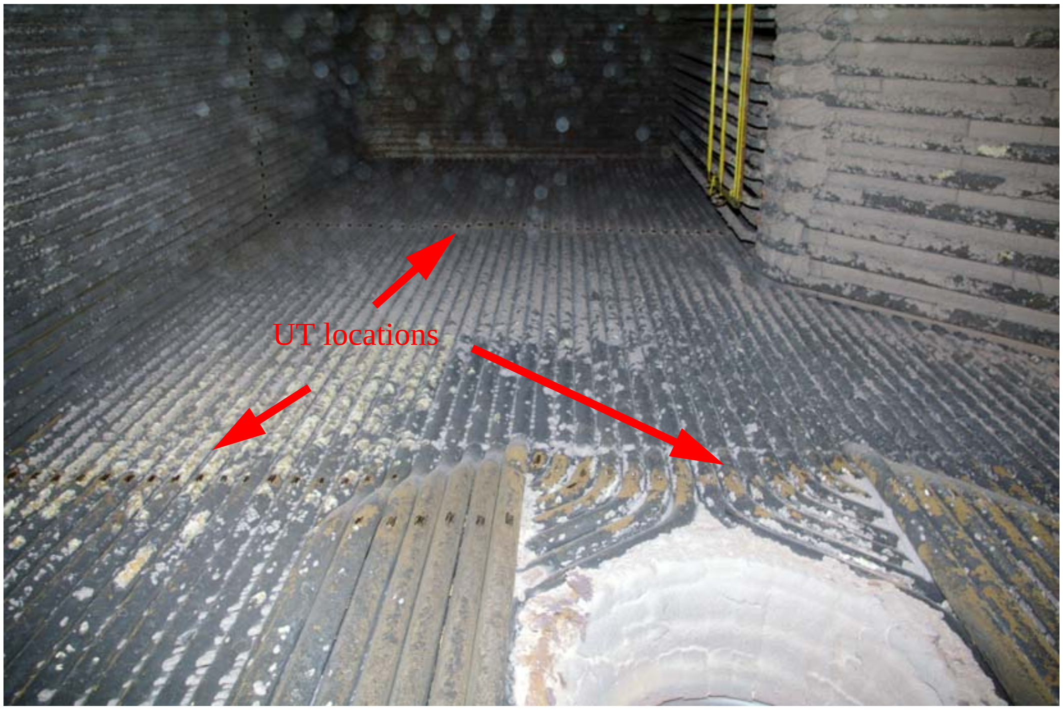

FIGURE 37. View showing side wall locations for UT thickness measurement at the upper elevations (upper and mid).

TABLE 2. Waterwall UT thickness measurements (in).

Tube #	Left Wall Upper	Left Wall Mid	Left Wall Low	Left Wall Bottom	Rear Wall Low	Rear Wall Bottom	Right Wall Upper	Right Wall Mid	Right Wall Low	Right Wall Bottom	Front Wall Mid	Front Wall Low	Front Wall Bottom
1	0.112	0.155	0.143	0.143	0.140	0.200	0.104	0.109	0.138	0.137	0.104	0.101	0.124
2	0.112	0.128	0.144	0.141	0.139	na	0.106	0.109	0.143	0.134	0.104	0.116	na
3	0.120	0.123	0.144	0.137	0.140	0.220	0.106	0.116	0.142	0.139	0.109	0.107	0.128
4	0.113	0.129	0.141	0.145	0.137	na	0.107	0.114	0.144	0.148	0.108	0.100	na
5	0.110	0.131	0.143	0.144	0.141	0.217	0.108	0.112	0.144	0.141	0.111	0.095	0.128
6	0.110	0.130	0.142	0.150	0.141	na	0.108	0.108	0.139	0.149	0.108	0.102	na
7	0.118	0.126	0.137	0.145	0.138	0.207	0.109	0.108	0.144	0.140	0.108	0.128	0.121
8	0.109	0.124	0.143	0.146	0.139	na	0.109	0.108	0.143	0.140	0.108	0.128	na
9	0.112	0.124	0.147	0.148	0.144	0.195	0.108	0.110	0.144	0.140	0.110	0.129	0.133
10	0.112	0.125	0.140	0.139	0.142	na	0.108	0.110	0.148	0.141	0.102	0.158	na
11	0.110	0.127	0.146	0.146	0.146	0.196	0.110	0.108	0.144	0.143	0.104	0.142	0.087
12	0.112	0.128	0.146	0.145	0.135	na	0.113	0.129	0.145	0.143	0.106	0.124	na
13	0.108	0.128	0.145	0.141	0.131	0.192	0.111	0.108	0.146	0.143	0.111	0.124	0.121
14	0.109	0.130	0.144	0.142	0.134	na	0.110	0.118	0.147	0.134	0.106	0.128	na
15	0.109	0.130	0.143	0.143	0.135	0.197	0.114	0.111	0.146	0.135	0.112	0.125	0.126
16	0.114	0.127	0.146	0.143	0.133	na	0.114	0.111	0.145	0.135	0.110	0.137	na
17	0.112	0.126	0.140	0.136	0.139	0.185	0.120	0.108	0.145	0.129	0.104	0.131	0.128
18	0.109	0.131	0.140	0.143	0.137	na	0.112	0.125	0.146	0.129	0.127	0.137	na
19	0.107	0.129	0.139	0.139	0.138	0.198	0.110	0.130	0.142	0.141	0.125	0.124	0.130
20	0.111	0.162	0.140	0.139	0.137	na	0.110	0.110	0.151	0.139	0.134	0.126	na
21	0.110	0.171	0.141	0.148	0.138	0.176	0.110	0.109	0.149	0.144	0.127	0.137	0.128
22	0.111	0.182	0.141	0.155	0.137	na	0.110	0.112	0.149	0.149	0.126	0.126	na

TABLE 2. Waterwall UT thickness measurements (in). (continued)

Tube #	Left Wall Upper	Left Wall Mid	Left Wall Low	Left Wall Bottom	Rear Wall Low	Rear Wall Bottom	Right Wall Upper	Right Wall Mid	Right Wall Low	Right Wall Bottom	Front Wall Mid	Front Wall Low	Front Wall Bottom
23	0.112	0.162	0.139	0.143	0.135	0.180	0.104	0.139	0.149	0.140	0.124	0.129	0.134
24	0.112	0.162	0.139	0.143	0.137	na	0.110	0.114	0.149	0.141	0.129	0.126	na
25	0.112	0.164	0.139	0.142	0.138	0.174	0.108	0.121	0.146	0.139	0.129	0.128	0.126
26	0.118	0.160	0.138	0.146	0.133	na	0.112	0.110	0.148	0.151	0.126	0.129	na
27	0.117	0.163	0.146	0.142	0.132	0.183	0.104	0.111	0.146	0.141	0.121	0.131	0.125
28	0.114	0.157	0.142	0.131	0.146	na	0.105	0.110	0.148	0.148	0.130	0.124	na
29	0.113	0.163	0.146	0.155	0.137	0.183	0.106	0.110	0.143	0.146	0.133	0.130	0.131
30	0.113	0.160	0.140	0.140	0.143	na	0.107	0.111	0.147	0.134	0.131	0.124	na
31	0.112	0.161	0.146	0.139	0.142	0.194	0.128	0.116	0.146	0.136	0.126	0.126	0.119
32	0.118	0.164	0.138	0.170	0.139	na	0.111	0.110	0.149	0.170	0.122	0.134	na
33	0.108	0.163	0.140	0.165	0.137	0.189	0.109	0.112	0.145	0.168	0.124	0.139	0.126
34	0.112	0.162	0.139	0.166	0.139	0.194	0.108	0.110	0.145	0.161	0.122	0.126	0.155
35	0.111	0.162	0.143	0.164	0.139	na	0.106	0.111	0.146	0.164	0.128	0.126	na
36	0.111	0.157	0.143	0.135	0.148	0.188	0.105	0.108	0.153	0.130	0.124	0.124	0.131
37	0.106	0.179	0.136	0.146	0.145	na	0.105	0.110	0.147	0.131	0.130	0.125	na
38	0.115	0.162	0.138	0.140	0.145	0.198	0.104	0.112	0.143	0.124	0.126	0.124	0.128
39	0.115	0.162	0.146	0.137	0.148	na	0.105	0.118	0.146	0.130	0.128	0.125	na
40	0.114	0.167	0.141	0.135	0.141	0.171	0.131	0.113	0.156	0.131	0.125	0.141	0.131
41	0.120	0.162	0.141	0.141	0.140	na	0.110	0.114	0.147	0.131	0.123	0.126	na
42	0.127	0.162	0.135	0.137	0.133	0.178	0.108	0.114	0.147	0.131	0.118	0.126	0.135
43	na	0.166	0.139	0.153	0.137	na	0.114	0.116	0.145	0.135	0.125	0.126	na
44	na	0.163	0.144	0.131	0.175	0.186	0.111	0.121	0.146	0.141	0.120	0.126	0.129
45	na	0.161	0.143	0.131	0.146	na	na	0.116	0.146	0.137	0.118	0.126	na
46	na	0.159	0.142	0.143	0.139	0.199	na	0.115	0.148	0.131	0.118	0.124	0.122
47	na	0.158	0.144	0.136	0.137	na	na	0.114	0.147	0.136	0.127	0.122	na
48	na	0.122	0.141	0.130	0.141	0.208	na	0.113	0.143	0.141	0.119	0.122	0.127
49	na	0.126	0.143	0.139	0.141	na	na	0.113	0.147	0.137	0.121	0.122	na
50	na	0.125	0.137	0.137	0.141	0.104	na	0.112	0.140	0.139	0.119	0.123	0.128
51	na	0.130	0.143	0.136	0.145	na	na	0.120	0.143	0.138	0.121	0.123	na
52	na	0.122	0.143	0.143	0.141	0.187	na	0.114	0.143	0.141	0.120	0.127	0.132
53	na	0.143	0.141	0.142	0.143	na	na	na	0.148	0.144	0.129	0.126	na
54	na	na	0.143	0.161	0.148	0.202	na	na	0.146	0.148	0.116	0.123	0.123
55	na	na	0.141	0.142	0.142	na	na	na	0.144	0.140	0.120	0.132	na
56	na	na	0.142	0.145	0.148	0.184	na	na	0.143	0.144	0.116	0.125	0.124
57	na	na	0.141	0.140	0.147	na	na	na	0.142	0.147	0.118	0.126	na
58	na	na	0.139	0.143	0.138	0.189	na	na	0.143	0.143	0.114	0.125	0.128
59	na	na	0.142	0.142	0.139	na	na	na	0.141	0.144	na	0.126	na
60	na	na	0.139	0.141	0.142	0.180	na	na	0.143	0.147	na	0.123	na
61	na	na	0.138	0.146	0.136	na	na	na	0.146	0.139	na	0.125	na
62	na	na	0.141	0.144	0.135	0.208	na	na	0.146	0.141	na	0.125	na
63	na	na	0.143	0.141	0.134	na	na	na	0.143	0.148	na	0.126	na
64	na	na	0.142	0.145	0.139	0.191	na	na	0.144	0.144	na	0.127	na
65	na	na	0.136	0.142	0.135	na	na	na	0.141	0.148	na	0.150	na
66	na	na	na	na	0.136	0.188					0.125	0.127	na

TABLE 3. Generating bank UT thickness (in).

Tube #	West Wall	East Wall	Tube #	West Wall	East Wall
1	OBSTR	0.108	30	OBSTR	0.095
2	0.112	0.104	31	0.109	0.095
3	0.115	0.113	32	0.108	0.084
4	0.116	0.106	33	0.112	0.081
5	0.116	0.108	34	0.106	0.084
6	0.116	0.110	35	0.107	0.111
7	0.115	0.108	36	0.107	0.112
8	0.117	0.107	37	0.105	0.104
9	0.115	0.108	38	0.105	0.110
10	0.118	0.113	39	0.104	0.108
11	0.113	0.108	40	0.104	0.105
12	0.114	0.110	41	0.108	0.107
13	0.122	0.111	42	0.116	0.117
14	0.114	0.112	43	0.104	0.105
15	0.108	0.108	44	0.104	0.109
16	0.107	0.107	45	0.110	0.102
17	0.106	0.109	46	0.108	0.106
18	0.109	0.108	47	0.114	0.106
19	0.110	0.108	48	0.114	0.117
20	0.108	0.109	49	0.105	0.110
21	0.113	0.108	50	0.101	0.110
22	0.105	0.110	51	0.107	0.104
23	0.105	0.105	52	0.107	0.112
24	0.113	0.109	53	0.100	0.110
25	0.104	0.083	54	0.108	0.106
26	0.106	0.086	55	0.106	0.083
27	0.107	0.083	56	0.105	0.078
28	OBSTR	0.083	57	0.113	0.110
29	OBSTR	0.085			
30	OBSTR	0.095			

TABLE 4. Superheater tubing thickness (in).

Tube #	Superheater Thickness	Tube #	Superheater Thickness	Tube #	Superheater Thickness
1	0.152	14	0.145	27	0.147
2	0.149	15	0.144	28	0.152
3	0.170	16	0.143	29	0.147
4	0.147	17	0.149		
5	0.147	18	0.153		
6	0.148	19	0.143		
7	0.141	20	0.149		
8	na	21	0.154		
9	na	22	0.159		
10	0.149	23	0.148		
11	0.148	24	0.148		
12	0.148	25	0.150		
13	0.150	26	0.149		

TABLE 5. Chill tube thickness measurements (in).

Tube #	North Side Chill Tube Thickness	South Side Chill Tube Thickness
1	0.214	0.224
2	0.227	0.205
3	0.209	0.240
4	0.226	0.209
5	0.212	0.207
6	0.209	0.212
7	0.226	0.215
8	0.220	0.216

TABLE 6. Economizer tube thickness measurements (in).

Loop #	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
1	na	0.145	na	na	0.146	na	na	0.151	na	na	0.150	na
2	0.151	na	na	0.150	na	na	0.149	na	na	0.143	na	na
3	na	na	0.166	na	na	0.150	na	na	0.142	na	na	0.155
4	na	0.130	na	na	0.144	na	na	0.147	na	na	0.145	na
5	0.149	na	na	0.145	na	na	0.144	na	na	0.147	na	na
6	na	na	0.146	na	na	0.144	na	na	0.147	na	na	0.143
7	na	0.081	na	na	0.142	na	na	0.146	na	na	0.149	0.149
8	0.171	0.158	na	0.166	0.168	na	0.168	0.152	na	0.171	0.142	na
9	na	na	na	na	na	na	0.154	na	na	0.134	na	na
10	na	na	na	na	na	na	na	na	0.136	na	na	0.126
11	na	na	na	na	na	na	na	0.133	na	na	0.120	na
12	na	na	na	na	na	na	0.130	na	na	0.126	na	na
13	na	na	na	na	na	na	0.134	na	0.122	na	na	0.129
14	na	na	na	na	na	na	na	0.106	na	na	0.117	na
15	na	na	na	na	na	na	0.067	na	0.074	na	na	0.079

TABLE 7. Economizer tube thickness measurements (in).

Loop #	Col 13	Col 14	Col 15	Col 16	Col 17	Col 18	Col 19
1	na	0.154	na	na	0.147	na	na
2	0.142	na	na	0.145	na	na	0.155
3	na	na	0.140	na	na	0.142	na
4	na	0.158	na	na	0.142	na	na
5	0.148	na	na	0.151	na	na	na
6	na	na	0.137	na	na	0.140	na
7	na	na	na	0.140	na	na	na
8	0.167	0.159	na	0.164	0.149	na	0.154
9	0.133	na	na	0.133	na	na	0.136
10	na	na	0.135	na	na	0.137	na
11	na	0.129	na	na	0.122	na	na
12	0.126	na	na	0.124	na	na	0.139
13	na	na	0.126	na	na	0.116	na
14	na	0.102	na	na	0.114	na	na
15	na	na	0.083	na	na	na	0.084

Metallurgical Evaluation

Representative tubing samples (Figure 38) were removed from the superheater pendant from in the furnace (Figure 39, Figure 40) and near the outlet header in the penthouse (Figure 41, Figure 42). Generating bank tube samples were taken in two locations; one from the west side (Figure 43, Figure 44) and the other from the east side (Figure 45, Figure 46) as accessed from the manway. A sample was also removed from the economizer along a straight section (Figure 47, Figure 48). A loop may have been preferable, but the straight was much easier to repair. Each of the tube samples was examined for damage and none was noted with the exception of the large amounts of outer scale on the superheater and west generating bank tubing. The tube wall thicknesses were also found to be within specification.

The following photomicrographs show the various microstructures noted for each of the removed tube samples. In each case, lower magnification (approximately 100X) micrographs of the outer and inner microstructures are shown followed by higher magnification views (approximately 400X) of the outer, core, and inner structures. In general, light or white areas are ferrite and dark lamellar areas are pearlite. A mixture of both would be considered normal for the materials involved. Additionally, the T22 material frequently will have some carbide particles distributed throughout which show up as dark and round nodules. If the pearlite is spheroidized (round shaped) then the material has seen some high temperature exposure with the amount of spheroidization dependent on the temperature and exposure time (this condition was not noted in the samples examined). The superheater tubing and header are also potentially subject to creep conditions which in the extreme produce grain boundary separation (again, the materials examined do not show evidence of creep).

Replicas were made at two locations on the outlet superheater pendant (labeled A and B, Figure 49, Figure 50). This location was chosen as it should see the highest temperatures of any of the headers. Based on the evaluation at this location the other headers were not examined by replication.

The microhardness results, deposit weight, and the microstructural results are summarized below (Table 8). For the most part the microstructures and hardnesses are normal for the material specified at the given location. The greatest concern is the buildup of scale or slag on the outer surfaces of the tubing. The inner scaling would be considered normal and at the thicknesses noted, the magnetite layer generally provides a protective coating. Guidelines have been developed for when chemical cleaning may be recommended. Generally levels below 15 g/ft^2 are considered clean, 15 to 40 g/ft^2 moderately dirty, and greater than 40 g/ft^2 very dirty.[1]

TABLE 8. Microhardness testing results, deposit weight, and microstructure.

Tube Sample	Inside Knoop (HRB)	Core Knoop (HRB)	Outside Knoop (HRB)	Deposit Weight g/ft^2	Microstructure Comments
superheater (furnace)	139 (69)	142 (71)	141 (71)	< detect-able	Assuming SA213-T22 material Basically normal: dispersion of carbide particles in a matrix of ferrite w/ some pearlite (Figure 51, Figure 52. Figure 53, Figure 54, Figure 55)
superheater (penthouse)	171 (82)	172 (83)	171 (82)	< detect-able	Assuming SA213-T22 material Basically normal: dispersion of carbide particles in a matrix of ferrite w/ some pearlite (Figure 56, Figure 57, Figure 58, Figure 59, Figure 60)

1. K.L. Atwood and C.L. Hale, "A Method for Determining Need for Chemical Cleaning of High Pressure Boilers," Presented at American Power Conference, April 1971.

TABLE 8. Microhardness testing results, deposit weight, and microstructure.

Tube Sample	Inside Knoop (HRB)	Core Knoop (HRB)	Outside Knoop (HRB)	Deposit Weight g/ft^2	Microstructure Comments
gen bank east	125 (63)	110 (53)	120 (60)	20.5	SA178A Normal: ferrite and pearlite (Figure 61, Figure 62, Figure 63, Figure 64, Figure 65)
gen bank west	120 (60)	116 (57)	132 (66)	4.8	SA178A Normal: ferrite and pearlite (Figure 66, Figure 67, Figure 68, Figure 69, Figure 70)
economizer	134 (67)	106 (49)	142 (71)	< detect-able	SA178A Normal: ferrite and pearlite (Figure 71, Figure 72, Figure 73, Figure 74, Figure 75)
2nd stage header	na	na	na	< detect-able	SA335A-P11 Normal; ferrite and pearlite Surface Hardness @ A BHN 143 = HRB 78 Surface Hardness @ B BHN 147 = HRB 79 (Figure 76, Figure 77)

FIGURE 38. Tubing samples after removal (top sample is superheater from furnace).

FIGURE 39. Close-up view of the superheater tube sample exterior (from furnace).

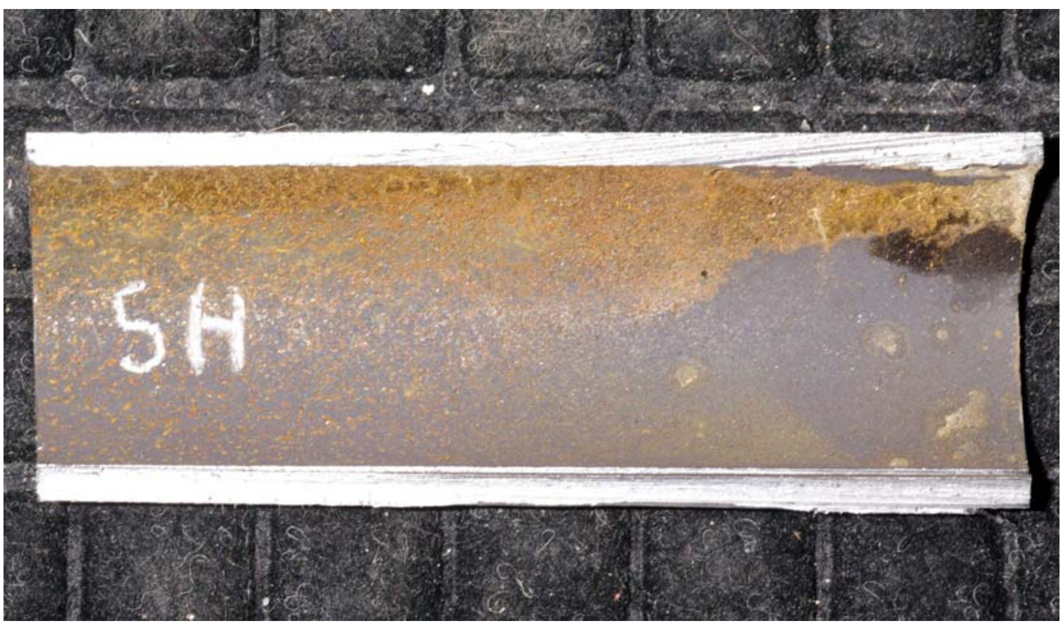

FIGURE 40. Superheater tube sample (from the furnace) interior.

FIGURE 41. Close-up view of the superheater tube sample exterior (removed from penthouse).

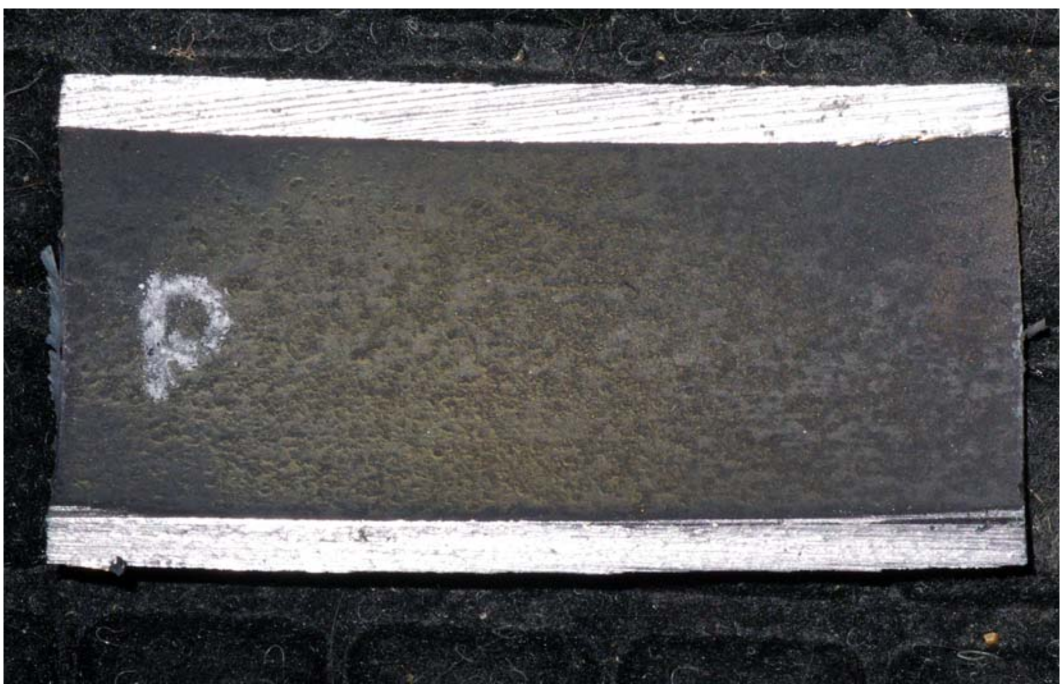

FIGURE 42. Superheater tube sample (from the penthouse) interior.

FIGURE 43. Generating bank tube sample from the east side.

FIGURE 44. East generating bank tube sample interior.

FIGURE 45. Generating bank tube sample from the west side.

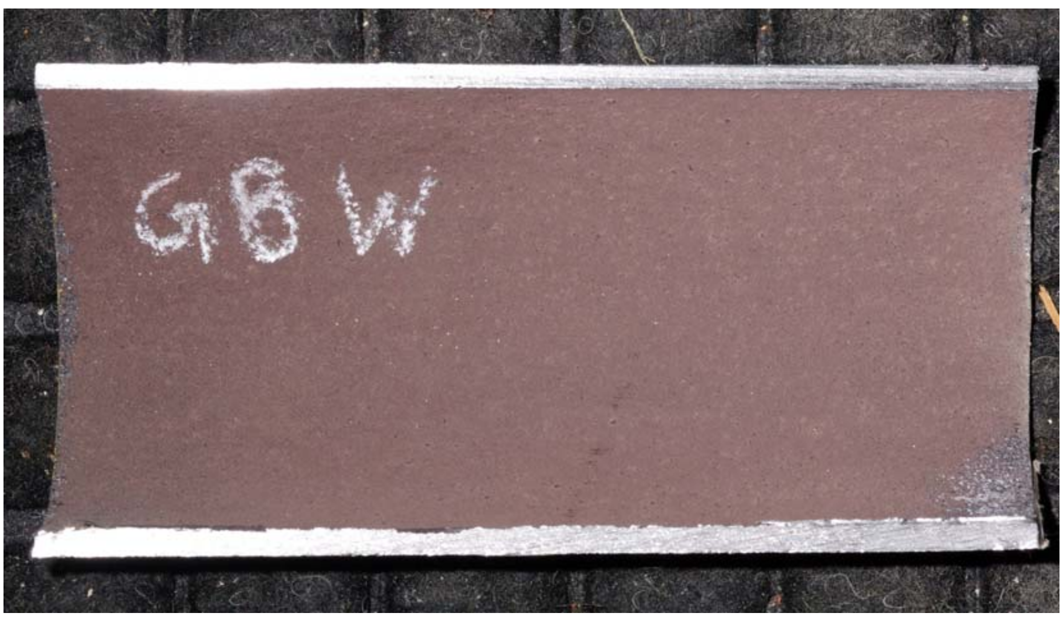

FIGURE 46. West generating bank tube sample interior.

FIGURE 47. Close-up of the economizer tube sample.

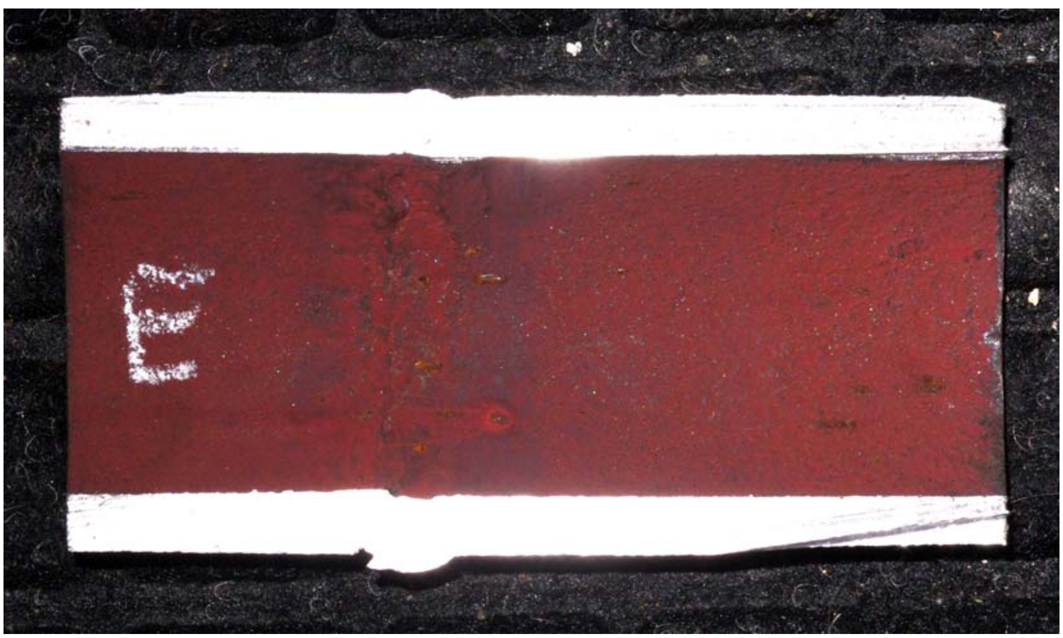

FIGURE 48. Economizer tube sample interior.

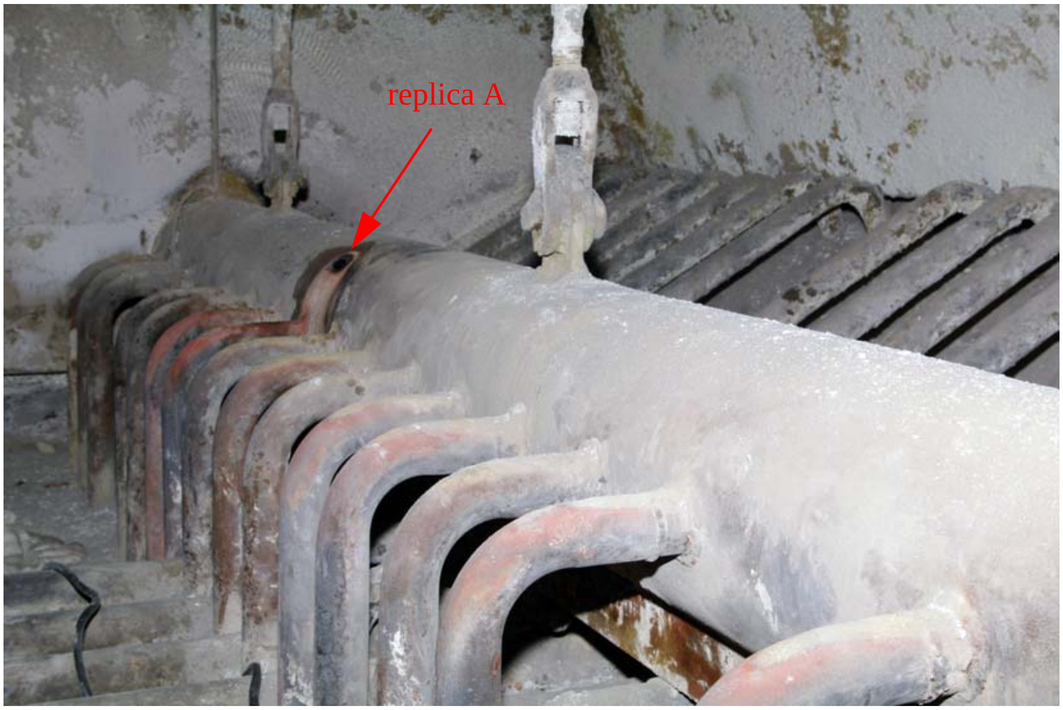

FIGURE 49. Location of replica A.

FIGURE 50. Location of replica B.

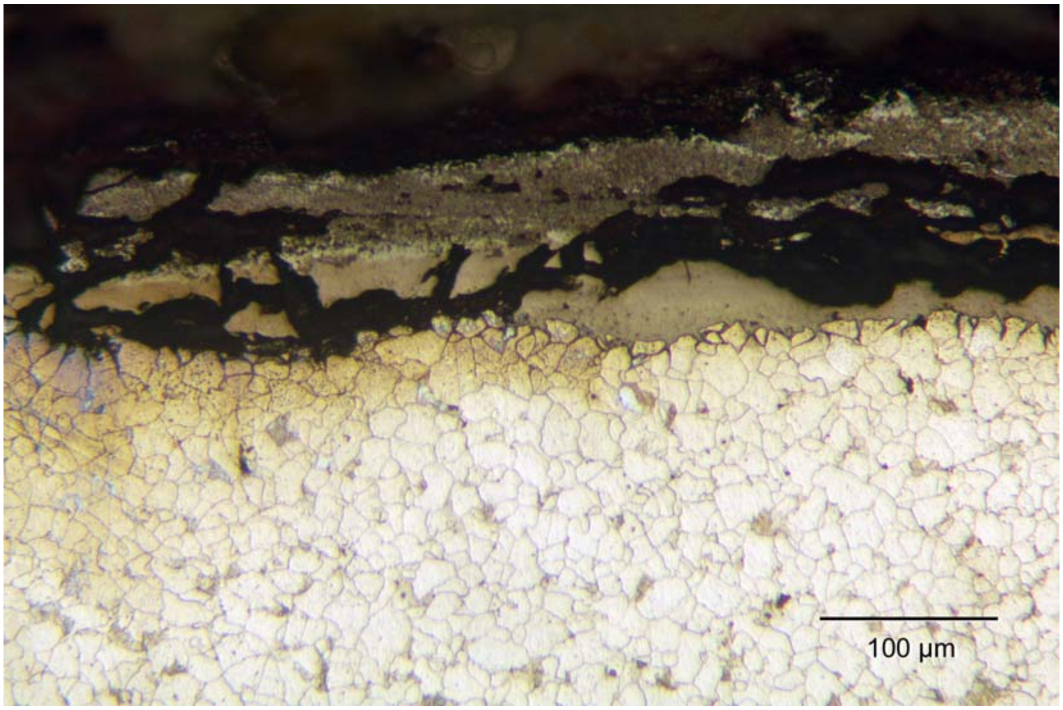

FIGURE 51. Outer microstructure of the superheater tubing removed from inside the furnace. nital etchant

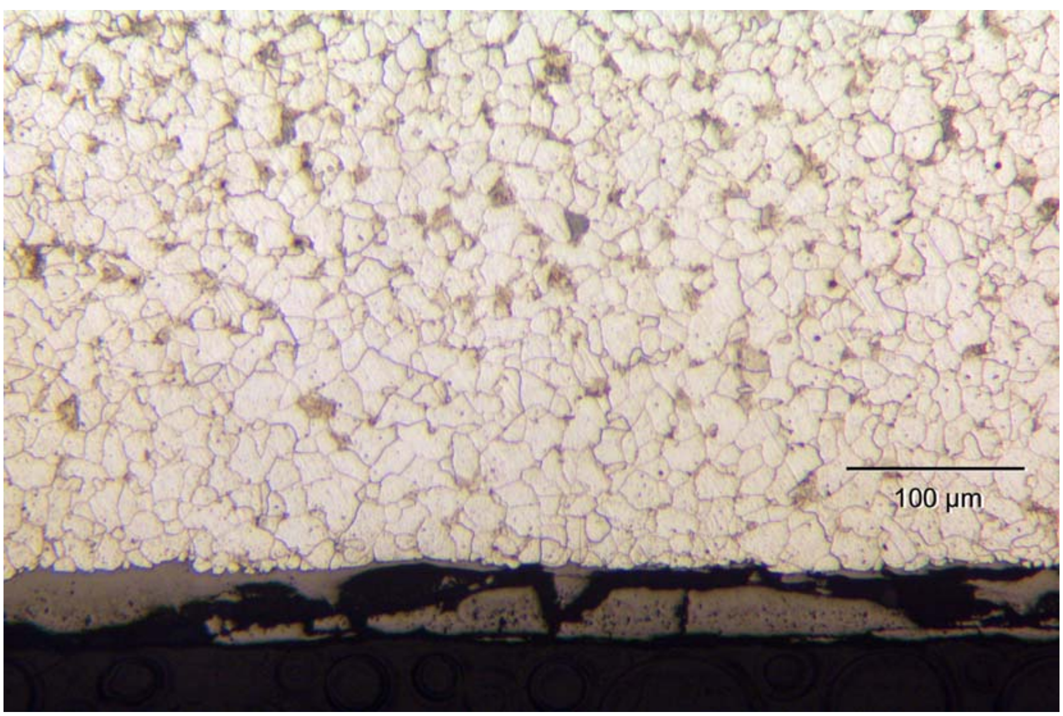

FIGURE 52. Inner microstructure of the superheater tubing removed from inside the furnace. nital etchant

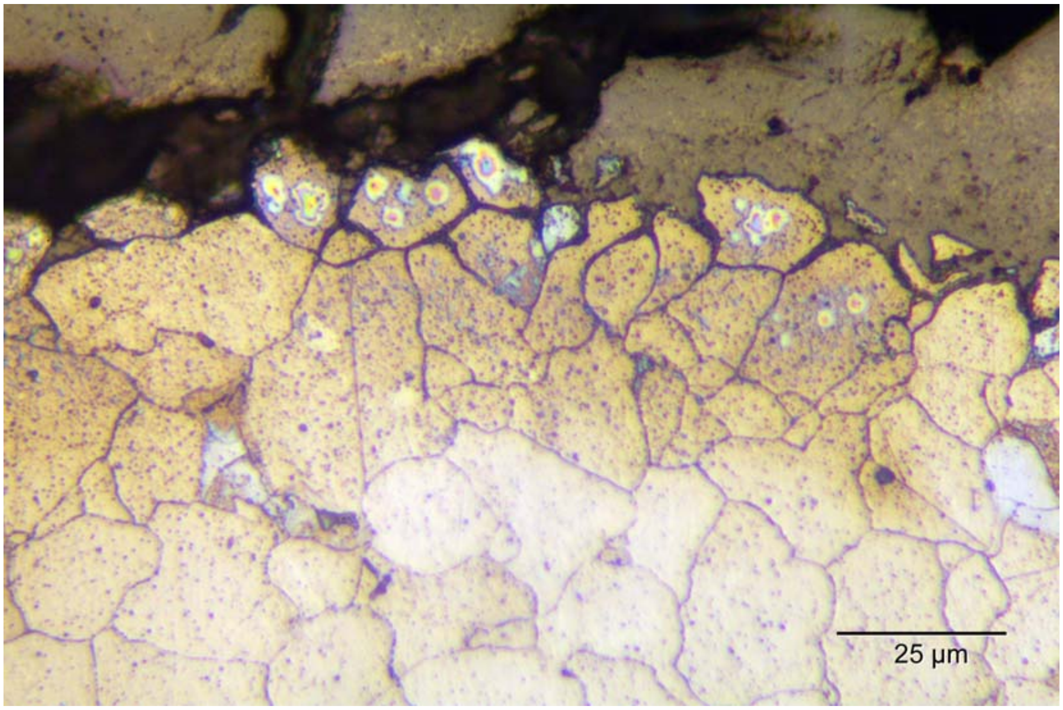

FIGURE 53. Higher magnification micrograph of the outside of the superheater tubing sample from the furnace. nital etchant.

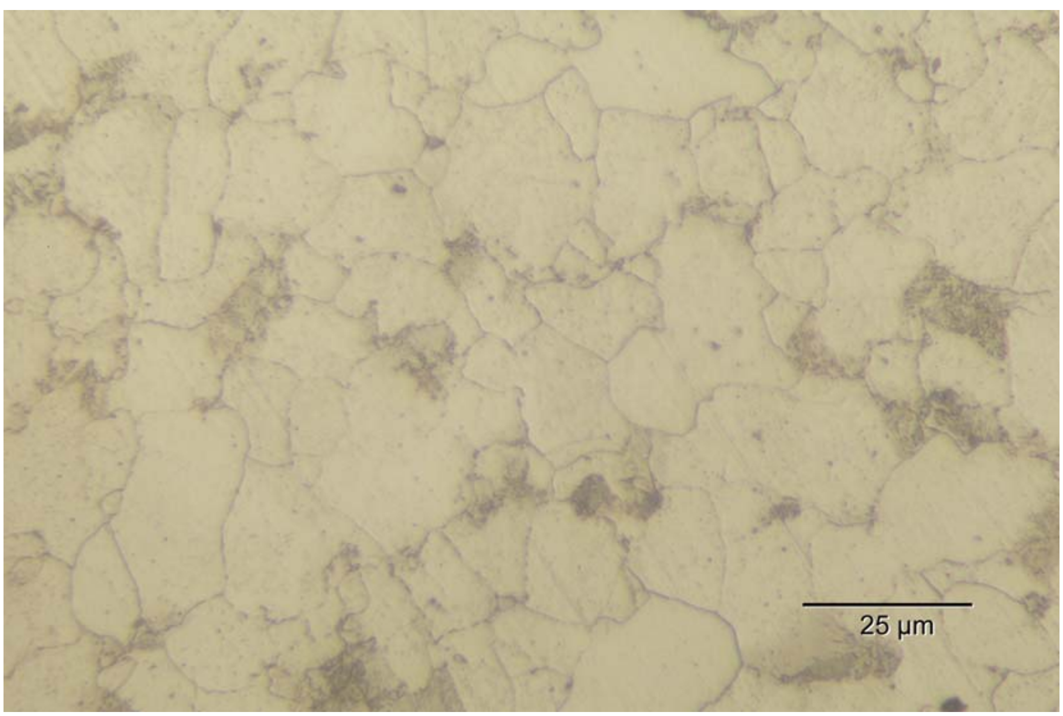

FIGURE 54. Core microstructure of the superheater tubing sample from the furnace. nital etchant

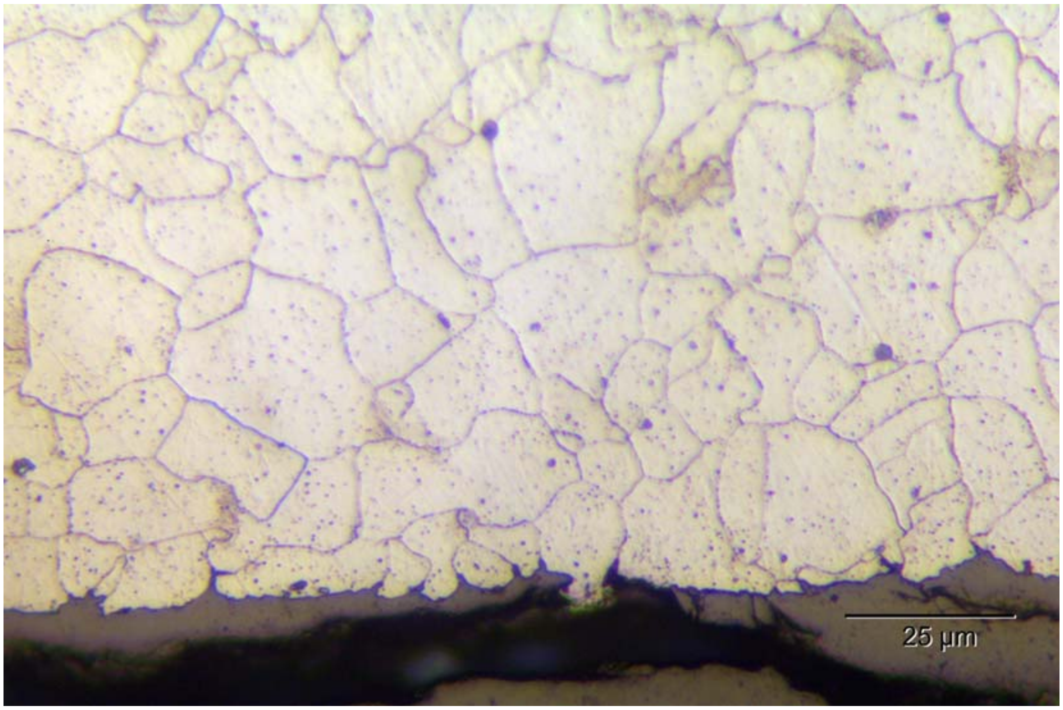

FIGURE 55. Higher magnification view of the inner microstructure for the superheater tube in the furnace. nital etchant

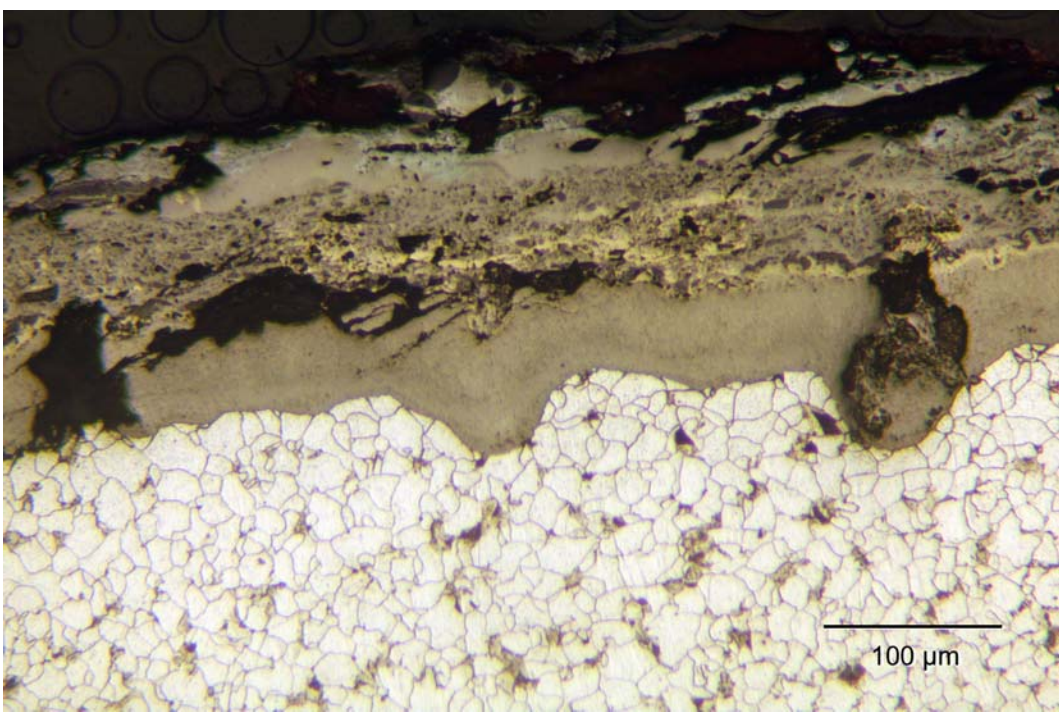

FIGURE 56. Outer microstructure for the superheater tube section removed from the penthouse. nital etchant

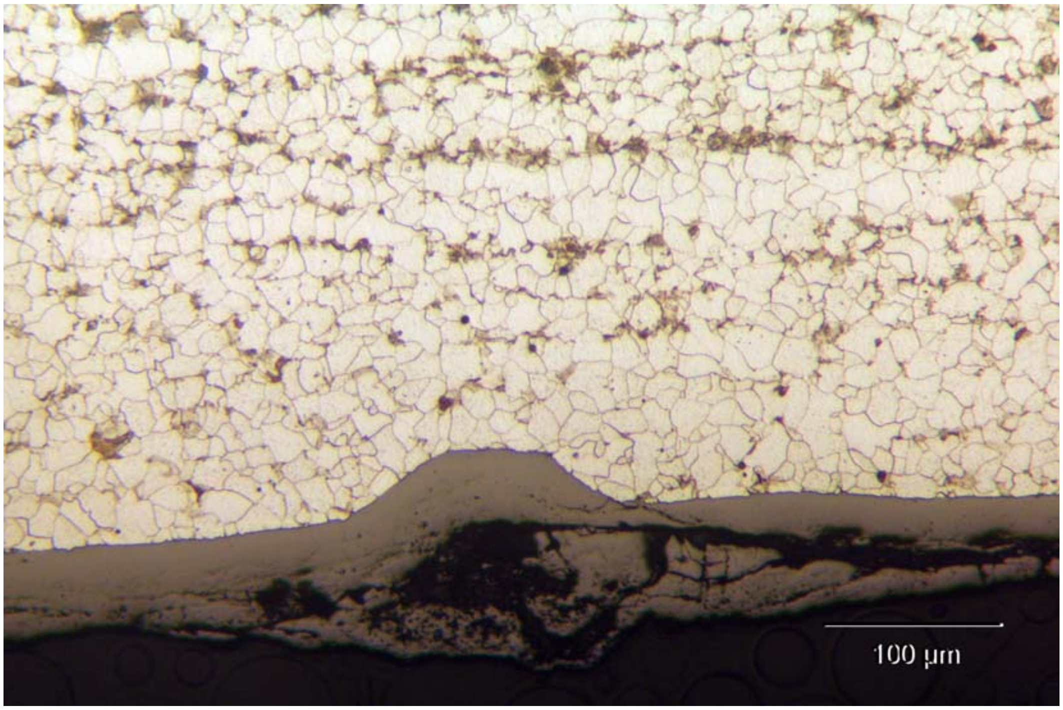

FIGURE 57. Inner microstructure for the penthouse superheater section. nital etchant

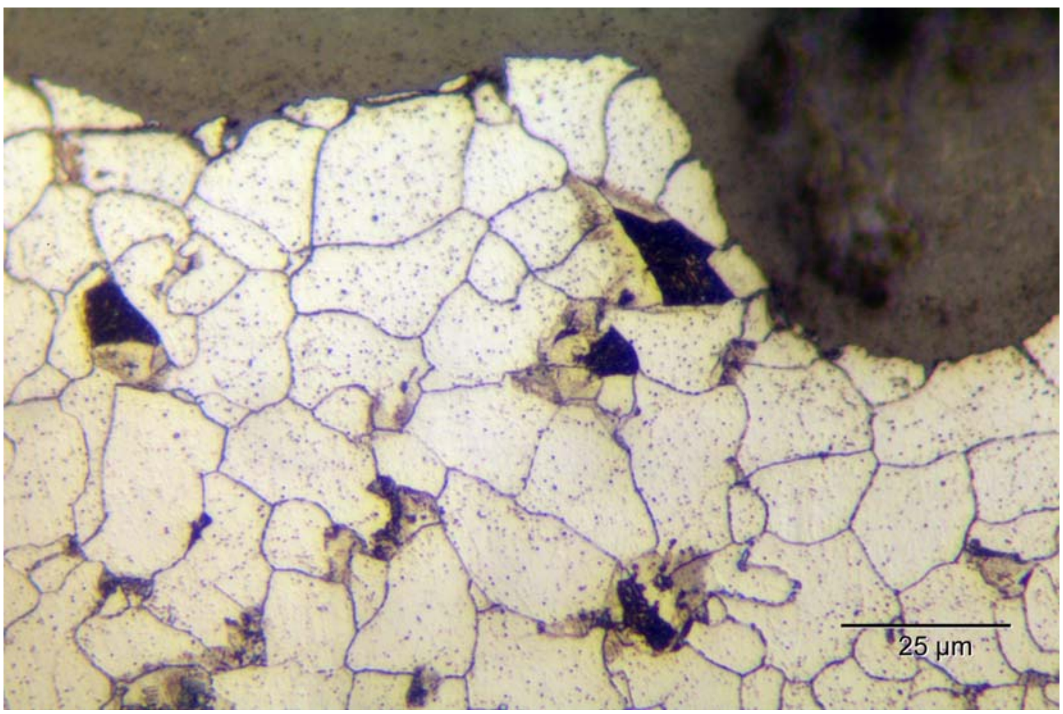

FIGURE 58. Higher magnification view of the outer microstructure for the penthouse superheater tube. nital etchant

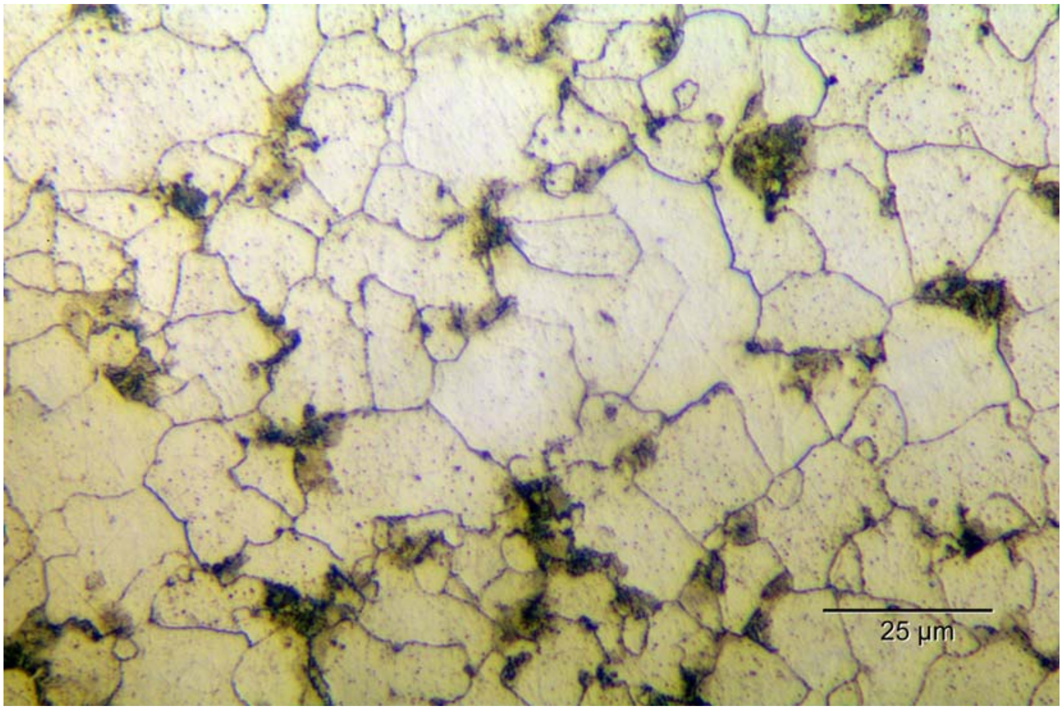

FIGURE 59. Core microstructure for the penthouse superheater tube. nital etchant

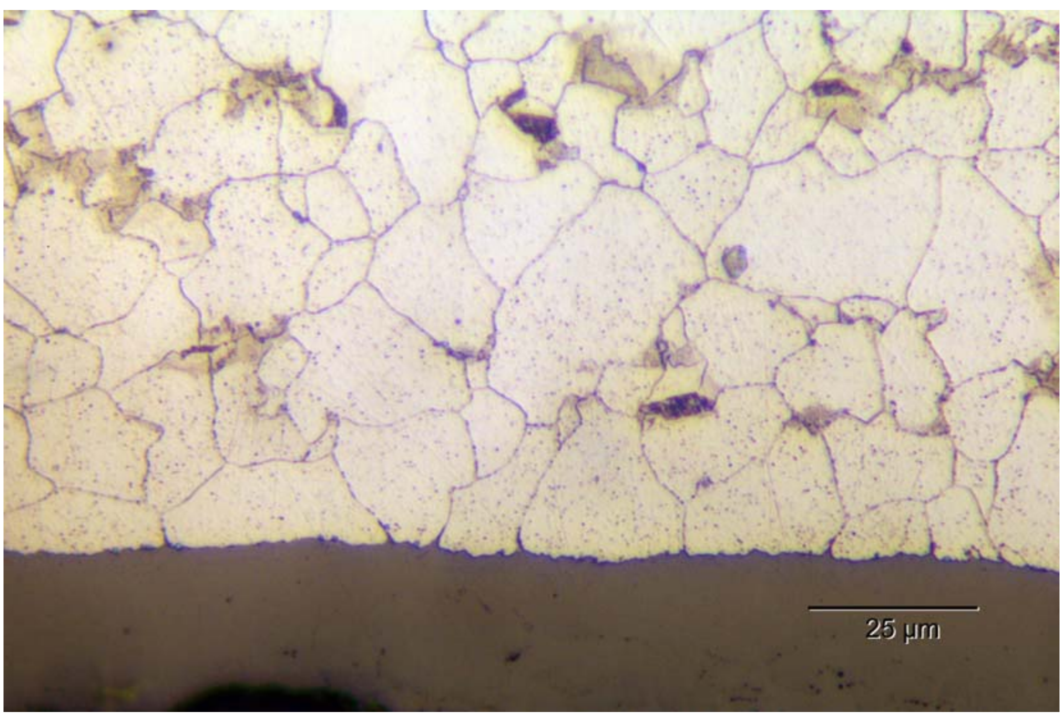

FIGURE 60. Higher magnification inner microstructure for the penthouse superheater tube. nital etchant

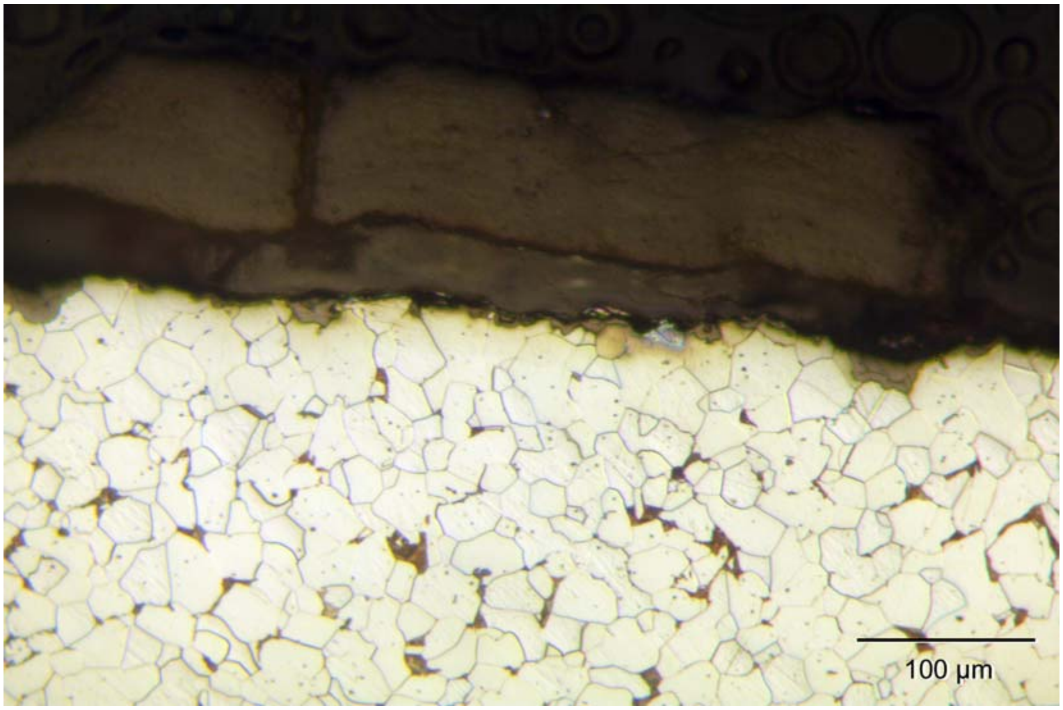

FIGURE 61. Outer microstructure of the generating bank tube removed from the east. nital etchant

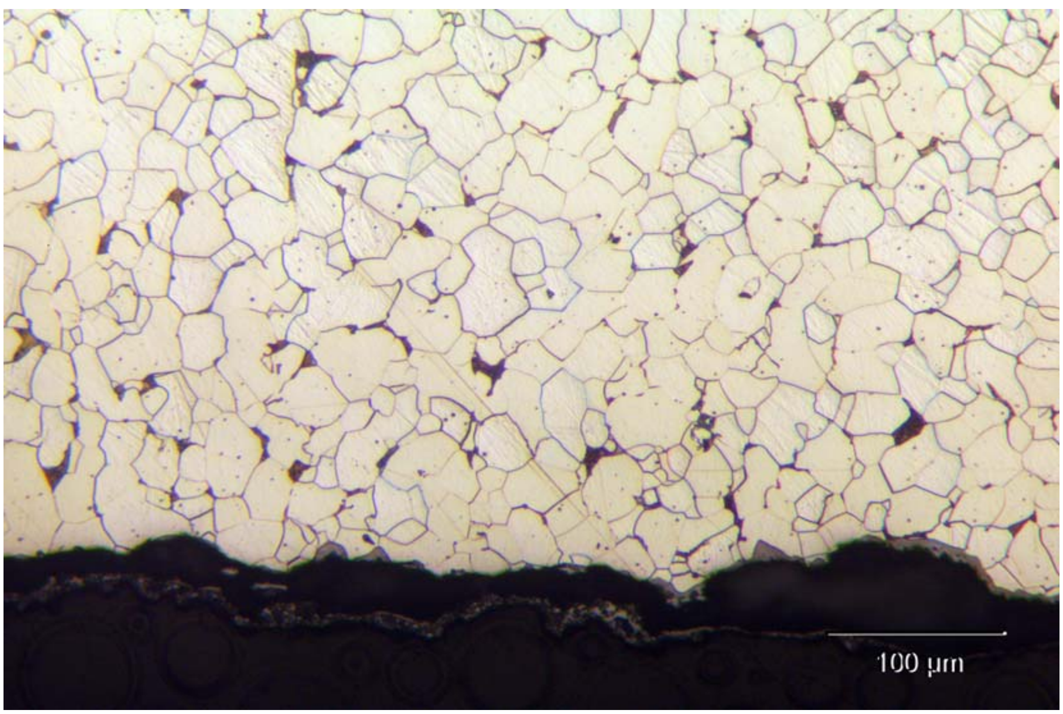

FIGURE 62. Inner microstructure of the generating bank tube removed from the east. nital etchant

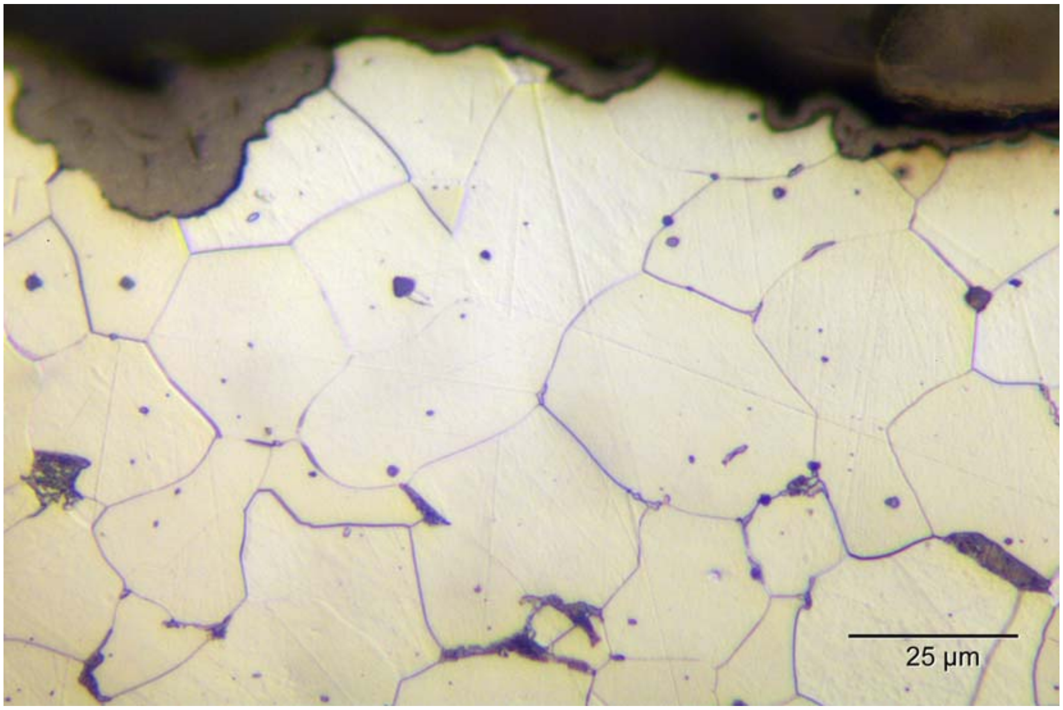

FIGURE 63. Higher magnification view of the outer microstructure of the generating bank tube removed from the east. nital etchant

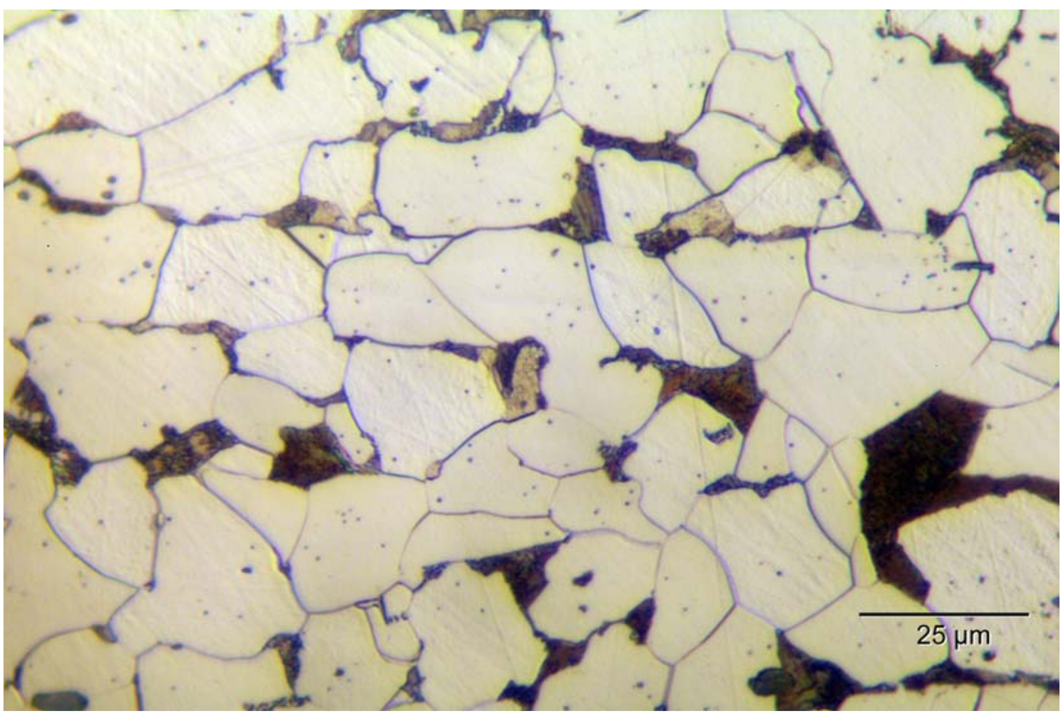

FIGURE 64. Core microstructure of the generating bank tube removed from the east. nital etchant

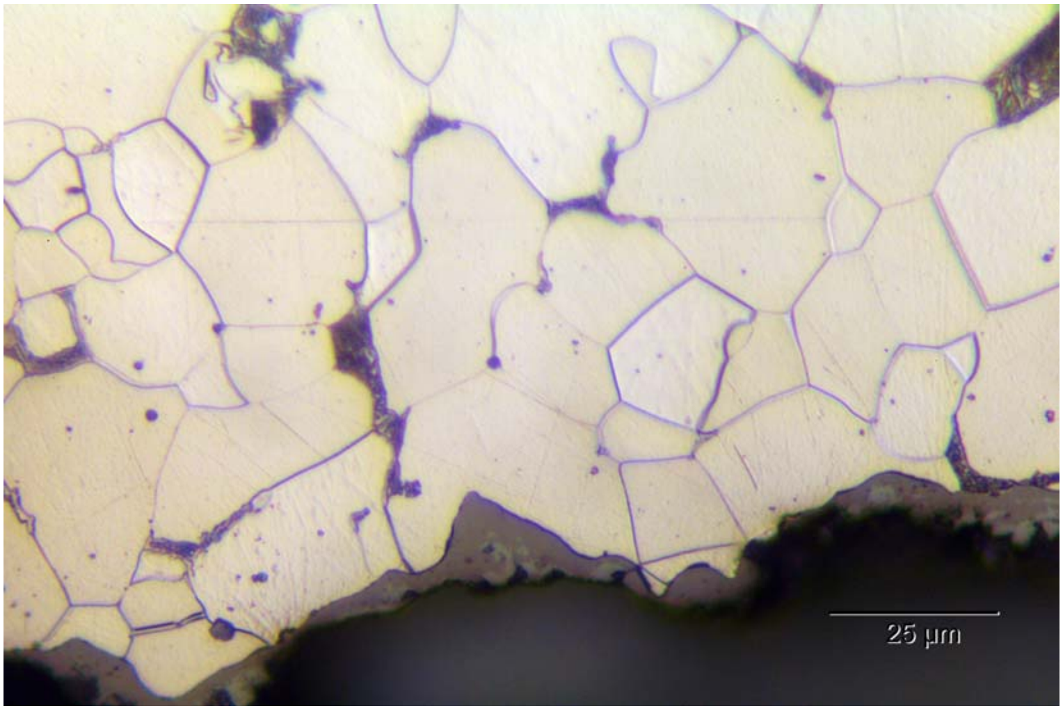

FIGURE 65. Higher magnification view of the inner microstructure of the generating bank tube removed from the east. nital etchant

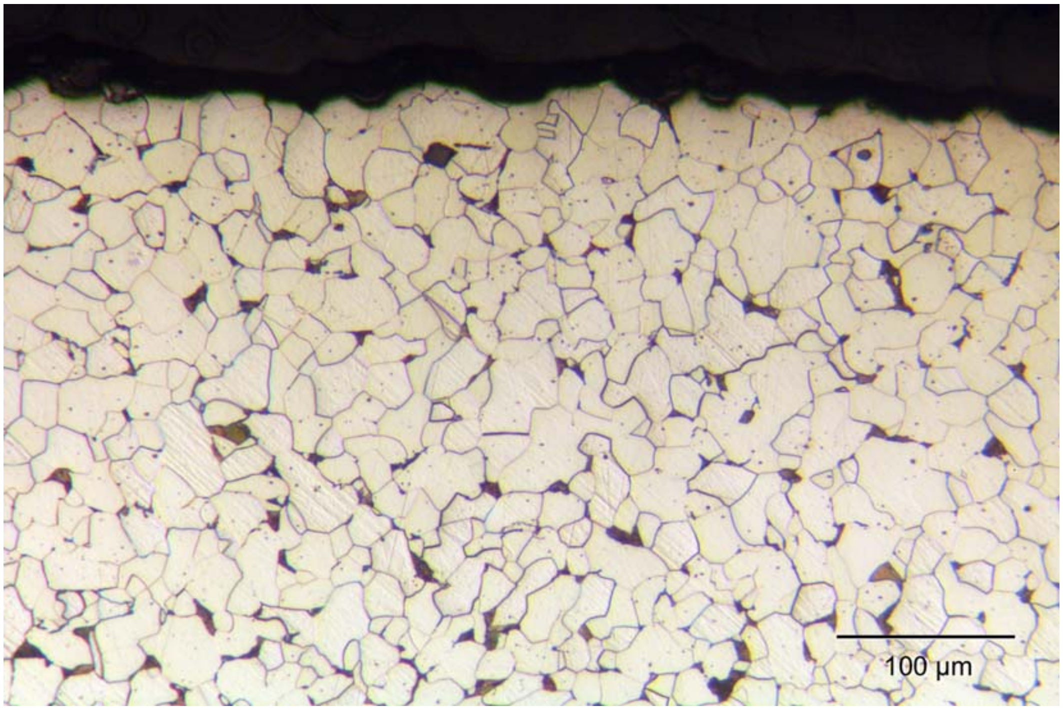

FIGURE 66. Outer microstructure of the generating bank tube removed from the west. nital etchant

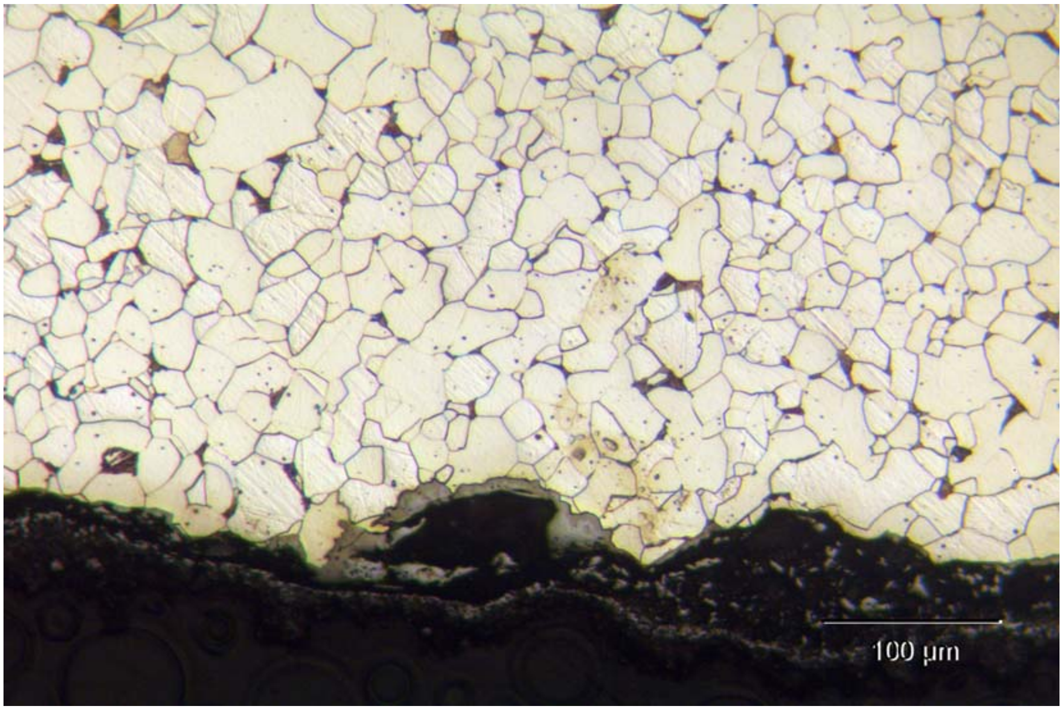

FIGURE 67. Inner microstructure of the generating bank tube removed from the west. nital etchant

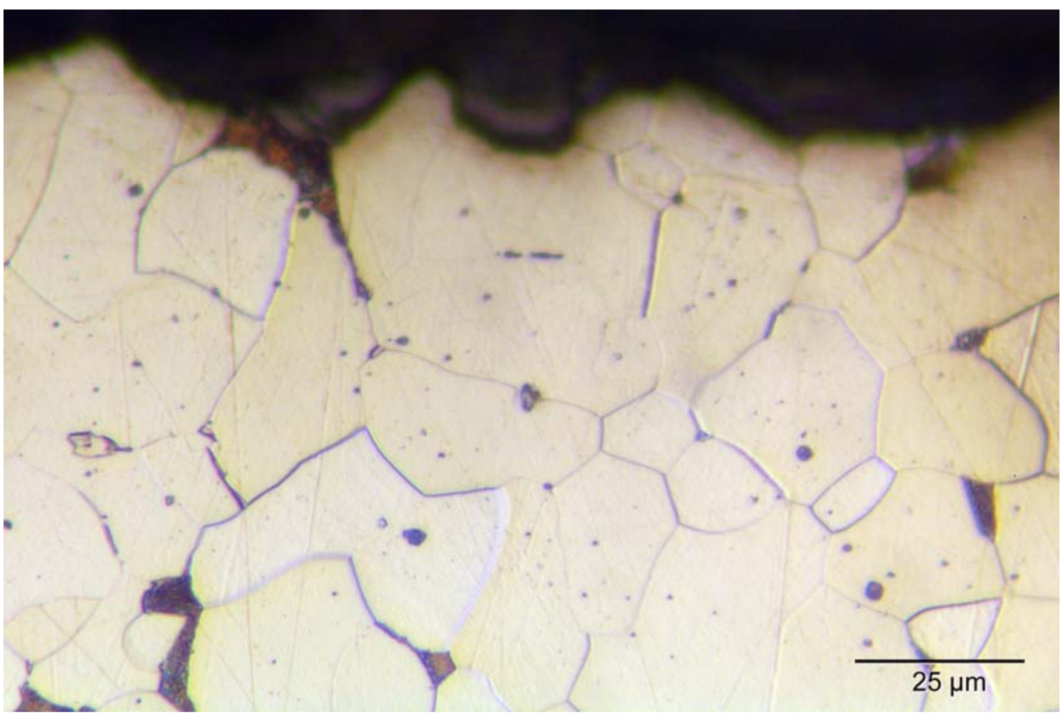

FIGURE 68. Higher magnification view of the outer microstructure of the generating bank tube removed from the west. nital etchant

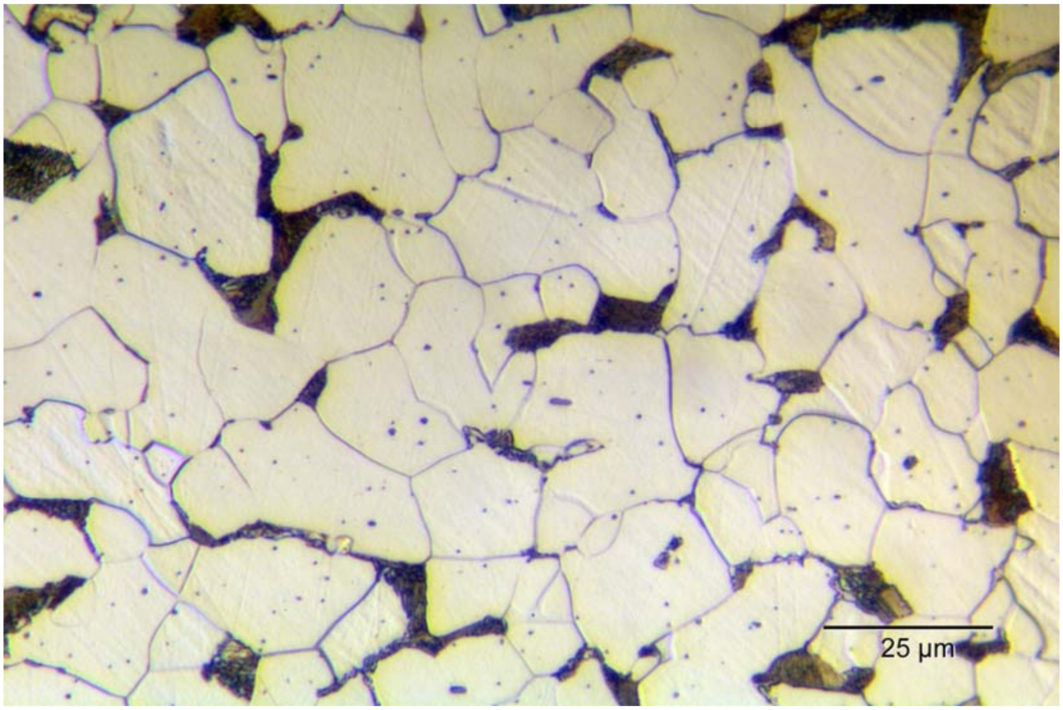

FIGURE 69. Core microstructure of the generating bank tube removed from the west. nital etchant

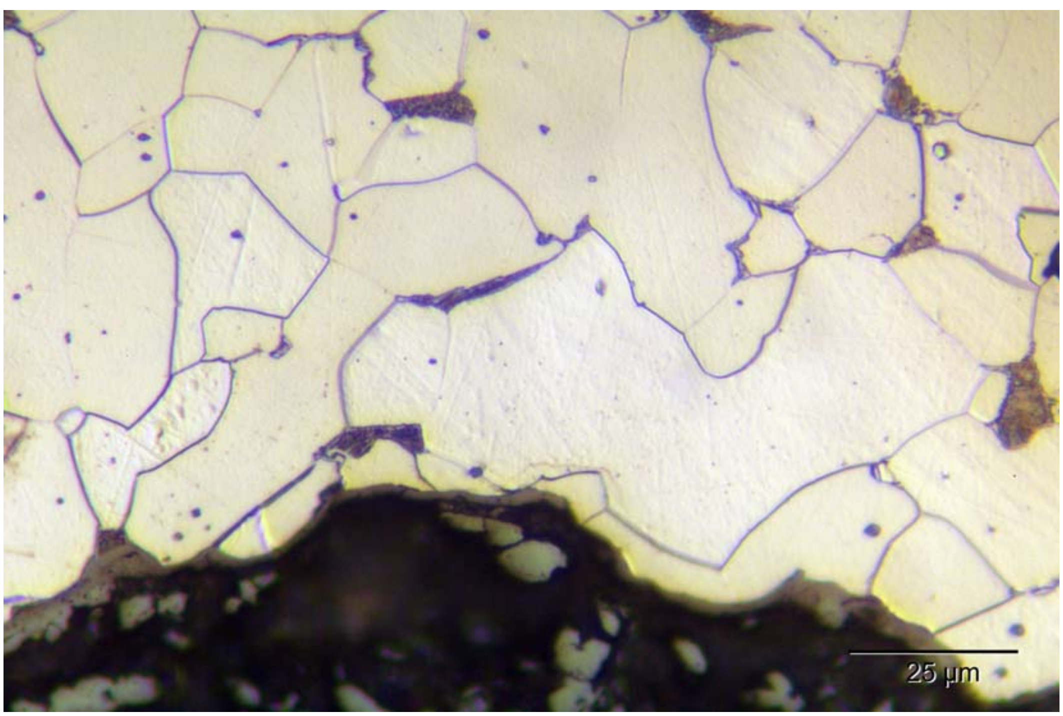

FIGURE 70. Higher magnification view of the inner microstructure of the generating bank tube removed from the west. nital etchant

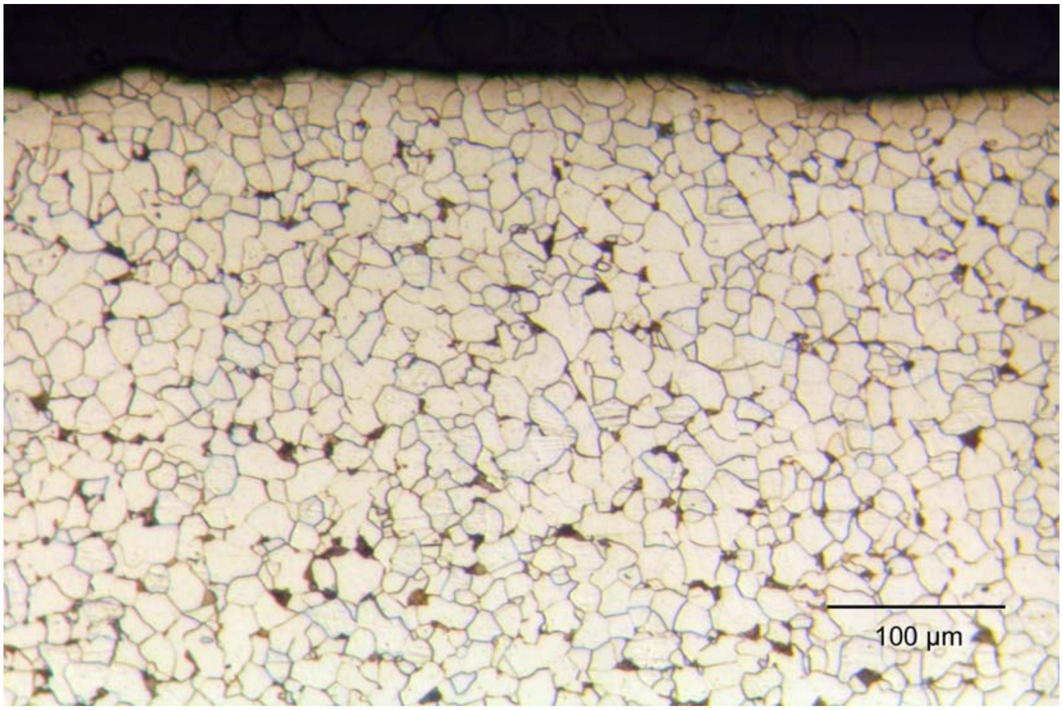

FIGURE 71. Outer microstructure for the economizer tube. nital etchant

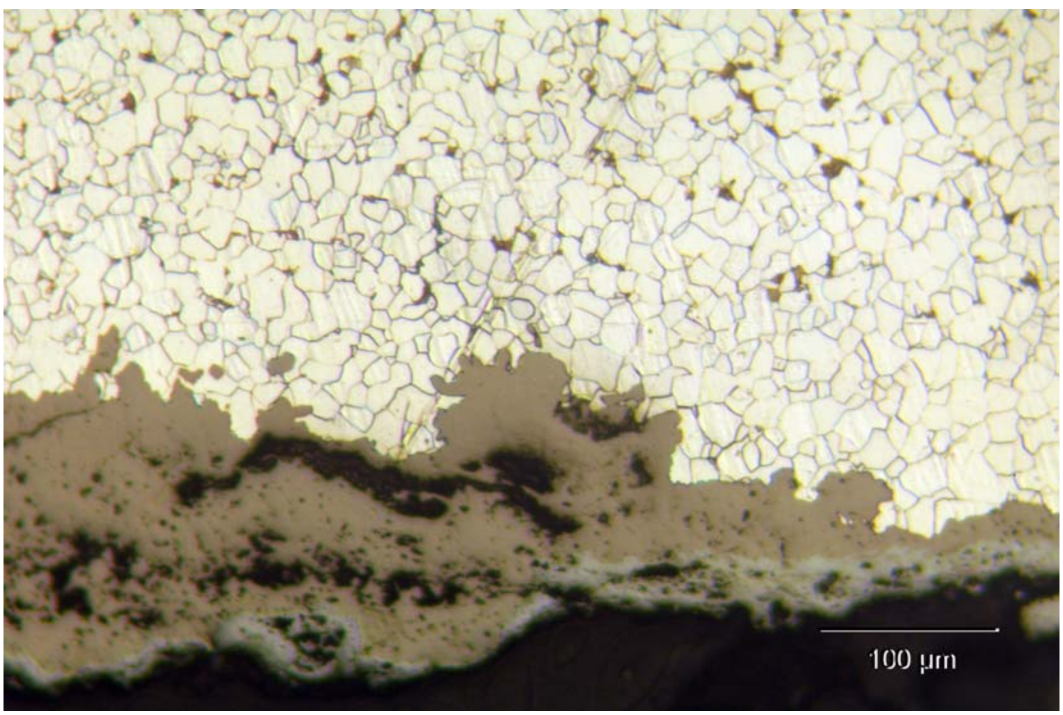

FIGURE 72. Inner microstructure for the economizer tube. nital etchant

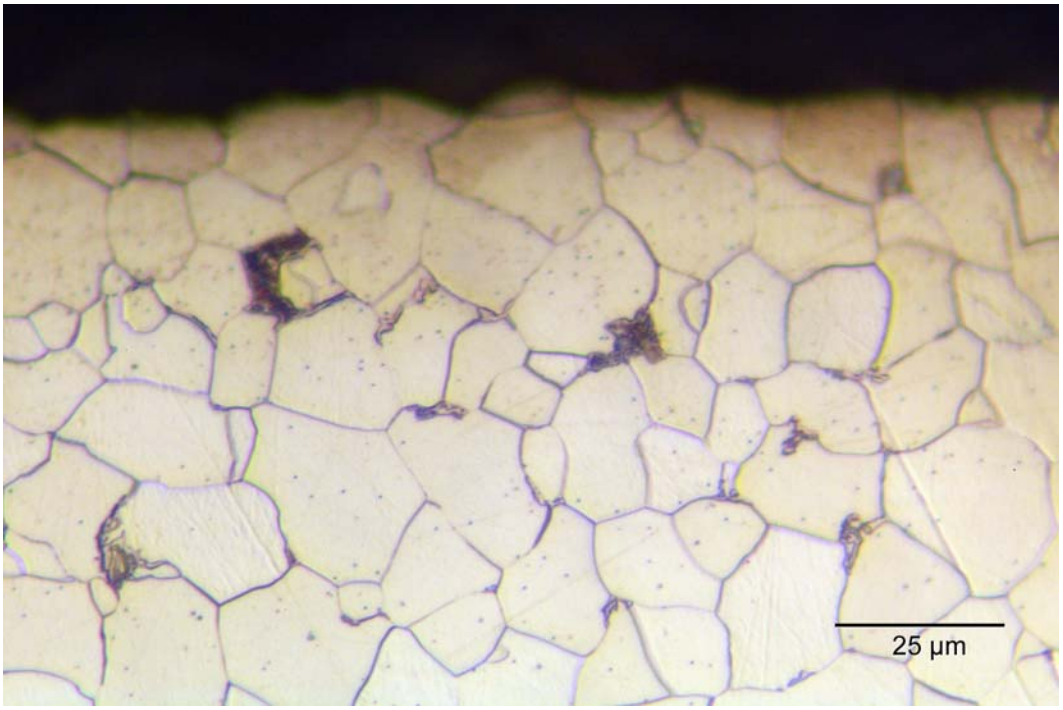

FIGURE 73. Higher magnification view of the outer microstructure for the economizer tube. nital etchant

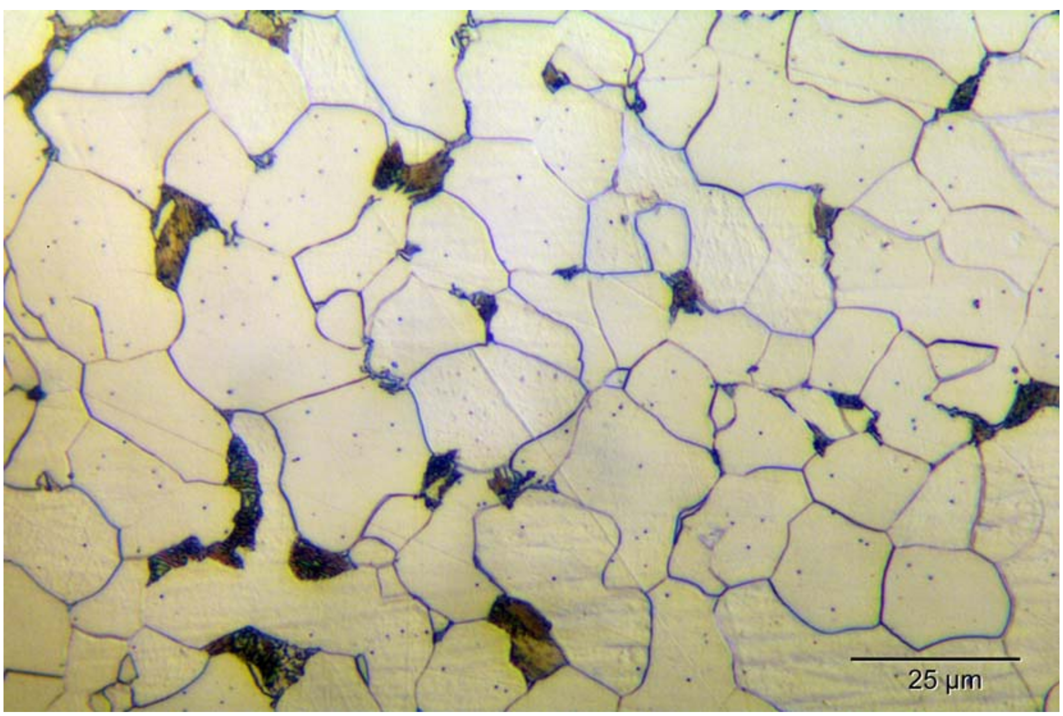

FIGURE 74. Core microstructure for the economizer tube. nital etchant

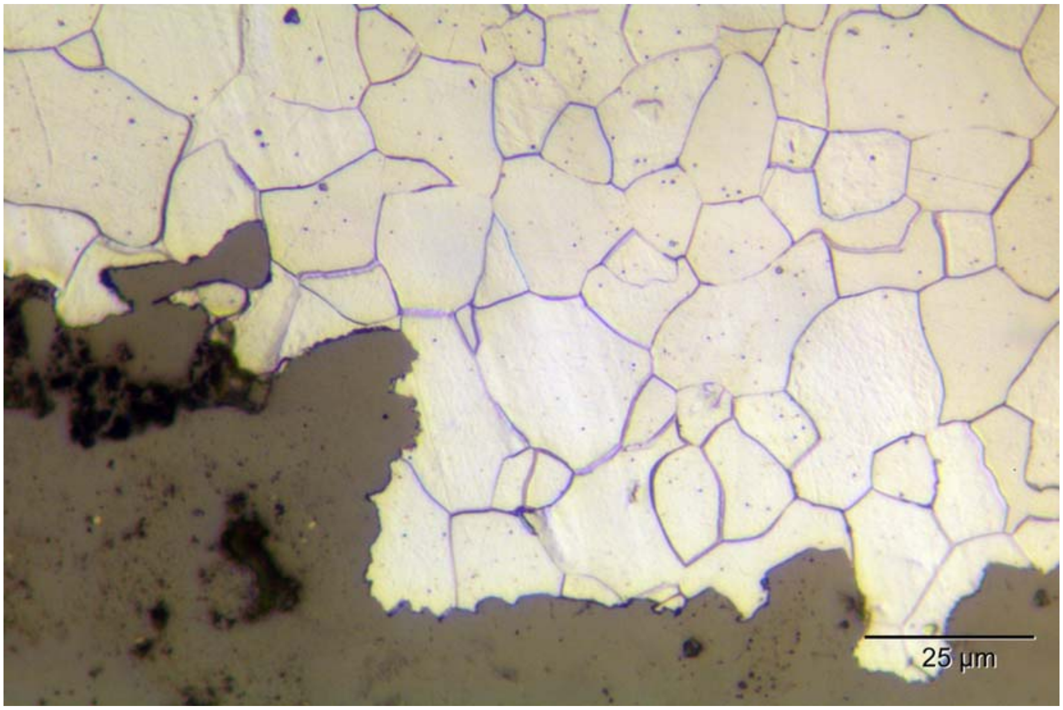

FIGURE 75. Higher magnification view of the inner microstructure for the economizer tube. nital etchant

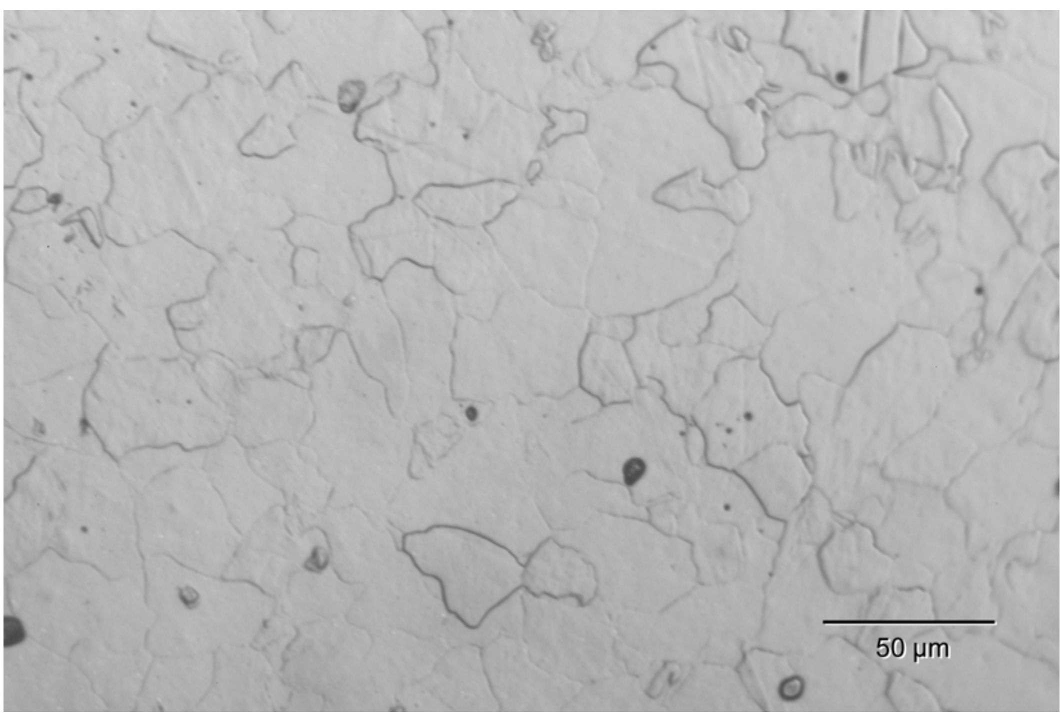

FIGURE 76. Replicate microstructure from location A on the superheater outlet header.

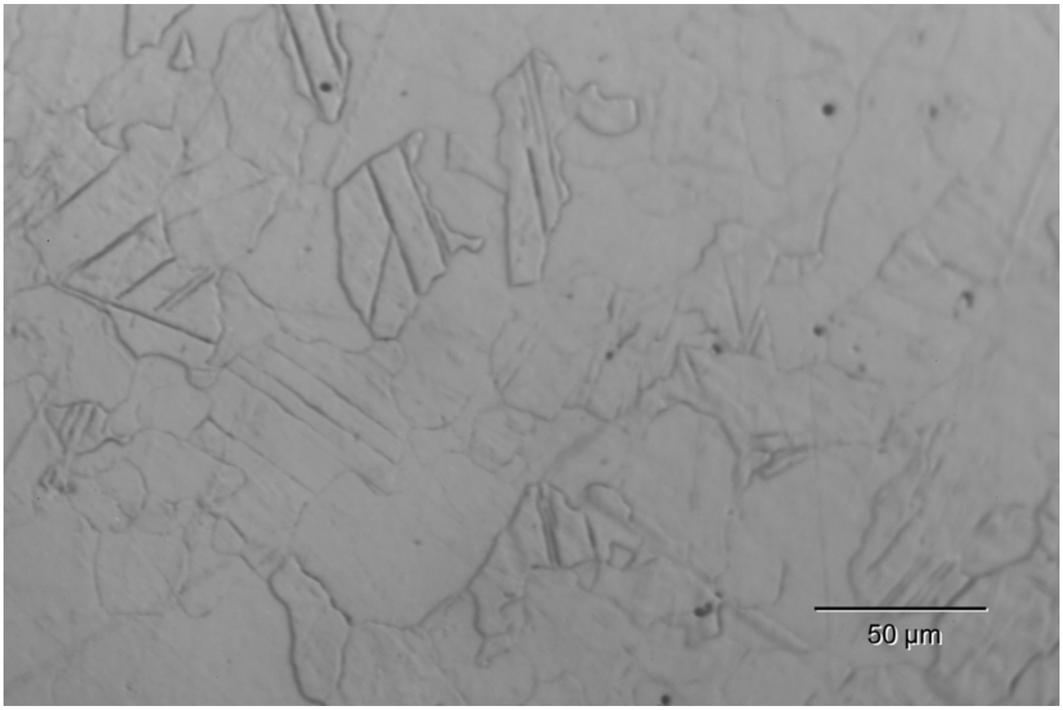

FIGURE 77. Replicate microstructure from location B on the superheater outlet header.

Conclusions

Based on the above evaluation, the following conditions were noted:

- The boiler appears to have been maintained properly over its operational history.
- The outside of the boiler in good condition.
- The grate has suffered wear hindering proper air flow, this is a normal routine maintenance item.
- The water wall tubing has thinned to some degree at the higher elevations within the boiler, though probably still able to perform reasonably.
- The rear wall and the superheater pendants have significant amounts of slag buildup greatly decreasing heat transfer and hence efficiency.
- The superheater pendants examined do not show any signs of creep damage or detectable thinning,
- The generating bank also has significant build-up and several tubes have failed requiring plugs in the headers, both conditions greatly affect efficiency.
- The generating bank tubes show evidence of significant thinning based on the limited ultrasonic thickness survey (most of the tubes are not accessible to conventional UT measurements).[1]
- The economizer has significant debris present and the lower bends have thinned excessively.
- The metallurgical condition of the tubing is normal for the materials specified.
- The drums and headers are in good condition and assuming continued operation within design limits should provide service for many years to come (i.e., 15 to 20 years)

The main concern noted during the evaluation relates to the excessive amounts of slag buildup in the superheats, the generating bank, and the economizer. It is likely the soot blower configuration is inadequate and as such is not properly removing the fines allowing for the formation of slag and/or related debris.

With the exception of the generating bank and economizer tube wastage, the boiler is in good condition without any evidence of metallurgical degradation, such as creep or significant corrosion, in the areas examined.

Due to the lack of historical data on tube and other component thicknesses it is not feasible to perform remaining life calculations with any real meaning based on depletion. Original wall thickness along with changes in thickness over time are required. Wall loss, whether internal or external, may vary considerably through time due to changing operating conditions and hence it is best to have several thickness measurements taken during a boiler's lifetime. It is of limited value to use original manufacturing specifications as most components under consideration are supplied thicker than specified, but it can be used as a very general check on wall loss. Based on the visual and ultrasonic thickness measurements; the tubing, headers, and drums inspected do not appear to have suffered any significant reduction in thickness with the exception of the generating bank and economizer tubing noted above. If the original specified thicknesses are assumed, the headers and drums, and the tubing in many locations have not lost measurable thickness and as such should provide continued service for many years if properly maintained and operated. This conclusion is

1. Other methods such as remote field eddy current (RFEC), as performed by Coastal, and ultrasonic IRIS (internal rotating inspection system) can be used to inspect tubing of this type. Both methods have significant strengths and weaknesses and in each case are highly dependent on technician interpretation and experience. Our experience, which includes performing eddy current testing as an ASNT Level III, suggests that the data generated from either type of testing can miss significant defects that are present, particularly in the bend areas of tubing, when isolated corrosion exists, or when external tube supports are present. The Coastal report did not detect significant thinning in tubes adjacent to those that had failed previously and were subsequently plugged. Our limited UT survey suggests that several tubes in these areas have thinned considerably. It is possible that the thinning occurred subsequent to their testing, but not likely. Further information regarding the limitations and applicability of various test methods can be supplied upon request.

consistent with Coastal's report that calculated greater than 10 years remaining life for the drums and headers. ASME Code calculations can be provided on request, but considering significant wall loss has not occurred in the drums or headers, these calculations were not performed.

The generating banks tube do evidence significant thinning, so the following calculation is provided for guidance in estimating the minimum allowable wall thickness, t. The conservative approach is to use the design pressure, P, of 750 psi and assume a metal temperature not to exceed 700ºF which results in an allowable stress, S, of 12,400 psi.[1] Using these values and a tube diameter of 2.5 inches EQ 1 can be solved to find the minimum wall thickness allowed.[2]

$$t = \frac{PD}{2S + P} + 0.005D = \frac{750(2.5)}{2(12400) + 750} + 0.005(2.5) = 0.0859 \text{ in} \qquad \text{(EQ 1)}$$

The ultrasonic thickness measurements found several tubes having wall thicknesses below this amount with 0.081 inches as the thinnest recorded. Another approach that is more reflective of actual operating conditions is provided below. This method establishes the minimum wall thickness based on the inner radius, R_I, as the tube diameter decreases when outside damage is experienced and the inner radius stays constant. Additionally, the actual operating pressure, which lower than the design value, is used.

$$t = \frac{PR_I}{S - \frac{P}{2}} = \frac{625\left(\frac{2.5}{2} - 0.120\right)}{12400 - \frac{625}{2}} = 0.0584 \text{ in} \qquad \text{(EQ 2)}$$

Typically, this approach still allows continued operation without failure as there is a safety factor included in the allowable stress value used. Assuming operation below creep inducing temperatures, a general rule of thumb allows for wastage of the tube wall to 40% of the original for safe operation.[3]

Obviously, generating bank tubes have failed in the past and more failures are likely to occur. Localized damage not detectable by the methods used to this point may exist. Root cause failure analysis of tube failures as they occur can provide helpful information regarding the mechanisms involved and aid in the selection of methods to locate other suspect tubing.

The economizer has experienced tube wastage, the extent is somewhat unknown due to the caps that have been placed over the tube bends. The thinnest area noted is 0.067 inches which is approximately 45% of the original wall so, areas of concern do exist within the economizer.Similar calculations for the waterwall and superheater tubing were not carried out due to the lack of thinning found in these areas.

In general, it would have been advantageous to have more historical reporting of past thickness data and metallurgical conditions for more of the boiler components. Previous reports did not address the metallurgical condition of the generating bank tubes, the superheater tubes, or the headers. Additionally, past UT thickness data is not available for the upper areas of the waterwalls, generating bank, or superheats. A better assessment of changes through time can be generated when historical comparisons are available. The Hartford report covers some of the metallurgical aspects, but the report is more than 20 years old, and as such, is of limited value. The Coastal report only provides metallurgical information regarding one waterwall tube which is not subject to creep conditions. Remaining life tube assessment requires known data points, whether they be thickness or metallurgical condition, to make reliable predictions.

1. *2007 ASME Boiler & Pressure Vessel Code, Section II, Part D, Materials, 2009 Addenda,* p. 8.
2. *2009 ASME Boiler & Pressure Vessel Code, Section I,* p. 14.
3. French, David N.,1993, *Metallurgical Failures in Fossil Fired Boilers*, John Wiley & Sons, Inc., p 31.

Recommended Major Boiler Repair Plan

We have made several recommendations for long-term repair plans. The repair plans are based on the assumption that the electric plant will operate continuously for the majority of the time during an operating year with the exception of planned and forced outages. If the electric plant is operated for a few load peaks and for compliance tests and annual capacity tests then the plan of "fix what is broken" may be the best economical approach. However, if the plant owner is considering routine continuous operation of the electric plant then the following items should be budgeted in the operating plan:

5 Year recommendations

1. Schedule a Detroit Stoker representative to adjust grate seals and replace worn links. Grate seal work will improve capacity and efficiency, so consider a year one completion cycle. The work would cost approximately $30,000.
2. Replace chill row tubes along both sides of the grate. The boiler has 8 tubes total. The chill tube thicknesses are currently adequate, but are typically high wear items and replacement should be considered within the next two to three years. This would cost approximately $25,000.
3. Consider the addition of steam or sonic soot blowers in the generating bank and economizer. Soot blower additions to the boiler generating bank and economizer will reduce the boiler and economizer outlet temperatures which is a direct efficiency improvement. A rule of thumb is a 40°F boiler exit temperature reduction is a 1% boiler efficiency improvement. While we have not calculated the current performance or the change for the original performance, one to two percent boiler efficiency would not be an unexpected improvement from a normally clean back pass. The efficiency improvement would yield a reasonable pay back. We would consider the soot blower additions a year one or two recommendation. The cost would be estimated as follows:

   3.1. Economizer: add 4 steam rotary electric steam soot blowers at $100,000.

   3.2. Generating Bank: add 4 rotary electric steam soot blower at $135,000
4. Acid cleaning might also be worthy of consideration during the first five years of operation. Based on data from the D.O.E. web site, scale thickness verses efficiency loss varies from 3.9% to 6.2% for 1/16 inch scale thickness. The current scale quality appears to indicate that a removal process of "Acid Cleaning" or online de-scaling process by qualified water chemists could be expected to pay back in a year of regular operation. The cleaning chemicals may be disposed of through the city, but a thorough review with the city water engineer is warranted prior to the cleaning operation. The removal process could be accomplished by an online process or by an acid cleaning contractor. Estimated cost of $50,000 to $100,000.

10 Year recommendations

5. Superheater brackets are recommended to maintain alignment spacing in a uniform manner. Also, modern bracket equipment control expansion direction so all movement is vertical in the pendant superheater elements. When the elements move out of plane, flow restrictions occur. Additionally, slag accumulation increases due to blocking of the normal flow paths. When flow is blocked in one area other areas experience increased velocities and erosion acceleration. Superheater bracket upgrade is recommended after the first 5 years of operation on a continuous basis. The uniform tube spacing will reduce superheater erosion possibilities and facilitate tube cleaning. Installation of cast alloy support devices will cost approximately $50,000 consisting of two rows of support castings.
6. Replace the generating bank tubes. The boiler has generating bank tube failures in the past history. The cause of the failures is outside the scope of this project. Possible causes are fire side erosion from soot blower operation or fly ash erosion. The other possibilities are water side corrosion or fire side corrosion. We expect cold end corrosion in the economizer, but not in the generating bank of the boiler due to operating temperature of the boiler (approximate 680 psig to 700 psig in the steam drum). Removing scale form the generating bank should improve the flue gas distribution and reduce back pass velocities back

to the original design values. The lower velocities can reduce the fly ash erosion if that is the cause of the generating bank tube failures. So if the general operation is improved by soot blower operation the need for generating bank replacement may be reduced or extended. For that reason we suggest the generating bank replacement be planned for between 5 and 10 years for the start of continuous operation. The work can be completed in phases if budgeting concerns prevent complete replacement at one time. It is practicable to complete the re-tube process in 2 phases with the center soot blower lane as the dividing line between phases. Tube plugs are present in approximately 4% of the generating bank tubes (based on a simple count of the plugs noted in the steam drums). The ultrasonic thickness measurements suggest that a much greater number of tubes have thinned significantly. The total cost replacing the entire generating bank is approximately $350,000.

7. The economizer return bends (180º) show measured signs of erosion or metal loss. Economizer corrosion is accelerated by cyclic operation as there is no way to eliminate dew point corrosion when the boilers are removed from operation during periods of no electric demand on the power plant. So continuous operation is expected to extend the life of the economizer to allow continued operation. Economizer erosion can be expected to continue however the damage is typically localized and routine tube shield replacement should reduce erosion caused maintenance to be a routine issue only. Some tube replacement of the economizer should be considered routine maintenance and complete replacement should be part of a ten year plan. The cold end tube rows 12, 13, 14, and 15 can be replaced for $45,000.

Respectfully submitted,

Tim Locke, P.E., President

Scott Kessler, P.E., Ph.D., ASNT Level III

Appendix

UNION IRON WORKS

1 - 3

SUBSIDIARY OF RILEY STOKER CORPORATION
ERIE, PENNA.

FORM P-3 MANUFACTURERS' DATA REPORT FOR WATER-TUBE BOILERS, SUPERHEATERS, WATERWALLS, AND ECONOMIZERS

As Required by the Provisions of the ASME Code Rules — S-90784

1. Manufactured by UNION IRON WORKS, ERIE, PENNSYLVANIA (Name and address of manufacturer)
2. Manufactured for City of Jasper, Jasper, Indiana (Name and address of purchaser)
3. Identification Bent Tube Water Tube (Type of boiler, superheater, waterwall, economizer) Boiler No. 23424 (Mfrs. Serial No.) - - (State and State No.) 4038 (Nat'l. Board No.) Year Built 1967
4. The chemical and physical properties of all parts meet the requirements of material specifications of the ASME BOILER AND PRESSURE VESSEL CODE. The design, construction, and workmanship conform to ASME Rules, Section I (I or IV) Dated 1965

Remarks: Manufacturers' Partial Data Reports properly identified and signed by Commissioned Inspectors have been furnished for the following items of this report: 42" Drum - Struthers Wells Corporation 48-2427-1
54" Drum - Struthers Wells Corporation 48-2427-2
(Name of Part—Item number, manufacturer's name, and identifying stamp)

See Supplement Sheet Attached.

We certify the statement in this data report to be correct.

Date March 29, 19 67 Signed UNION IRON WORKS (Manufacturer) By G. O. Larsen (Representative)

Certificate of Authorization Expires December 31 19 67

CERTIFICATE OF SHOP INSPECTION

BOILER MADE BY UNION IRON WORKS at ERIE, PENNSYLVANIA

I, the undersigned, holding a valid commission issued by the National Board of Boiler and Pressure Vessel Inspectors and/or the State of ______ and employed by Hartford Steam Boiler Inspection & Insurance Co. of HARTFORD, CONN. have inspected parts of this boiler referred to as data items 3,4,5-A,5-B,6-A,6-B,7-A and have examined manufacturer's partial data reports for items 7-B,8-A,8-B,9-A,10,11 and state that, to the best of my knowledge and belief, the manufacturer has constructed this boiler in accordance with the applicable sections of the ASME BOILER AND PRESSURE VESSEL CODE.

By signing this certificate neither the Inspector nor his employer makes any warranty, expressed or implied, concerning the boiler described in this manufacturer's data report. Furthermore, neither the Inspector nor his employer shall be liable in any manner for any personal injury or property damage or a loss of any kind arising from or connected with this inspection.

Date 4/28/1967

La Lork (Inspector) Commissions N.B. 1947 (Nat'l Board or State and No.)

We certify that the field assembly of all parts of this boiler conforms with the requirements of SECTION I of the ASME BOILER AND PRESSURE VESSEL CODE.

Date 9-25, 1967 Signed Riley Stoker Corp (Assembler) By Clyde S. Ouellet (Representative)

Our Certificate of Authorization to use the A-4514 (A) or (S) Symbol expires Dec 31 19 67

CERTIFICATE OF FIELD ASSEMBLY INSPECTION

I, the undersigned, holding a valid commission issued by the National Board of Boiler and Pressure Vessel Inspectors and/or the State of ______ and employed by THE HARTFORD S.B. I. & I Co of HARTFORD CONNECTICUT have compared the statements in this manufacturer's data report with the described boiler and state that the parts referred to as data items 6B, 8B, 9A, 12, not included in the certificate of shop inspection have been inspected by me and that to the best of my knowledge and belief the manufacturer and/or the assembler has constructed and assembled this boiler in accordance with the applicable sections of the ASME BOILER AND PRESSURE VESSEL CODE. The described boiler was inspected and subjected to a hydrostatic test of 1125 psi.

By signing this certificate neither the inspector nor his employer makes any warranty, expressed or implied, concerning the boiler described in this manufacturer's data report. Furthermore, neither the Inspector nor his employer shall be liable in any manner for any personal injury or property damage or a loss of any kind arising from or connected with this inspection.

Date 9-25 19 67

E. J. Stevens Jr. (Inspector) Commissions NB 4773 (Nat'l Board or State and No.)

1961

5(a) DRUMS

No.	Nominal diameter in.	Length Ft. In.	Shell plates Brand	Material Spec. No.	Thickness	Inside radius	Tube sheets Thickness	Inside radius	Tube hole ligament efficiency Longitudinal	Circumferential
1	54	21' - 0"	Firebox	SA-212-B	3-1/4"	27	3-1/4"	27	40.5	29.1
2	42	22' - 11"	Firebox	SA-212-B	2-1/2"	21	2-1/2"	21	42.1	30.5
3										
4										

No.	Longitudinal joints No. & type *	Efficiency	Circum. joints No. & type	Efficiency	Heads Brand	Material spec. no.	Thickness		Type**	Radius of dish	Manholes No.	Size	Hydrostatic test, lb.
1	2 2	100	3 2	100	Firebox	SA-212-B	2-1/4"	2-1/4"	3	–	2	12 x 16	–
2	2 2	100	3 2	100	Firebox	SA-212-B	1-3/4"	1-3/4"	3	–	2	12 x 16	–
3													
4													

* Indicate if 1. Seamless; 2. Fusion welded; 3. Forged welded; 4. Riveted. ** Indicate if 1. Flat; 2. Dished; 3. Ellipsoidal, 4. Hemispherical.

5(b) BOILER TUBES

Diameter	Thickness	Material specification no.
2-1/2"	.120	SA-178-A

5(c) HEADERS NO. ____________________
(Box or sinuous; Mat. spec. no.; Thickness)

HEADS OR ENDS ____________________ HYDRO. TEST-LB. ________
(Shape; Mat. spec. no.; Thickness)

5(d) STAYBOLTS ____________________
(Mat. spec. no.; Diameter; Size telltale; Net area)

PITCH __________ NET AREA __________ MAX. S.W.P. __________
(Supported by one bolt)

5(e) MUD DRUM ____________________ HEADS OR ENDS ____________________ HYDRO. TEST-LB. ________
(For sect. header boilers. State size; Shape; Mat. spec. no.; Thickness) (Shape; Mat. spec. no.; Thickness)

6(a) WATERWALL HEADERS / 6(b) WATERWALL TUBES

No.	Size and shape	Material spec. no.	Thickness	Heads or Ends Shape	Thickness	Material spec. no.	Hydro. test, lb.	Diameter	Thickness	Material spec. no.
3	10"x 20'2"	SA-106-B	1"	Flat	1-3/8"	SA-212-B	–	3	.135	SA-178-A
2	10"x 17'0"	SA-106-B	1"	Flat	1-3/8"	SA-212-B	–	4	.150	SA-178-A
1	10"x 19'0"	SA-106-B	1"	Flat	1-3/8"	SA-212-B	–	6	Sch. 40	SA-106-B

7(a) ECONOMIZER HEADERS / 7(b) ECONOMIZER TUBES

2	8" x 5'2"	SA-106-B	3/4"	Flat	1-3/8"	SA-212-B	–	2	.150	SA-178-A

8(a) SUPERHEATER HEADERS / 8(b) SUPERHEATER TUBES

1	10" x 20'0"	SA-106-B	1"	Flat	2"	SA-212-B	–	2	.150	SA-210-C
1	10" x 19'3"	SA-106-B	1"	Flat	2"	SA-212-B	–	2	.148	SA-213-T12
1	10" x 22'6"	SA-335-P11	Sch. 100	Flat	1-5/8"	SA-204-B	–			

9(a) OTHER PARTS (1) (2) (3) / 9(b) TUBES FOR OTHER PARTS

1										
2	No Connection to Item #10									
3										

Economizer Openings: 2 - 1-1/2" Nozzles, 7 - 3/4" to $1\frac{1}{4}$" Couplings
1 - 2", 4 - $1\frac{1}{2}$", 8 - 1" Nozzles

10 OPENINGS (1) Steam 11 - 3/4" to 1-1/4" Couplings (2) Safety valve 2 - 2", 1 - $1\frac{1}{2}$" Nozzles
(No., size, and type of nozzles or outlets) (No., size, and type of nozzles or outlets)

(3) Blow-off 1 - 1" Nozzle, 8 - $1\frac{1}{2}$", 2 - 1" Couplings (4) Feed 1 - 4", 1 - $1\frac{1}{2}$" Nozzles
(No., size, and type of nozzles or outlets) (No., size, type, and location of connections)

11

		Maximum Allowable Working Pressure	Code Par. and/or Formula on which AWP is Based	Shop hydro. test	Heating surface
a	Boiler	750	PG-29	–	12,288
b	Waterwall	750	PG-31	–	1,965
c	Economizer	820	PG-31	1230	5,180
d	Superheater	750 @ 825F	PG-42	–	3,925
e	Other parts				

Heating surface to be stamped on drum heads.

This heating surface not to be used for determining minimum safety valve capacity

12 Field hydro. test
1125

SUPPLEMENT, BOILER NATIONAL BOARD NO. 4038

2-3

UNION IRON WORKS

Subsidiary OF RILEY STOKER CORPORATION
ERIE, PENNA.

FORM P-4 MANUFACTURERS' PARTIAL DATA REPORT

As Required by the Provisions of the ASME Code Rules

S-90784

1. (a) Manufactured by UNION IRON WORKS, ERIE, PENNSYLVANIA
(Name and address of manufacturer of part)

(b) Manufactured for CITY OF JASPER, JASPER, INDIANA
(Name and address of manufacturer of boiler or vessel)

2. Identification – Manufacturer's Serial No. of ~~PART~~ Boiler 23424

(a) Constructed According to Blueprint No. ______ B.P. Prepared by ______

(b) Description of Part Inspected ______

3. If welded, what paragraphs of the Code (Part PW) have been complied with? ______

(Continued from P-3 Data)

4. Remarks: There are 8 - 6", 6 - 4", 148 - 3" and 252 - 2½" Stubs, 1 - 10" x 6" Reducer, 1 - 1½" Blow-off Pipe Extension, 5 - 4" Pipe Closures in Drums and Headers Prepared for Field Welding. Each Sidewall Supply Tube has two Shop Welds. Each Bridgewall Supply and Frontwall Tube has two Joints Prepared for Field Welding. Desuperheater, consisting of 10" x 20' long Pipe, is welded between two Stages of Superheater and has 1 - 1" and 1 - 4" Openings.

We certify the statements in this manufacturer's partial data report to be correct and that all details of material, construction, and workmanship of this boiler part conform to the ASME Boiler and Pressure Vessel Code.

Date March 29, 19 67 Signed UNION IRON WORKS (Manufacturer) By J. O. Larsen (Representative)

Certificate of Authorization Expires December 31 19 67

CERTIFICATE OF SHOP INSPECTION

I, the undersigned, holding a valid commission issued by the National Board of Boiler and Pressure Vessel Inspectors and/or the State of ______ and employed by Hartford Steam Boiler Inspection & Insurance Co. of HARTFORD, CONN. have inspected the part of a boiler described in this manufacturer's partial data report on ______ 19___, and state that to the best of my knowledge and belief, the manufacturer has constructed this part in accordance with the applicable sections of the ASME BOILER AND PRESSURE VESSEL CODE.

By signing this certificate, neither the Inspector nor his employer makes any warranty, expressed or implied, concerning the part described in this manufacturer's partial data report. Furthermore, neither the Inspector nor his employer shall be liable in any manner for any personal injury or property damage or a loss of any kind arising from or connected with this inspection.

Date 4/20/ 19 67

[illegible] Inspector Commissions N.B. #1947 Nat'l Board or State and No.

1966

FORM P-4 MANUFACTURERS' PARTIAL DATA REPORT 3·3

As Required by the Provisions of the ASME Code Rules

1. (a) Manufa Struthers Wells Corporation, Titusville, Pennsylvania
(Name and address of Manufacturer of part)

(b) Manufactured for Union Iron Works, Erie, Pa.
(Name and address of Manufacturer of boiler or vessel)

2. Identification – Manufacturer's Serial No. of Part 48-2427-1 for 42" Drum
48-2427-2 for 54" Drum

(a) Constructed According to Blueprint No. 41-1780 & 41-1781 B. P. Prepared by Struthers Wells Corp.

(b) Description of Part Inspected (1) Drum 42" I.D. x 21'-3" Lg. Between Head Seams.
(1) Drum 54" I.D. x 20'-0" Lg. Between Head Seams.

3. If welded, what paragraphs of the Code (Pars. P-69 to P-77 inclusive) have been complied with? Sect. I, Par. PQ-1 thru PW-53

4. Remarks: All material furnished by Union Iron Works, Erie, Pa.
Drums fabricated by welding of long't, & girth seams.
Long't. & girth seams are 100% X-rayed, with seams ground flush. Heat treating and hydro. testing to be done by others.

We certify the statements in this manufacturer's partial data report to be correct and that all details of material, construction, and workmanship of this boiler part conform to the ASME Boiler and Pressure Vessel Code.

Date Sept. 27, 19 66 Signed Struthers Wells Corp. (Manufacturer) By J. A. Hine (Representative)

Certificate of Authorization Expires Dec. 31, 19 67

CERTIFICATE OF SHOP INSPECTION

I, the undersigned, holding a valid commission issued by the National Board of Boiler and Pressure Vessel Inspectors and/or the State ______

and employed by Hartford Stm. Blr. Insp. & Ins. Co. Hartford, Conn

have inspected the part of a boiler described in this manufacturer's partial data report on ______ 19 ___, and state that to the best of my knowledge and belief, the manufacturer has constructed this part in accordance with the applicable sections of the ASME BOILER AND PRESSURE VESSEL CODE.

By signing this certificate, neither the Inspector nor his employer makes any warranty, expressed or implied, concerning the part described in this manufacturer's partial data report. Furthermore, neither the Inspector nor his employer shall be liable in any manner for any personal injury or property damage or a loss of any kind arising from or connected with this inspection.

Date NOV 18 1966 19

Harry Burke (Inspector) Commissions N. B. # 3760 (Nat'l Board or State and No.)

Form P-4 (back)

5(a) Drums

No.	Nominal diameter, in.	Length Ft In.	Shell plates Brand	Material spec. no.	Thickness	Inside radius	Tube sheets Thickness	Inside radius	Tube hole ligament efficiency Longitudinal	Circumferential
1	42"	21'-3"	F.B.S.	SA-212-B	2-1/2"	21"	2-1/2"	21"		
2	54"	20'-0"	F.B.S.	SA-212-B	3-1/4"	27"	3-1/4"	27"		
3										
4										
5										

No.	Longitudinal joints No. & type *	Efficiency	Circum. joints No. & type	Efficiency	Heads Brand	Material spec. no.	Thickness		Type**	Radius of dish	Manholes No. Size	Hydrostatic test, lb
1	2-2	100%	3-2	100%	F.B.S.	SA-212-B	1-3/4"	1-3/4"	3			
2	2-2	100%	3-2	100%	F.B.S.	SA-212-B	2-1/4"	2-1/4"	3			
3												
4												
5												

*Indicate if (1) Seamless; (2) Fusion welded; (3) Forge welded; (4) Riveted. **Indicate if (1) Flat; (2) Dished; (3) Ellipsoidal; (4) Hemispherical.

5(b) Boiler Tubes

Diameter	Thickness	Material specification no.

5(c) Headers No. ____ (Box or sinuous; Mat. spec. no.; Thickness)

Heads or Ends ____ (Shape; Mat. spec. no.; Thickness) Hydro. Test, Lb. ____

5(d) Staybolts ____ (Mat. spec. no.; Diameter; Size telltale; Net area)

Pitch ____ Net Area ____ (Supported by one bolt) Max. S.W.P. ____

5(e) Mud Drum ____ (For sect. header boilers. State Size; Shape; Mat. spec. no.; Thickness) Heads or Ends ____ (Shape; Mat. spec. no.; Thickness) Hydro. Test, Lb. ____

6(a) Waterwall Headers / 6(b) Waterwall Tubes

No.	Size and shape	Material spec. no.	Thickness	Heads or Ends Shape	Thickness	Material spec. no.	Hydro. test, lb	Diameter	Thickness	Material spec. no.

7(a) Economizer Headers / 7(b) Economizer Tubes

8(a) Superheater Headers / 8(b) Superheater Tubes

9(a) Other Parts (1) ____ (2) ____ (3) ____ 9(b) Tubes for Other Parts

1										
2										
3										

10 Openings (1) Steam ____ (No., size, and type of nozzles or outlets) (2) Safety Valve ____ (No., size, and type of nozzles or outlets)

(3) Blowoff ____ (No. size, and type of nozzles or outlets) (4) Feed ____ (No., size, type, and location of connections)

11	Bursting pressure weakest part	Maximum S.W.P.	Factor of safety	Shop hydro. test	Heating surface
a Boiler					
b Waterwall					
c Economizer					
d Superheater					
e Other parts					

Heating surface to be stamped on drum heads.

This heating surface not to be used for determining minimum safety valve capacity.

12 Field hydro. test

Appendix B
Data from Bingham McHale

JASPER MUNICIPAL ELECTRIC PLANT AND RENEWABLE ENERGY PROJECT DEVELOPMENT

Prepared for:

THE CITY OF JASPER UTILITY SERVICES BOARD

Prepared by:

BINGHAM McHALE LLP

January 2010

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report is intended to support the Jasper Utility Service Board (Board) in their decision regarding the future of the Jasper Municipal Electric Plant (JMEP or facility), located in the City of Jasper (City). Black & Veatch (B&V) has completed a report regarding the facility's physical condition and market value on an "as-is" basis, and on the basis of life extension improvements. Bingham McHale in this report (Bingham Report) addresses current U.S. energy policies, carbon regulation, renewable energy incentives, renewable energy markets, project development and project finance.

Current U.S. energy policies are intended to support a transformative initiative to reduce reliance on fossil fuels; increase the use of renewable fuels; create a new manufacturing base and jobs in the energy sector; reduce reliance on foreign oil, and, improve national security. These policies include the adoption of renewable portfolio standards (RPS) requiring electric utilities to provide a percentage of their electricity from sources of renewable energy. Thirty states have already adopted RPSs and a federal RPS is currently under consideration by Congress. Renewable energy credits (RECs) are being established to monetize the value of the environmental attributes of facilities capable of producing energy from renewable fuels. Regional tracking systems have been established to facilitate trading and development of REC markets. The intention of these policies is to incentivize the development of energy production facilities capable of firing renewable fuels. [1]

Federal tax incentives have been enacted to encourage the private capital markets to invest in renewable energy projects. These tax incentives include the production tax credit which provides a credit against tax liabilities based upon energy production; the investment tax credit which is based upon the amount of the investment; Treasury grants in lieu of these credits; and, accelerated depreciation. In addition there is direct funding available for renewable energy projects through grants and guaranteed loans, as well as low cost public financing. All of these financial incentives have been greatly expanded under the American Recovery and Reinvestment Act of 2009. [2]

Cap-and-trade is an approach to mitigating greenhouse gas (GHG) emissions and currently is the subject of considerable debate in Congress. Cap-and-trade has been used to regulate the emissions of sulfur dioxide and NOx under the U.S. Environmental Production Agency's (EPA) Acid Rain Program. The program has been highly successful in reducing the levels of these pollutants. The U.S. House of Representatives recently passed the American Clean Energy and Securities Act of 2009, H.R. 2454, 11th Cong. (2009) which includes a cap-and-trade program for GHG emissions. Companion legislation is pending in the Senate, the American Clean Energy Leadership Act, S. 1462, 11th Cong. (2002), which does not include a cap-and-trade program.[3] Considerable debate over the issue is anticipated to continue.

Meanwhile the U.S. Supreme Court recently held that the EPA has the authority to regulate GHG emissions. The agency already has issued proposed rules requiring permits for

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[1] *See* Section II, III and IV.
[2] *See* Section V.
[3] *See* Section VI.

sources of these emissions. The EPA, in absence of Congressional action, is likely to expand regulation of carbon emissions resulting in significant increases in the cost of energy from fossil fuels.[4]

The Energy Information Agency (EIA) released its Annual Energy Outlook 2010 (AE02010) on December 14, 2009, which addresses trends and issues impacting the U.S. energy markets. Electric consumption is forecasted to increase at a rate of 1% from 2008 to 2035. The fossil fuel share of energy consumption is projected to fall from 84% of total U.S. energy demand in 2008 to 78% in 2035. Investments in fewer coal fire plants is anticipated, however, coal will remain a dominant energy source due to the continued reliance on existing coal fired plants, development of clean coal technologies and carbon capture and sequestration, and the need to meet rising base load demands.[5]

Natural gas is expected to play a much greater role in the generation of electricity. This is due to lower GHG emissions and the fact that gas fired plants are much cheaper to build than either coal or nuclear facilities. The concern with greater reliance on natural gas as a fuel for the production of electricity is the historically volatile nature of natural gas prices, which can significantly impact the cost of electricity.[6]

Generation of electricity from renewable fuels is anticipated to increase significantly due to these major policy initiatives. The AEO 2010 projects the share of electric generation from renewable fuels will grow from 9% in 2008 to 17% in 2035. The AEO 2010 reference case assumes no changes in law and that all sunset provisions in existing law will expire as planned. This is not likely to occur. The EPA will be releasing their analysis of other scenarios based upon different assumptions in the near future.[7]

All of these policies, regulations and financial incentives are intended to increase the development of renewable energy facilities, including projects like JMEP. Economics will play a major factor in the decision by the Board. Unfortunately, there is much uncertainty regarding future markets for renewable energy. At this point, it is not known the extent to which current energy policies will continue. Other uncertainties include: future demand for electricity; price volatility in the electric markets; cost of construction of new energy production facilities; development of new power production technologies; and GHG emission regulation. All of these uncertainties make the Board's decision a difficult one.

B&V's report concludes that upgrading the JMEP to co-fire biomass fuels may provide an attractive opportunity. The Bingham Report finds that energy policies, carbon regulation and transitioning energy markets appear to provide favorable prospects for renewable energy facilities. Current uncertainties, however, pose risks with investments in these types of renewable energy facilities.

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[4] *See* Section VI.
[5] *See* Section VII.
[6] *See* Section VII.
[7] *See* Section VII.

I.
INTRODUCTION

The purpose of this report (Bingham Report) is to provide the Jasper Electric Utilities Board (Board) with an additional factual basis for its decision regarding future investment in the Jasper Municipal Electric Plant (JMEP or facility), located in the City of Jasper (City). The Board's decision will be driven by economics, including, the amount of capital investment necessary to upgrade and make the facility capable of firing renewable fuels; operating expenses; future revenue streams from the sale of electricity; value of Renewable Energy Credits (RECs); and, other factors, such as jobs, electric reliability and reduction in greenhouse gas (GHG) emissions. The value of the future income stream from electric sales (commodity) may be enhanced by the facility's ability to fire renewable fuels, including wood wastes, turkey and poultry litter, corn stoves and other agricultural by-products. There also may be added value created by the RECs which are intended to reflect the facility's use of renewable fuels (environmental attributes).

While precise market prices for renewable energy are not available at this time due to many uncertainties, this report will address current and anticipated energy policies, carbon regulation, electric markets, project financing and public-private partnerships. The report is divided into ten sections:

- Introduction
- U.S. Energy Policies
- Renewable Portfolio Standards
- Renewable Energy Credits
- Financial Incentives
- Cap-and-Trade
- Renewable Energy Market
- Project Financing
- Public-Private Partnership
- JMEP Decision

The Bingham Report will supplement the "Plant Condition Assessment Study" prepared by Black & Veach (B&V Report), and provide the Board with a broader factual context within which to make future decisions regarding the Facility.

II.
U.S. ENERGY POLICIES

Current U.S. energy policy is designed to reduce the consumption of electricity; reduce GHG emissions and other pollution from the generation of electricity; lessen the reliance on fossil fuels and increase the use of renewable fuels; reduce the reliance on foreign sources of energy; create new jobs within the energy sector; and, improve national security. While these policy initiatives began as early as the 1970s following the energy crisis of the Carter years, current efforts to transition from fossil fuels to domestic renewable fuels and alternative energy began in earnest in 2005.

The Energy Policy Act of 2005 (EPA)

The Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005) (hereinafter referred to as EPA) was signed into law on August 8, 2005 by President Bush. The EPA is intended to address the increasingly difficult issues relating to the nation's consumption of energy and the nature of our energy supplies. The Act's major provisions include:

- Tax breaks for energy conservation improvements
- Subsidies for renewable and alternative sources of energy
- Loan guarantees for innovative technologies
- Support for clean coal initiatives
- Support for advanced nuclear reactor designs
- Increases in the amount of bio-fuels to be mixed with gasoline
- Federal reliability standards for the nation's electric transmission grid
- Reports by the U.S. Department of Energy (DOE) regarding natural energy resources and demand-side management[8]

While the Act was hailed as a major energy policy initiative, there have been considerable issues with funding and timely implementation.

The Energy Independence and Security Act of 2007 (EISA)

The Energy Independence and Security Act of 2007, Pub. L. No. 110-140, 121 Stat. 1667 (2007) (hereinafter referred to as EISA), was signed into law on December 19, 2007. The EISA is an omnibus energy policy law intended to increase energy efficiency and the availability of renewable energy. Key provisions include corporate average fuel economy standards for fleets of cars and light trucks by model year 2020; expanded requirements for renewable fuel standards applicable to blended gasoline; and, appliance and lighting efficiency standards. Two controversial provisions were not included in the enacted law, which related to renewable energy portfolio standards and proposed repeal of tax subsidies for oil and gas.[9] Again, there have been issues regarding EISA's funding and implementation.

The Emergency Economic Stabilization Act of 2008 (EESA)

As the global economy deteriorated throughout the summer and fall of 2008, Congress enacted and President George W. Bush signed into law on October 3, 2008, the Emergency Economic Stabilization Act of 2008, Pub. L. No. 110-343, 122 Stat. 3765 (2008) (hereinafter referred to as EESA). The EESA expanded and extended the production tax and investment tax credits for certain sources of renewable energy; created a new category of tax credit bonds to finance State and local government initiatives designed to reduce GHG emissions; expanded and extended tax credits for energy efficiency improvements; provided tax incentives for facilities

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[8] Policy Act of 2005: Summary and Analysis of Enacted Provisions, CRS Report for Congress (March 8, 2006).
[9] Energy Independence and Security Act of 2007: A Summary of Major Provisions, CRS Report for Congress (December 21, 2007).

that produce cellulosic biofuels; and expanded tax credits for biodiesel.[10] Enactment of these provisions during one of the most severe economic crisis in recent history, demonstrates the importance Congress places upon energy policy.

The American Recovery and Reinvestment Act of 2009 (ARRA)

On February 17, 2009 President Obama signed into law the American Recovery and Reinvestment Act of 2009, P.L. 111-5, 123 Stat. 115 (2009) (hereinafter referred to as ARRA). The ARRA provides $50 billion in support of new national renewable energy strategies, the electric grid, advanced vehicles, energy efficiency, and other aspects of energy, environment, climate change and sustainability. The ARRA provides critically needed funding for the energy policies previously enacted, and the new policies embodied in the ARRA.[11]

The ARRA expands tax incentives for new sources of renewable energy, including the production tax credit, investment tax credit, treasury grants and accelerated depreciation. The Act provides for direct spending in the areas of renewable energy and energy efficiency ($16.8 billion), modernization of the nation's electric grid ($11 billion), R&D and demonstration projects ($25 billion), and advanced battery grants ($2 billion). It also increases the authorization for Conservation and Renewable Energy Bonds by $1.6 billion; and, provides $6 billion additional funding for the Renewable Energy Loan Guaranty Program.[12]

III.
RENEWABLE PORTFOLIO STANDARDS

State RPSs

Renewable Portfolio Standards (RPSs) are being enacted by state legislatures across the country. An RPS is a requirement that an electric utility provide a specific percentage of its electricity from sources of renewable or alternative energy. These may include solar, wind, biomass, geothermal and hydro, as well as other energy efficiency technologies. State RPSs will vary in terms of what is included in the definition of renewable or alternative energy; the required percentage; the schedule for implementation; the entities regulated; and, the penalties assessed for failure to meet the RPSs. Currently 30 states and the District of Columbia have enacted some form of RPSs (Table 1).[13]

[See Table On Next Page]

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[10] CRS Summary H.R. 1424 (October 3, 2008).

[11] Energy Provisions in the American Recovery and Reinvestment Act of 2009 (P.L. 111-5), CRS Report for Congress (March 12, 2009).

[12] Overviews Renewable Energy Provisions American Recovery and Reinvestment Act of 2009, American Council on Renewable Resources.

[13] Understanding Energy in 2010: RECs, CERES, and Beyond, James M. Van Nostrand, ALI-ABA Telephone Services/Audio Webcast (December 16, 2009).

Table 1			
State	**Program Type**	**Percentage**	**Year**
Arizona	RPS	15%	2025
California	RPS	20%	2010
Colorado	RPS	20%*	2020
Connecticut	RPS	23%**	2020
Delaware	RPS	20%	2019
Florida	Goal	20%	-
Hawaii	RPS	40%	2030
Illinois	RPS	25%	2025
Iowa	RPS	105MW	-
Kansas	RPS	20%	2020
Maine	RPS	10%	2017
Maryland	RPS	20%	2022
Massachusetts	RPS	15%/7.1%/5.0%	2020/2009/2020
Michigan	RPS	10%+1100MW	2015
Minnesota	RPS	25%/30%	2025/2020
Missouri	RPS	15%	2021
Montana	RPS	15%	2015
Nevada	RPS	25%	2025
New Hampshire	RPS	23.8%	2025
New Jersey	RPS	22.5	2021
New Mexico	RPS	20%	2020
New York	RPS	24%***	2013
North Carolina	RPS	12.5%	2021
North Dakota	Goal	10%	2015
Ohio	AEPS	25%	2025
Oregon	RPS	25%*	2025
Pennsylvania	AEPS	18%	2020
Rhode Island	RPS	16%	2019
South Dakota	Goal	10%	2015
Texas	RPS	5880 MW	2015
Utah	Goal	20%	2025
Virginia	Goal	15%	2025
Washington	RPS	15%	2020
Washington, DC	RPS	20%	2020
West Virginia	AEPS	25%	2025
Wisconsin	RPS	10%	2015

*Colorado, North Carolina, Oregon and New Mexico have less stringent standards for certain municipalities, cooperative electric associations and/or smaller utilities.
**For Connecticut, an additional 4% is required from certain CHP and other energy efficiency measures.
***An additional 1% is expected from voluntary markets.

Indiana has not adopted a RPS, but legislation has been considered in previous sessions, and has been introduced in the current session.

In order to comply with these RPSs, a utility may invest funds in their own renewable energy facilities, purchase renewable energy from other providers, usually under long-term power purchase agreements (PPAs), or purchase renewable energy credits (RECs). Currently most utilities are meeting RPS requirements through the purchase of renewable energy under PPAs from independent power producers, developers and other electric providers. Regulated utilities, however, are now beginning to build their own renewable energy facilities. Trading of RECs is limited, making their value uncertain. The issue of who retains the RECs under a PPA, however, has become an important part of contract negotiations.

Federal RPS

Legislation also is pending in Congress which establishes a RPS. On the House side, the American Clean Energy and Security Act of 2009, H.R. 2454, 111th Cong. (2009), (known as ACES or the Waxman-Markey Bill) was passed on June 26, 2009. The legislation provides for a Combined Efficiency and Renewable Electricity Standard (CERES) for electrical retail suppliers. The electric provider is required to provide a specific percentage of its electricity from renewable energy sources or energy efficiency savings. Renewable energy targets are established and increased over time. (Table 2) Biomass fuels, such as those being considered for JMEP, are included in the definition of renewable energy resource.[14]

TABLE 2	
Calendar Year	**Required Annual Percentage**
2012	6.0
2013	6.0
2014	9.5
2015	9.5
2016	13.0
2017	13.0
2018	16.5
2019	16.5
2020	20.0
2021-2039	20.0

These targets may be met by using renewable energy sources or through energy efficiency. ACES permits up to 25% of the target to be met by energy efficiency. H.R. 2454, 111th Cong. §610(b)(3) (2009). State Governors may petition the Federal Regulatory Energy Commission to have the 25% energy efficiency cap raised to 40%. H.R. 2454, 111th Cong. §610(b)(4)(A) (2009). One federal renewable energy credit will be issued for each one megawatt hour of electricity generated from renewable sources. Electric providers will be required to establish compliance with the Federal RPS each year.

[14] *Id.*

On the Senate side, the American Clean Energy Leadership Act, S. 1462, 111th Cong. (2009), (ACELA) was passed out of the Senate Energy and Natural Resources Committee on June 17, 2009. The ACELA also establishes a Federal Renewable Electricity Standard for renewable energy and energy efficiency for regulated electric utilities. As with the ACES, specific percentages of a utilities' electricity must be provided from sources of renewable energy or energy efficiency. S. 1462, 111th Cong. §610(b)(1)(A),(B)(Table 3) (2009).[15]

TABLE 3	
Calendar Year	**Required Annual Percentage**
2012-2013	3.0
2014-2016	6.0
2017-2018	9.0
2019-2020	12.0
2021-2039	15.0

Renewable sources under the Senate bill also include the biomass fuels. The ACELA provides that these federal standards may be met by renewable energy and energy efficiency credits to be filed with the U.S. Department of Energy. S. 1462, 111th Cong. §610(c)(2), (i)(3), (4) (2009). In the alternative, compliance payments may be made by the electric provider. S. 1462 111th Cong. §610(b)(2)(A)-(D) (2009).[16]

There are significant differences between the ACES and the ACELA, notably the ACELA does not include cap-and-trade regulation. Considerable debate in the Senate is anticipated with any version of the ACELA passed by the Senate being referred to a Conference Committee for reconciliation with the provisions of the House's ACES. The significance of this pending federal legislation is that the Federal RPS will in all likelihood increase the demand for renewable energy, as will the State RPSs, increasing the market price for renewable energy.

IV.
RENEWABLE ENERGY CREDITS

RECs are tradable certificates reflecting the environmental attributes of a renewable energy facility, or the fact that the facility is capable of generating electricity from renewable fuels. Generally one megawatt hour of electricity equals one REC. A utility may purchase RECs to meet State RPS requirements, rather than investing funds in a facility capable of producing renewable energy, or purchasing the renewable energy from other sources.

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[15] *Id.*
[16] *Id.*

RECs Regional Tracking Systems

RECs will be carefully tracked by regional tracking systems. There have been five regional tracking systems already established:

- Midwest Renewable Energy Tracking System (M-RETS);[17]
- New England Power Pool – Generation Information System (NEPOOL-GIS);[18]
- Pennsylvania Jersey Maryland Independent System Operator – Generation Attribute Tracking System (PJM-GATS);[19]
- Western Renewable Energy Generation Information System (WREGIS);[20] and
- Electric Reliability Council of Texas (ERCOT).[21]

The North American Renewables Registry also tracks renewable energy generation in states not covered by one of the regional systems.[22] These tracking systems verify renewable energy generation at specific facilities for purposes of compliance with State RPSs. RECs are tracked over the life cycle of each certificate, recording trades, identifying the holder of certificates, and ensuring against double accounting.[23]

Midwest Renewable Energy Tracking System (M-RETS)

M-RETS serves the Midwest and includes the States of Illinois, Iowa, Minnesota, Montana, North Dakota, South Dakota, Wisconsin and the province of Manitoba. M-RETS works closely with the Midwest Independent System Operator (MISO) who operates the electric transmission grid for the Midwest.[24] Indiana does not presently participate in M-RETS, but is likely to become a member in the event that Indiana adopts an RPS.

In addition to the establishment of M-RETS, there are other important policy initiatives in the Midwest which are driving the development of new sources of renewable energy. These policy initiatives include the Midwest Greenhouse Gas Reduction Accord which was signed by Governors of six Midwestern states and the province of Manitoba in 2007; the Midwest Energy Infrastructure Accord which is part of the Midwest Governors Association's agenda; and, the Report of the Chicago Council on Global Affairs "Embracing the Future: the Midwest and a New National Energy Policy."[25] All of these initiatives and policy documents support the transition away from fossil fuels to renewable energy.

At this time it is difficult to place a value on RECs. It is clear that RECs will have a tangible monetized value reflecting the environmental attributes of renewable energy facilities,

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[17] M-RETS, Midwest Renewable Energy Tracking System, www.mrets.net (last visited Jan. 19, 2010).
[18] NEPOOL, www.nepoolgis.com (last visited Jan. 19, 2010).
[19] PJM Environmental Information Services, www.pjm-eis.com (last visited Jan. 19, 2010).
[20] WREGIS, Western Renewable Enegy Generation Information System, www.wregis.org (last visited Jan. 19, 2010).
[21] ERCOT, www.ercot.com, (last visited Jan. 19, 2010).
[22] North American Renewables Registry, http://narenewables.apx.com (last visited Jan. 19, 2010).
[23] M-RETS, Midwest Renewable Energy Tracking System, http://www.mrets.net/resources/Archives.asp (last visited Jan. 19, 2010).
[24] *Id.*
[25] The Midwest-Integrating State, Regional and Federal Climate and Energy Programs, Jeffery Fort, ALI-ABA Telephone/Audio Webcast (December, 2009).

but at this point little trading has occurred which establishes a market value in the Midwest. The right to RECs in the sale of electricity, however, has become an important issue in the negotiation of PPAs.

V.
FINANCIAL INCENTIVES

Federal income tax incentives have played an important role in the development of renewable energy facilities. Generally these incentives are in the form of tax credits taken against the taxpayer's income tax liability. The purpose of the incentives is to attract investments from private capital markets. These tax credits have been particularly effective in developing the wind industry, and now are playing an important role in the development of the solar industry.

Production Tax Credit (PTC)

A credit taken against the taxpayer's income tax liability based upon energy production. The EESA (October, 2008) and the ARRA (February, 2009) significantly expanded the eligibility and extended the required in-service dates for the PTC. Importantly, the ARRA allows the taxpayer who is eligible for the PTC to take the federal investment tax credit, or in the alternative, to receive a cash grant from the U.S. Treasury Department in lieu of the PTC.[26]

Investment Tax Credit (ITC)

A credit against taxpayer income tax liability based upon the amount of the investment in the renewable energy facility. The amount of the credit can be 30% of the qualifying costs depending upon the type of renewable fuel and technology. In other instances 10% of the amount invested qualifies for the credit. The EESA (October, 2008) and the ARRA (February, 2009) significantly expanded the eligibility and extends the in-service dates for the ITC. The ARRA provides that a taxpayer eligible for the ITC may receive a cash grant from the U.S. Treasury Department instead of taking the ITC for new facilities. Certain open or closed loop biomass systems now qualify for a 30% tax credit through the in-service date of December 31, 2013.[27]

Treasury Grants

The ARRA created a renewable energy grant program that is administered by the U.S. Department of Treasury (Treasury). A taxpayer eligible for the ITC may take this credit or receive a grant from Treasury instead of the ITC. The new law also allows taxpayers eligible for the PTC to receive the grant instead of taking the credit. The cash grant is in the amount of 30% of the basis of the eligible property for the renewable energy facility. Grants are available to eligible property placed in service in 2009 or 2010, or placed in service by a specific credit termination date, which varies with the type of renewable fuel, if construction is started in 2009

[26] DSIRE, Renewable Electricity Production Tax Credit, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US13F&re=ee=1&ee=1 (last visited Jan. 19, 2010).

[27] DSIRE, Business Energy Investment Tax Credit, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US02F&re=ee=1&ee=1 (last visited Jan. 19, 2010).

or 2010. The grants are disbursed within 60 days of the date of the grant application, or the date the property is placed in service, whichever is later.[28]

Accelerated Depreciation

Under the Modified Accelerated Cost-Recovery System (MACRS) investments in certain property may be recovered through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. Certain renewable energy technologies are classified as five year property, with the qualifying property being defined under the ITC statute. Certain biomass property has a class life of seven years under MACRS. Eligible biomass property generally includes assets used in the conversion of biomass to heat and electric power. In the past, certain eligible renewable energy property which met specific requirements was entitled to deduct 50% of the adjusted basis of the property in 2008 and 2009, with the remaining 50% of the adjusted basis depreciated over the ordinary depreciation schedule.[29]

The American Recovery and Reinvestment Act (ARRA) Grants

Congress through the ARRA appropriated $2.5 billion for renewable energy projects. Funds are being administered by the U.S. Department of Energy through their various energy programs. Most relevant to the JMEP are program funds being administered through the Office of Energy Efficiency and Renewable Energy. Grants are being made to local units of government through direct funding formulas (Block Grants) and through competitive grants. The grant application process is being administered through the federal grants program – FedConnect. Funding Opportunity Announcements (FOA) are routinely issued by FedConnect soliciting applications for renewable energy projects. Each FOA involves different projects or programs and has its own merit review criteria.[30]

Renewable Energy Production Incentive

Incentive payments for electricity generated and sold by a new qualifying renewable energy facility. Qualifying systems are eligible for payments of 1.5% per kilowatt hour in 1993 dollars (indexed for inflation) for the first 10-year period of operations, subject to the availability of annual appropriations. Eligible production facilities include government entities. Payments are made only for electricity generated from a qualifying facility first used prior to October 1, 2016. Appropriations have been authorized through fiscal year 2026. If there are insufficient appropriations to make full payments for electricity production from all qualifying facilities, the available funds are awarded on a pro rata basis.[31]

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[28] DSIRE, U.S. Department of Treasury – Renewable Energy Grants, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US53F&re=ee=1&ee=1 (last visited Jan. 19, 2010).
[29] DSIRE, Modified Accelerated Cost-Recovery System (MACRS) + Bonus Depreciation, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US06F&re=ee=1&ee=1 (last visited Jan. 19, 2010).
[30] American Recovery and Reinvestment Act of 2009, http://www.fedconnect.net/FedConnect/ (last visited Jan. 19, 2010).
[31] DSIRE, Renewable Energy Production Incentive (REP), http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US33F&re=ee=1&ee=1 (last visited Jan. 19, 2010).

Rural Energy Program for America (REAP)

A grant and loan guarantee program administered by the U.S. Department of Agriculture (USDA). The deadline for the last solicitation was July 31, 2009. Grants and loan guarantees are awarded for investments in renewable energy systems and feasibility studies. REAP promotes, among other things, renewable energy for agricultural producers and rural small businesses, with local governments being eligible to receive funding. Grants are limited to 25% of a proposed projects cost up to $25 million. At least 20% of the funds must be dedicated to grants of $20,000 or less. The USDA announces the availability of funding through Notice of Funds Availability.[32]

Clean Renewable Energy Bonds (CREBs)

Bonds used primarily by the public sector to finance renewable energy projects. CREBs are issued, theoretically, with a 0% interest rate. The borrower pays back only the principal on the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest. CREBs differ from traditional tax-exempt bonds, in that the tax credits available to the bondholder are treated as taxable income. The EESA and the ARRA significantly increase the total allocation of CREBs to $2.4 billion. The expiration date for new CREB allocations was August 4, 2009. It remains to be seen if the IRS will issue new funding announcements for CREBs.[33]

Qualified Energy Conservation Bonds (QECBs)

Bonds that may be used by local government to finance certain types of energy projects. QECBs are qualified tax credit bonds similar to CREBs. The EESA and ARRA expanded the allowable bond volume to $3.2 billion. Theoretically the interest rate on the bond is 0%, with the borrower paying only the principal on the bond, and the bondholder receiving federal tax credits in lieu of traditional bond interest. The definition of "Qualifying Energy Conservation Projects" is fairly broad, including projects involving renewable energy production. Renewable energy facilities that are eligible for CREBs are also eligible for QECBs.[34]

The significance of these tax incentives to the JMEP is access to the private capital markets, and lower cost public financing. These tax incentives have proven successful in the development of renewable energy facilities in certain sectors, most notably within the wind industry, and more recently in the solar industry. While the recent economic downturn and tightening credit markets have curtailed the usefulness of tax credits, there are recent indications of economic recovery and loosening of credit. The availability of these tax incentives may have a bearing on the Board's ability to access the private capital markets and to take advantage of a competitive market for project developers and investors.

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[32] DSIRE, USDA – Rural Energy for America (REAP) Grants, http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US05F&re=ee=1&ee=1 (last visited Jan. 19, 2010).

[33] DSIRE, Federal Incentives/Policies for Renewable Energy: Clean Renewable Energy Bonds (CREBs), http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US45F&re=1&ee=0 (last visited Jan. 21, 2010).

[34] DSIRE, Qualified energy Conservation Bonds (QECBs), http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US51F&re=ee=1&ee=1 (last visited Jan. 19, 2010).

VI.
CAP-AND-TRADE

The principal objective of all of these policy initiatives is to reduce GHG emissions. One of the approaches to reducing CO_2, the principal GHG emission of concern, is the much debated cap-and-trade. Under cap-and-trade, national target levels of the regulated emissions are set, and caps are imposed on individual sources which are designed to achieve the targeted levels. Each source is permitted for a specific number of allowances equal to its allowed emissions.

Allowances authorizing emissions are then allocated among sources, and limited in number to ensure the integrity of the national target levels. At the end of each year, every source must have enough allowances to cover its emissions for that year. Unused allowances, for those sources whose actual emissions are less than their caps, may be sold, traded, or saved (banked) for future use.

The concept is to allow for an economically efficient allocation of the costs associated with meeting CO_2 emission reductions. Each source has the opportunity to choose among alternatives that best meet its needs in complying with the emission caps. These alternatives include: installing pollution control equipment; switching to lower CO_2 emitting fossil fuels, such as natural gas; employing energy efficiency measures; using renewable fuels; buying excess allowances from other sources; or using a combination of these options.[35]

The cap-and-trade approach has been used by the Environmental Protection Agency in its Acid Rain Program which was adopted under Title IV of the 1990 Clean Air Act Amendments. SO_2 and NO_x emissions are subject to the caps. The number of allowances allocated to sources of these emissions are designed to meet the national targeted levels. The number of allowances decrease over time as the targeted levels for emissions decline. The Acid Rain Program has been quite successful with SO_2 emissions have decreasing by more than 30% from 1990 levels and NO_x emissions decreasing in the Northeast by 60% from 1990 levels. Costs of meeting targets also have been considerably lower than estimated.[36]

American Clean Energy and Security Act (ACES)

The ACES, the recent energy legislation enacted by the U.S. House of Representatives, establishes an economy wide CO_2 cap-and-trade program. The bill's cap-and-trade program, along with other incentives and standards for increased efficiency and low-carbon energy consumption, transforms the structure of energy production and consumption in the U.S. The share of primary energy provided by a low or zero-carbon sources of energy significantly increase. In terms of the cap-and-trade program in the bill, it is estimated that the price for allowances allocated to sources of GHG will trade at $13.00 per metric ton CO_2 equivalent in 2015 and $16.00 in 2020. The ACES also provides for domestic and international "carbon offsets," which are financial instruments designed to reduce GHG emissions and are also measured by CO_2 metric ton equivalents. A source of GHG emissions may invest in a domestic or international project resulting in GHG emissions reduction to offset its own emissions. This

[35] Cap-and-Trade, U.S. Environmental Protection Agency, http://epa.gov/captrade/ (last visited Jan. 19, 2010).
[36] Acid Rain Program, U.S. Environmental Protection Agency, http://epa.gov/airmarkets/progsregs/arp/index.html (last visited Jan. 19, 2010).

can be done for either mandatory compliance with CO_2 standards, or on a voluntary basis as a commitment to GHG emissions reduction. [37]

American Clean Energy Leadership Act (ACELA)

The ACELA, pending in the U.S. Senate, does not include a cap-and-trade program. Considerable debate in the Senate is anticipated. As Congress debates cap-and-trade, however, administrative regulations are being promulgated to regulate GHGs. The U.S. Supreme Court has held that the U.S. Environmental Protection Agency (EPA) may regulate GHG emissions. *Massachusetts v. EPA*, 549 U. S. 497 (2007). As a result, the EPA issued a proposed rule on September 30, 2009 which requires permits for large facilities emitting over 25,000 tons of GHGs to demonstrate use of the best practices and technology to minimize these emissions. The rule proposes new thresholds for GHG emissions that define when the Clean Air Act permits under New Source Review and Title V operating permits would be required for more construction or modifications to existing facilities.[38] Whether Congress or the EPA regulates GHG emissions is an important part of the cap-and-trade debate.

The significance of the anticipated cap-and-trade program is that it will result in higher costs for energy sources using fossil fuels, such as coal. The intended purpose is to transition from reliance on fossil fuels to greater use of renewable fuels. As the demand for renewable energy increases, so should the market price for electricity generated from sources using renewable fuels. This will have a favorable impact on future revenue streams from power sales from renewable energy facilities.

VII.
RENEWABLE ENERGY MARKETS

Annual Energy Outlook 2010 (AEO 2010)

On December 14, 2009 the Energy Information Agency (EIA) released its Annual Energy Outlook 2010 (AEO 2010) reference case. The EIA evaluates trends and issues impacting U.S. energy markets. The AEO 2010 reference case reflects current market conditions to the extent possible. The reference case assumes that current laws are unchanged and that sunset provisions in current laws will take effect ending current programs. The reference case does not consider legislation and regulations currently pending and which have a high probability of being enacted, nor does it consider that existing sunset provisions may be extended. The complete AEO 2010 report will include many additional cases which will assume the enactment of new policies and the extension of existing programs. [39]

[37] EPA Analysis of the American Clean Energy and Security Act of 2009 in the 111th Congress, U.S. Environmental Protection Agency, June 23, 2009, http://epa.gov/climatechange/economics/pdfs/HR2454_Analysis.pdf (last visited Jan. 19, 2010).
[38] Fact Sheet - Proposed Rule: Prevention of Significant Deterioration and Title V Greenhouse Tailoring Rule, http://www.epa.gov/NSR/fs20090930action.html (last visited Jan. 19, 2009).
[39] Annual Energy Outlook 2010 Early Release Overview, Energy Information Agency, http://www.eia.doe.gov/oiaf/aeo/pdf/overview.pdf (last visited Jan. 19, 2010).

The AEO 2010 projects that electric consumption will increase at an average annual rate of 1.0% from 2008 to 2035. The fossil fuel share of energy consumption falls from 84% of the total U.S. energy demand in 2008 to 78% in 2035, reflecting the changes in U.S. energy policy. The mix of investments in new power plants includes fewer coal fired plants than other technologies. Coal, however, remains the dominant energy source for electric generation because of continued reliance on the many existing coal fired plants and the necessary construction of new plants to meet rising base load demands. [40]

Natural gas will play a much larger role in the generation of electricity because of the growing concerns of GHG emissions. Gas fired plants are lower in GHG emissions and are much cheaper to build than coal or nuclear facilities. Natural gas supplies are expected to increase due to new extraction technologies and investments in oil production from shale fields.

Generation of electricity from renewable fuels increases significantly due to the changes in U.S. energy policies previously addressed, including state and potentially federal RPSs, federal tax incentives, ARRA funding, loan guarantee programs, low cost public financing, CO_2 regulation and anticipated cap-and-trade program. The AEO 2010 projects that the share of generation coming from renewable fuels will grow from 9% in 2008 to 17% in 2035. This is true even though the AEO 2010 reference case assumes federal subsidies expire as provided for by existing law. Any extension of these incentives could have substantial impact on renewable generation. [41]

<u>Market Uncertainty</u>

Unfortunately substantial uncertainty makes it difficult to forecast long term market prices for renewable energy. Among the many uncertainties are the extent to which U.S. energy policy will continue, or be reinforced by new legislative enactments. Renewable energy prices will no doubt be impacted by global initiatives to reduce GHG emissions, and U.S. commitments to these international goals.

Regardless of energy conservation, demand for electric power will likely continue to increase. On the supply side, existing nuclear plant licenses are likely to be renewed along with new construction of nuclear facilities. The likely development and commercialization of new clean coal technologies and carbon capture and sequestration also may impact the growth in renewable energy supplies.

VIII.
PROJECT FINANCE

Financing will be a critical part to the JMEP project. If the Board decides to extend the life of the facility for 25 years and continues coal as the fuel of choice, B&V estimates the required capital investment will be $10.9 million. In order to enable the facility to fire 20% biomass fuel, B&V estimates an additional $1.5 million investment. If the facility is upgraded to

[40] *Id.*
[41] *Id.*

fire 100% biomass fuel, B&V estimates the capital requirements will range from $40.0 to $46.4 million, depending upon the type of technology used.

Conventional Tax-Exempt Financing

The City could finance the project through conventional tax-exempt financing. This might take the form of general obligation, tax-backed, or revenue bonds, depending upon how the project is structured. There will be important constitutional and statutory limitations that will have to be considered. The City's debt capacity will have to be reviewed and potential rating agency action considered. The City also will have to take into consideration other competing capital needs.

Clean Renewable Energy Bonds (CREBs)

As discussed, Congress has provided the option of Clean Renewable Energy Bonds (CREBs), and has authorized an allowable bond volume of $2.4 billion. Theoretically the bond issuer pays no interest, and only principal payments are required. The bondholder receives credits against income tax liabilities in lieu of traditional tax-exempt interest payments. The bond issuer must apply to the Internal Revenue Service (IRS) for the approved CREB's allocations, and then issue the bonds within a specific period of time. In October 2009 the Department of Treasury announced allocations of $2.2 billion of CREBs which included 806 projects throughout the country. The extent to which the IRS will issue further notices regarding CREB allocations from the remaining $200 million allowable bond volume is uncertain, or whether Congress will provide for further CREBs authorizations. [42]

Qualified Energy Conservation Bonds (QECBs)

Congress has also provided the option to issue Qualified Energy Conservation Bonds (QECBs) which can be issued by local governments to finance renewable energy projects. The original volume limits for QECBs was $800 million, which was increased to $3.2 billion by ARRA. The bonds are similar to CREBs with interest rates intended to be zero percent to the issuers, with bondholders entitled to tax credits in lieu of interest payments. QECBs are not subject to prior approval by the IRS with allocations going directly to the states. Generally renewable projects eligible for CREBs are also eligible for QECBs. [43]

Private Capital Markets

The City may also access the private capital markets. The financial incentives available to private investors for investments in renewable energy facilities have created what is referred to as "tax equity financing". The recent economic downturn, however has greatly reduced the need for tax credits, and as a result limited tax equity financings. Assuming that credit markets return to normal, renewable energy financial incentives continue into the future, and opportunities exist for the investment community to realize sufficient returns on investment, there may be opportunities to finance upgrades to JMEP through private partnerships. Using private capital

[42] DSIRE, Federal Incentives/Policies for Renewable Energy: Clean Renewable Energy Bonds (CREBs), http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US45F&re=1&ee=0 (last visited Jan. 21, 2010).
[43] DSIRE, Qualified energy Conservation Bonds (QECBs), http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=US51F&re=ee=1&ee=1 (last visited Jan. 19, 2010).

markets, however, will cost the City more than traditional tax-exempt financing. This will be a trade off the City will have to address.

IX.
PUBLIC-PRIVATE PARTNERSHIPS

Project development may be approached in a number of ways. The City could develop the project itself by procuring design and construction services under more conventional public work statutes. This may involve initial design work, bidding construction services and overseeing the project with an owner's representative. In procuring construction services and managing the project itself, the City assumes the risk inherent to project development.

The City also can turn to private developers. The purpose of a private partnership in project development would be to seek creative engineering and technical solutions and different approaches to project financing.

A public-private partnership would involve the design and execution of a competitive procurement. There would be an expense in terms of professional services necessary to conduct the procurement process. The process would include the following steps:

1. Market Assessment;
2. Developer Solicitation;
3. Proposal Evaluation;
4. Project Award; and
5. Project Documentation.

Each of these steps is important to ensuring a fair and competitive procurement, and one that results in creative approaches to maximizing the value the City's asset.

Market Assessment

A market assessment involves the identification of potential project developers. A private market for energy facility developers has existed for many years, since a competitive electric industry began to evolve. There are utilities, unregulated subsidiaries of investor-owned utilities, independent power producers and project developers who are actively involved in developing renewable energy facilities, including wind, solar, hydro geothermal and biomass facilities. These project developers often partner with the investment community because of the income tax incentives discussed. Tax equity financing has been used particularly in the wind industry, and more recently in the solar industry. Currently there is some question as to how long these tax incentives may be available. Another problem is the current condition of credit markets. Many, however, believe that the future for tax equity financing looks promising.

Developer Solicitation

As part of the market assessment, the City may want to issue a "Request for Expression of Interest" (REI), or similar document, seeking to initiate dialogue between developers and the City prior to issuance of a solicitation for project development. The purpose would be to learn more about the level of interest among developers, their access to the investment community and credit markets, and issues associated with responding to the City's solicitation and preparing quality proposals. The process may simply consist of issuance of the REI and a conference with developers to address these issues.

Another important part of designing a procurement for a project developer is a thorough assessment of the City's objectives. This includes considering the engineering and technical parameters the City is willing to entertain; the different business models it is willing to accept; and the desired level of involvement in ownership, financing and operation of the facility. And finally, the City will have to assess the business risks it is willing to accept given the level of ownership, financing and operation in which it wants to be involved. And finally, the City will have to assess the business risks it is willing to accept in terms of long-term fuel supplies, price volatility in the electric markets, facility performance and credit worthiness of its partner. All of these are important considerations that must be part of designing a project solicitation.

In developing the project solicitation, the City will have to carefully review Indiana statutes regarding the construction of public works projects. The City will want to design a procurement which provides the greatest flexibility to project developers in their proposals. There are a number of different approaches under Indiana statutes to develop the project. Ind. Code § 36-1-12, which is commonly referred to as "Design-Bid-Build", requires that plans and specifications for a project be completed prior to soliciting bids. Under Ind. Code § 5-30, the "Design-Build" delivery method provides that the project may be awarded to a single entity that is responsible for both the design and construction of the project. Factors other than costs may be considered in selecting the project developer. Ind. Code § 36-1-12.5 is the guaranteed savings contract statute which affords greater flexibility if the implementation of energy efficient measures. And finally, even greater flexibility may be afforded under Ind. Code § 5-23-1, which permits a political subdivision to enter into a public-private agreement with a project developer for the design, construction, operation, management, maintenance or financing of a public facility. These statutory considerations will be important to designing the procurement process and developing the project solicitation.

Proposal Evaluation

The proposal evaluation process is obviously one of the most important aspects of procuring a project developer. While the City will want to give the project developer maximum flexibility in preparing proposals, it will want to give enough guidance to proponents that proposals will meet the City objectives. Measuring the extent to which proposals meet those objectives will require evaluation on an "apples to apples" basis. The evaluation must be fair, give the developer notice of the City's objectives and the relative weight to be given, and a clear description of the procurement process from issuance of the RFP, to award of the project, and negotiation of the final legal documents. The evaluation process will entail an engineering and technical parameter, an economic analysis and a careful review of the allocation of business risks between the developer and the City.

Project Award

There are also different approaches to awarding the project. The project may be awarded to a single developer with contract negotiations following. The City may also short list the developers, and then negotiate best and final offers with each. The City may go as far as to selecting a short list of developers and actually negotiating the legal agreements necessary to project development. While a more expensive approach, this does clearly define the allocation of all business risks between the parties.

Project Documentation

The final stage of the procurement will be the development of the legal agreements supporting the project. There may be an agreement with owners' representatives, fuel supply agreements, power purchase agreements, utility interconnection agreements, design and construction agreements, long-term management and operation agreements, and auxiliary agreements necessary to the project. In addition, there may be regulatory matters associated with electric sales and interconnection of the facility to the electric grid.

X.
JMEP DECISION

The Board's decision regarding JMEP's future is not an easy one. The City owns what historically has been a critically important asset to the City's municipal electric utility. It is now under utilized because of the City's participation in the Indiana Municipal Power Agency (IMPA) and its "all requirements" agreement. Currently the City is unable to profitably operate the facility due to higher coal prices and low electric prices in the spot market. At the current staffing levels, the city is losing money, regardless of capacity payments being made by IMPA. The City has agreed to provide IMPA with available capacity until May 31, 2011. In addition, the City also may have additional commitments under its coal contract.

Based upon the B&V and Bingham Report, it appears the City has the following options:

JMEP Sale

B&V estimates the "as-is" market value of the facility to be $6.7 million dollars based upon a cost approach. It estimates the "as-in" market value based upon an income approach at a negative $4.6 million dollars. In all likelihood, any potential purchaser will look at the facility from its income potential. Consequently, the sale of JMEP on an "as is" basis may be difficult.

JMEP Decommissioning

The City could proceed with decommissioning of JMEP and using the real estate for other purposes or sale. This would entail dismantling the facility, attempting to secure scrap value for major components, and disposing of the balance of the facility. B&V estimates the scrap value at $375,000. B&V's scrap value does not include the cost of decommissioning and any remediation required due to contamination issues. Decommissioning could be a substantial expense to the City.

Life Extension Improvements

The City may make capital improvements to JMEP to extend the life of the facility by 25 years at an estimated cost of $10.9 million. Assuming JMEP continued to fire 100% coal, B&V's base case estimates the market value of JMEP at a negative $12.1 million dollars. Assuming 10% higher prices for the sale of the electric output, B&V estimates the market value at a negative $1.6 million. Assuming the fuel prices are 10% higher, the estimated market value is a negative $19.8 million. Based upon these estimated market values, the prudency of making the required capital investment necessary to extend the life of the facility appears questionable.

Co-Firing Biomass

B&V estimates the capital cost of upgrading JMEP to make it capable of co-firing 20% biomass fuel is $1.5 million. Based only on fuel savings, B&V estimates operating savings to be $360,000 per year. This does not include any premium on the price paid for electricity produced by co-firing 20% renewable fuel, or any value associated with facility RECs. On this basis, B&V concludes that co-firing biomass may provide an attractive opportunity. Based upon Bingham's report on renewable energy policies, carbon regulation, and trends in the renewable energy markets, the economic outlook for renewable facilities appears to be relatively good. There, however, are considerable uncertainties.

100% Biomass

The City could consider upgrading the facility to enable it to fire 100% biomass fuel. B&V estimates a required capital investment to be in the range of $40.0 million and $46.4 million, depending upon the technology used. These estimates assume a total boiler replacement and a new transmission line and substation, but utilizing the existing steam turbine generator and balance of plant. B&V's estimates are based upon using 100% green wood with a 50% moisture content and 4,500 Btu per ton heat content. Based upon the relatively high capital costs, the premiums paid for renewable energy would have to be exceptional to make the economics of this option work.

Renewable Energy Market Price Forecasts

The City could proceed by completing market forecasts for renewable energy and a valuation of RECs. The substantial uncertainties, however, will make the accuracy of any such forecasts subject to a significant margin of error. It may provide, however, additional support for a decision to move forward with the biomass options.

Public-Private Partnerships

The City could solicit proposals to develop JMEP as a renewable energy facility. The purpose of a public-private partnership would be to tap the creativity of the marketplace in terms of engineering and technical solutions and project financing. The market for project developers and investors appears to be reasonably competitive, with the caveat that credit markets are still tight and there continues to be uncertainty regarding the extent to which financial incentives will continue. Designing and executing a procurement for a project developer will require additional expenditures by the City.

Steam or Chilled Water

Facility	Sq. Ft.	Load Profiles Heating Dtherm/yr	Load Profiles Cooling Tons/yr	Steam Pressure	Steam Temp	Cost Heating $/1000lb Stm	Cost Cooling $/ton CHW
City Hall (NG)		820					
County Court House (NG)		1545					
Kimball - 15th & Cherry	584693						
MasterBrand - 15th Street							

Biomass

Supplier	Fuel Type	Tons/mo	$/ton	Btu/lb	% Moisture	% Ash	Chemistry (%)					
							Carbon	Hydrogen	Oxygen	Nitrogen	Sulfur	Chlorine
MasterBrand - Plant 2	Sawdust	5		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
MasterBrand - Plant 22	Sawdust	520		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
MasterBrand - Plant 3	Sawdust	111		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
MasterBrand - Plant 4	Sawdust	76		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
MasterBrand - Plant 5	Sawdust	614		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
Kimball - 15th St.	Sawdust	58		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
Kimball - Cherry St.	Sawdust	166		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
Kimball - 11th Ave.	Sawdust	25		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
Kimball - 16th St.	Sawdust	12		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
Kimball - Santa Claus	Sawdust	121		8000	5.75	0.8	50	6.15	40.6	2.45	0.19	
Kimball - General	Skids	11										
Jasper Group	Scraps	25										
Indiana Furniture - Plywood	Scraps	37	-44									
Indiana Furniture - Jasper	Scraps	38	-44									
Indiana Furniture - Dubois	Scraps	6	-44									
Dubois Wood	Scraps	40										
Dubois Wood	Sawdust	20										
Best Chairs	Shavings	240	10									
Total		2125										

LAB NO. 2007-2567-1

DATE REC'D 09/13/07

TE SAMPLED --------

SAMPLED BY CLIENT

STANDARD LABORATORIES, INC.

1530 N. Cullen Avenue
Evansville, IN 47715

KIMBALL INTERNATIONAL, INC.
CORPORATE ENVIRONMENTAL GROUP
1600 ROYAL ST
JASPER, IN 47549
Attn: Ron Rothgerber

SAMPLE IDENTIFICATION

11th Ave - 1
Sawdust/Wood Fuel
9/13/2007

DATE REPORTED: 09/14/07

te: Sample Tested using ASTM Volume 05.06 for Gaseous Fuels; Coal and Coke

	% MOISTURE	% ASH	% VOLATILE	% FIXED CARBON	BTU/LBS	% SULFUR
AS REC'D	6.06	0.68	XXXX	XXXX	7834	0.06
DRY BASIS	------	0.72	XXXX	XXXX	8339	0.06
M-A-FREE					8399	

NOTE: XXXX INDICATES ANALYSIS WAS NOT REQUESTED

Respectfully Submitted

FORM # 21

LAB NO.	2008-1559-3
DATE REC'D	11/17/08
DATE SAMPLED	--------
SAMPLED BY	CLIENT

STANDARD LABORATORIES, INC.

1530 N. Cullen Avenue
Evansville, IN 47715

KIMBALL INTERNATIONAL, INC.
CORPORATE ENVIRONMENTAL GROUP
1600 ROYAL ST
JASPER, IN 47549
Attn: RON ROTHGERBER

SAMPLE IDENTIFICATION

15th St.-1
SAWDUST/WOOD FUEL
03:00 PM
11/14/08

DATE REPORTED: 11/24/08

Note: Sample Tested using ASTM Volume 05.06 for Gaseous Fuels; Coal and Coke

	% MOISTURE	% ASH	% VOLATILE	% FIXED CARBON	BTU/LBS	% SULFUR
AS REC'D	5.09	1.00	XXXX	XXXX	7985	0.29
DRY BASIS	------	1.05	XXXX	XXXX	8413	0.31
M-A-FREE					8502	

NOTE: XXXX INDICATES ANALYSIS WAS NOT PERFORMED

Respectfully Submitted

FORM # 21

LAB NO. 2008-1559-1

DATE REC'D 11/17/08

DATE SAMPLED --------

SAMPLED BY CLIENT

STANDARD LABORATORIES, INC.

1530 N. Cullen Avenue
Evansville, IN 47715

KIMBALL INTERNATIONAL, INC.
CORPORATE ENVIRONMENTAL GROUP
1600 ROYAL ST
JASPER, IN 47549
Attn: RON ROTHGERBER

SAMPLE IDENTIFICATION

16th St.-1
SAWDUST/WOOD FUEL
10:00 AM
11/17/08

DATE REPORTED: 11/24/08

Note: Sample Tested using ASTM Volume 05.06 for Gaseous Fuels; Coal and Coke

	% MOISTURE	% ASH	% VOLATILE	% FIXED CARBON	BTU/LBS	% SULFUR
AS REC'D	5.33	0.82	XXXX	XXXX	8056	0.26
DRY BASIS	------	0.87	XXXX	XXXX	8510	0.27
M-A-FREE					8585	

NOTE: XXXX INDICATES ANALYSIS WAS NOT PERFORMED

Respectfully Submitted ____________________

FORM # 21

LAB NO. 2008-1559-2

DATE REC'D 11/17/08

DATE SAMPLED --------

SAMPLED BY CLIENT

STANDARD LABORATORIES, INC.

1530 N. Cullen Avenue
Evansville, IN 47715

KIMBALL INTERNATIONAL, INC.
CORPORATE ENVIRONMENTAL GROUP
1600 ROYAL ST
JASPER, IN 47549
Attn: RON ROTHGERBER

SAMPLE IDENTIFICATION

CHERRY ST.-1
SAWDUST/WOOD FUEL
10:00 AM
11/17/08

DATE REPORTED: 11/24/08

Note: Sample Tested using ASTM Volume 05.06 for Gaseous Fuels; Coal and Coke

	% MOISTURE	% ASH	% VOLATILE	% FIXED CARBON	BTU/LBS	% SULFUR
AS REC'D	5.12	0.73	XXXX	XXXX	7923	0.16
DRY BASIS	------	0.77	XXXX	XXXX	8351	0.17
M-A-FREE					8416	

NOTE: XXXX INDICATES ANALYSIS WAS NOT PERFORMED

Respectfully Submitted

FORM # 21

STANDARD LABORATORIES, INC.

Santa Claus

1530 N. Cullen Avenue, Evansville, IN 47715

FOR:
KIMBALL INTERNATIONAL
KIMBALL INDUSTRIAL PARK
WEST 12TH AVE.
JASPER, IN 47549
ATTN: RON ROTHGERBER

SAMPLE IDENTIFICATION:
HERITAGE HILLS
PLANT 1
SAMPLE 1
NOTE: Methods for coal may not apply to this matrix.

LAB NO.: 1999-753-2
DATE REC'D: 10/07/99
DATE SAMPLED: --------
SAMPLED BY: CLIENT

DATE REPORTED: 12/06/99

PROXIMATE ANALYSIS

	(% AS RECD)	(% DRY)
MOISTURE	6.70	
ASH	0.68	0.73
VOLATILE	73.21	78.47
FIXED CARBON	19.41	20.80
SULFUR	0.15	0.16
BTU/LB	8105	8687
M-A-FREE		8751

EQUILIBRIUM MOISTURE: XXXX

FREE SWELLING INDEX: 0

ASH FUSION TEMPERATURES (DEG F)

	REDUCING	OXIDIZING
INITIAL	2341	2409
SOFTENING	2375	2458
HEMISPHERICAL	2389	2481
FINAL	2414	2518

HARDGROVE GRINDABILITY INDEX (HGI)

XXXX AT XXXX % MOISTURE

MINERAL ANALYSIS OF ASH

	(% IGNITED BASIS)
SILICON DIOXIDE	10.72
ALUMINUM OXIDE	1.17
TITANIUM DIOXIDE	9.28
CALCIUM OXIDE	18.42
POTASSIUM OXIDE	7.29
MAGNESIUM OXIDE	3.99
SODIUM OXIDE	17.18
PHOSPHORUS PENTOXIDE	0.97
FERRIC OXIDE	1.51
SULFUR TRIOXIDE	0.40
BARIUM OXIDE	0.68
MANGANESE DIOXIDE	1.34
STRONTIUM OXIDE	0.18
UNDETERMINED	26.87

BASE/ACID RATIO: 2.2858
LBS ASH/MM BTU: 0.84
SLAG VISCOSITY: XXXX DEG F. T250 POISE
FOULING INDEX: XXXX TYPE: XXXX
SLAGGING INDEX: XXXX TYPE: XXXX
SILICA VALUE: 30.95
% ALKALI AS Na2O: 0.1609

ULTIMATE ANALYSIS

	(% DRY BASIS)
ASH	0.73
HYDROGEN	6.15
CARBON	49.84
NITROGEN	2.96
SULFUR	0.16
OXYGEN	40.16

CHLORINE XXXX

FLUORINE XXXX

FORMS OF SULFUR

	(% DRY BASIS)
TOTAL	XXXX
PYRITIC	XXXX
SULFATE	XXXX
ORGANIC	XXXX

ALKALIES (% DRY BASIS)

	ACID SOLUBLE	WATER SOLUBLE
SODIUM OXIDE	XXXX	XXXX
POTASSIUM OXIDE	XXXX	XXXX

Respectfully Submitted,

JW Snider

JUDITH W. SNIDER

STANDARD LABORATORIES, INC.

Santa Claus

1530 N. Cullen Avenue, Evansville, IN 47715

FOR:
KIMBALL INTERNATIONAL
KIMBALL INDUSTRIAL PARK
WEST 12TH AVE.
JASPER, IN 47549
ATTN: RON ROTHGERBER

SAMPLE IDENTIFICATION:
KEN SICARD
SAWDUST Sample #2

NOTE: Methods for coal may not apply to this matrix.

LAB NO.: 1999-753-1
DATE REC'D: 10/07/99
DATE SAMPLED: --------
SAMPLED BY: CLIENT

DATE REPORTED: 12/06/99

PROXIMATE ANALYSIS

	(% AS RECD)	(% DRY)
MOISTURE	6.53	
ASH	1.16	1.24
VOLATILE	73.72	78.87
FIXED CARBON	18.59	19.89
SULFUR	0.19	0.20
BTU/LB	8094	8659
M-A-FREE		8768

EQUILIBRIUM MOISTURE: XXXX

FREE SWELLING INDEX: 0

ASH FUSION TEMPERATURES (DEG F)

	REDUCING	OXIDIZING
INITIAL	2140	2400
SOFTENING	2194	2448
HEMISPHERICAL	2225	2469
FINAL	2260	2495

HARDGROVE GRINDABILITY INDEX (HGI)

XXXX AT XXXX % MOISTURE

MINERAL ANALYSIS OF ASH

	(% IGNITED BASIS)
SILICON DIOXIDE	28.44
ALUMINUM OXIDE	6.01
TITANIUM DIOXIDE	0.79
CALCIUM OXIDE	32.31
POTASSIUM OXIDE	4.38
MAGNESIUM OXIDE	3.73
SODIUM OXIDE	7.09
PHOSPHORUS PENTOXIDE	1.20
FERRIC OXIDE	6.39
SULFUR TRIOXIDE	0.51
BARIUM OXIDE	1.17
MANGANESE DIOXIDE	1.05
STRONTIUM OXIDE	0.21
UNDETERMINED	6.72

BASE/ACID RATIO:	1.5295		
LBS ASH/MM BTU:	1.43		
SLAG VISCOSITY:	XXXX	DEG F. T250 POISE	
FOULING INDEX:	XXXX	TYPE:	XXXX
SLAGGING INDEX:	XXXX	TYPE:	XXXX
SILICA VALUE:	40.13		
% ALKALI AS Na_2O:	0.1241		

ALKALIES (% DRY BASIS)

	ACID SOLUBLE	WATER SOLUBLE
SODIUM OXIDE	XXXX	XXXX
POTASSIUM OXIDE	XXXX	XXXX

ULTIMATE ANALYSIS

	(% DRY BASIS)
ASH	1.24
HYDROGEN	6.06
CARBON	49.63
NITROGEN	2.76
SULFUR	0.20
OXYGEN	40.11
CHLORINE	XXXX
FLUORINE	XXXX

FORMS OF SULFUR

	(% DRY BASIS)
TOTAL	XXXX
PYRITIC	XXXX
SULFATE	XXXX
ORGANIC	XXXX

Respectfully Submitted, J W Snider
JUDITH W. SNIDER

FORM NO. 20

STANDARD LABORATORIES, INC.

Cherry St.

1530 N. Cullen Avenue, Evansville, IN 47715

FOR:
KIMBALL INTERNATIONAL
KIMBALL INDUSTRIAL PARK
WEST 12TH AVE.
JASPER, IN 47549
ATTN: RON ROTHGERBER

SAMPLE IDENTIFICATION:
JASPER LAMINATONS
SAWDUST
SAMPLE 3
NOTE: Methods for coal may not apply to this matrix.

LAB NO.: 1999-753-3
DATE REC'D: 10/07/99
DATE SAMPLED: --------
SAMPLED BY: CLIENT

DATE REPORTED: 12/06/99

PROXIMATE ANALYSIS

	(% AS RECD)	(% DRY)
MOISTURE	6.29	
ASH	0.65	0.69
VOLATILE	74.87	79.90
FIXED CARBON	18.19	19.41
SULFUR	0.17	0.18
BTU/LB	8113	8658
M-A-FREE		8718

EQUILIBRIUM MOISTURE: XXXX

FREE SWELLING INDEX: 0

ASH FUSION TEMPERATURES (DEG F)

	REDUCING	OXIDIZING
INITIAL	2229	2563
SOFTENING	2280	2580
HEMISPHERICAL	2343	2590
FINAL	2360	2600

HARDGROVE GRINDABILITY INDEX (HGI)

XXXX AT XXXX % MOISTURE

MINERAL ANALYSIS OF ASH

	(% IGNITED BASIS)
SILICON DIOXIDE	11.70
ALUMINUM OXIDE	1.96
TITANIUM DIOXIDE	0.75
CALCIUM OXIDE	21.36
POTASSIUM OXIDE	8.45
MAGNESIUM OXIDE	4.83
SODIUM OXIDE	15.09
PHOSPHORUS PENTOXIDE	2.00
FERRIC OXIDE	2.04
SULFUR TRIOXIDE	0.45
BARIUM OXIDE	0.90
MANGANESE DIOXIDE	1.43
STRONTIUM OXIDE	0.23
UNDETERMINED	28.81

BASE/ACID RATIO: 3.5926
LBS ASH/MM BTU: 0.80
SLAG VISCOSITY: XXXX DEG F. T250 POISE
FOULING INDEX: XXXX TYPE: XXXX
SLAGGING INDEX: XXXX TYPE: XXXX
SILICA VALUE: 29.30
% ALKALI AS Na2O: 0.1430

ALKALIES (% DRY BASIS)

	ACID SOLUBLE	WATER SOLUBLE
SODIUM OXIDE	XXXX	XXXX
POTASSIUM OXIDE	XXXX	XXXX

ULTIMATE ANALYSIS

	(% DRY BASIS)
ASH	0.69
HYDROGEN	6.33
CARBON	50.11
NITROGEN	2.54
SULFUR	0.18
OXYGEN	40.15
CHLORINE	XXXX
FLUORINE	XXXX

FORMS OF SULFUR

	(% DRY BASIS)
TOTAL	XXXX
PYRITIC	XXXX
SULFATE	XXXX
ORGANIC	XXXX

Respectfully Submitted, JW Snider

JUDITH W. SNIDER

FORM NO. 20

STANDARD LABORATORIES, INC.

Cherry St.

1530 N. Cullen Avenue, Evansville, IN 47715

FOR:
KIMBALL INTERNATIONAL
KIMBALL INDUSTRIAL PARK
WEST 12TH AVE.
JASPER, IN 47549
ATTN: RON ROTHGERBER

SAMPLE IDENTIFICATION:
RECOVERED FROM JASPER LAMINATONS
WOODCHIPS FEB 5, 1999
SAMPLE 4
NOTE: Methods for coal may not apply to this matrix.

LAB NO.:	1999-753-4
DATE REC'D:	10/07/99
DATE SAMPLED:	--------
SAMPLED BY:	CLIENT
DATE REPORTED:	12/06/99

PROXIMATE ANALYSIS

	(% AS RECD)	(% DRY)
MOISTURE	5.55	
ASH	0.69	0.73
VOLATILE	77.29	81.83
FIXED CARBON	16.47	17.44
SULFUR	0.18	0.19
BTU/LB	8352	8843
M-A-FREE		8908

EQUILIBRIUM MOISTURE: XXXX

FREE SWELLING INDEX: 0

ASH FUSION TEMPERATURES (DEG F)

	REDUCING	OXIDIZING
INITIAL	2420	2459
SOFTENING	2450	2497
HEMISPHERICAL	2487	2515
FINAL	2514	2536

HARDGROVE GRINDABILITY INDEX (HGI)

XXXX AT XXXX % MOISTURE

MINERAL ANALYSIS OF ASH

	(% IGNITED BASIS)
SILICON DIOXIDE	14.12
ALUMINUM OXIDE	2.87
TITANIUM DIOXIDE	0.74
CALCIUM OXIDE	25.96
POTASSIUM OXIDE	10.96
MAGNESIUM OXIDE	4.78
SODIUM OXIDE	9.04
PHOSPHORUS PENTOXIDE	1.79
FERRIC OXIDE	4.41
SULFUR TRIOXIDE	0.48
BARIUM OXIDE	0.73
MANGANESE DIOXIDE	1.40
STRONTIUM OXIDE	0.25
UNDETERMINED	22.47

BASE/ACID RATIO:	3.1105	
LBS ASH/MM BTU:	0.83	
SLAG VISCOSITY:	XXXX	DEG F. T250 POISE
FOULING INDEX:	XXXX	TYPE: XXXX
SLAGGING INDEX:	XXXX	TYPE: XXXX
SILICA VALUE:	28.66	
% ALKALI AS Na2O:	0.1194	

ULTIMATE ANALYSIS

	(% DRY BASIS)
ASH	0.73
HYDROGEN	6.09
CARBON	49.63
NITROGEN	1.55
SULFUR	0.19
OXYGEN	41.81
CHLORINE	XXXX
FLUORINE	XXXX

FORMS OF SULFUR

	(% DRY BASIS)
TOTAL	XXXX
PYRITIC	XXXX
SULFATE	XXXX
ORGANIC	XXXX

ALKALIES (% DRY BASIS)

	ACID SOLUBLE	WATER SOLUBLE
SODIUM OXIDE	XXXX	XXXX
POTASSIUM OXIDE	XXXX	XXXX

Respectfully Submitted, JW Snider
JUDITH W. SNIDER

FORM NO. 20

REPORT ON

RENEWABLE ENERGY MARKETS

Prepared for

THE CITY OF JASPER

Prepared by

BINGHAM McHALE LLP

January ____, 2010

I.
INTRODUCTION

The purpose of this Renewable Energy Market Report is to provide the Jasper Electric Utilities Board (Board) with an expanded factual context for its decision regarding future investment in the Jasper Municipal Electric Plant (JMEP or Facility). The Board's decision will be driven by economics, including, the amount of capital investment necessary to upgrade and make the Facility capable of firing renewable fuels; operating expenses; a future revenue stream from the sale of electricity; value of Renewable Energy Credits (RECs); and, other factors, such as jobs, electric reliability and reduction in greenhouse gas (GHG) emissions. The value of the future income stream from electric sales (commodity) may be enhanced by the Facility's ability to fire renewable fuels, including wood wastes, turkey and poultry litter, corn stoves and other agricultural by-products. There also may be added value created by the RECs which are intended to reflect the Facility's use of renewable fuels (environmental attributes).

While precise market prices for renewable energy are not available at this time due to many uncertainties, this report will address current and anticipated energy policies, regulations, electric markets, project financing and public-private partnerships. The report is divided into nine sections:

- Introduction
- U.S. Energy Policies
- Renewable Portfolio Standards
- Renewable Energy Credits
- Cap-in-Trade
- Federal Tax Incentives
- Market Price Forecasts
- Project Financing
- Public-Private Partnership

The report will supplement the "Plant Condition Assessment Study" prepared by Black & Veach (B&V Report), and provide the Board with a broader factual context within which to make future decisions regarding the Facility.

II.
U.S. ENERGY POLICIES

Current U.S. energy policy is designed to reduce the consumption of electricity; reduce GHG emissions and other pollution from the generation of electricity; lessen the reliance on fossil fuels and increase the use of renewable fuels; reduce the reliance on foreign sources of energy; create new jobs within the energy sector; and, improve national security. While these policy initiatives began as early as the 1970s following the energy crisis of the Carter years, current efforts to transition from fossil fuels to domestic renewable fuels and alternative energy began in earnest in 2005.

The Energy Policy Act of 2005 (P.L. 109-58, hereinafter referred to as EPA) was signed into law on August 8, 2005 by President Bush. The EPA is intended to address the increasingly difficult issues relating to the nation's consumption of energy and the nature of our energy supplies. The Act's major provisions include:

- Tax breaks for energy conservation improvements
- Subsidies for renewable and alternative sources of energy
- Loan guarantees for innovative technologies
- Support for clean coal initiatives
- Support for advanced nuclear reactor designs
- Increases in the amount of bio-fuels to be mixed with gasoline
- Federal reliability standards for the nation's electric transmission grid
- Reports by the U.S. Department of Energy (DOE) regarding natural energy resources and demand-side management[1]

While the Act was hailed as a major energy policy initiative, there have been considerable issues with funding and timely implementation.

The Energy Independence and Security Act of 2007 (EISA) (P.L. 110-140, hereinafter referred to as EISA) was signed into law on December 19, 2007. The EISA is an omnibus energy policy law intended to increase energy efficiency and the availability of renewable energy. Key provisions include corporate average fuel economy standards for fleets of cars and light trucks by model year 2020; expanded requirements for renewable fuel standards applicable to blended gasoline; and, appliance and lighting efficiency standards. Two controversial provisions were not included in the enacted law, which related to renewable energy portfolio standards and proposed repeal of tax subsidies for oil and gas.[2] Again, there have been issues regarding EISA's funding and implementation.

As the global economy deteriorated throughout the summer and fall of 2008, Congress enacted and President Obama signed into law on October ___, 2009, the Emergency Economic and Stabilization Act of 2008 (P.L. 110-343, hereinafter referred to as EESA). The EESA expanded and extended the production tax and investment tax credits for certain sources of renewable energy; created a new category of tax credit bonds to finance State and local government initiatives designed to reduce GHG emissions; expanded and extended tax credits for energy efficiency improvements; provided tax incentives for facilities that produce cellulosic biofuels; and expanded tax credits for biodiesel.[3] Enactment of these provisions during one of the most severe economic crisis in recent history, demonstrates the importance Congress and this Administration places upon energy policy.

On February 17, 2009 President Obama signed into law the American Recovery and Reinvestment Act of 2009 (P.L. 111-5, hereinafter referred to as ARRA). The ARRA provides

[1] Need footnote
[2] Need footnote
[3] Need footnote

$50 billion in support of new national renewable energy strategies, the electric grid, advanced vehicles, energy efficiency, and other aspects of energy, environment, climate change and sustainability. The ARRA provides critically needed funding for the energy policies previously enacted, and the new policies embodied in the ARRA.[4]

The ARRA expands tax incentives for new sources of renewable energy, including the production tax credit, investment tax credit, treasury grants and accelerated depreciation. The Act provides for direct spending in the areas of renewable energy and energy efficiency ($16.8 billion), modernization of the nation's electric grid ($11 billion), R&D and demonstration projects ($25 billion), advanced battery grants ($2 billion). It also increases the authorization for Conservation and Renewable Energy Bonds by $1.6 billion; and, provides $6 billion additional funding for the Renewable Energy Loan Guaranty Program[5].

III.
RENEWABLE PORTFOLIO STANDARDS

Renewable Portfolio Standards (RPSs) are being enacted by state legislatures across the country. An RPS is a requirement that an electric utility provide a specific percentage of its electricity from sources of renewable or alternative energy. These may include solar, wind, biomass, geothermal and hydro. State RPSs will vary in terms of what is included in the definition of renewable or alternative energy; the required percentage; the schedule for implementation; the entities regulated; and, the penalties assessed for failure to meet the RPSs. Currently 30 states and the District of Columbia have enacted some form of RPSs (Table 1).[6]

Table 1

State	Program Type	Percentage	Year
Arizona	RPS	15%	2025
California	RPS	20%	2010
Colorado	RPS	20%*	2020
Connecticut	RPS	23%**	2020
Delaware	RPS	20%	2019
Florida	Goal	20%	-
Hawaii	RPS	40%	2030
Illinois	RPS	25%	2025
Iowa	RPS	105MW	-
Kansas	RPS	20%	2020
Maine	RPS	10%	2017
Maryland	RPS	20%	2022
Massachusetts	RPS	15%/7.1%/5.0%	2020/2009/2020
Michigan	RPS	10%+1100MW	2015
Minnesota	RPS	25%/30%	2025/2020

[4] Need footnote
[5] Need footnote
[6] Need footnote

State	Program Type	Percentage	Year
Missouri	RPS	15%	2021
Montana	RPS	15%	2015
Nevada	RPS	25%	2025
New Hampshire	RPS	23.8%	2025
New Jersey	RPS	22.5	2021
New Mexico	RPS	20%	2020
New York	RPS	24%***	2013
North Carolina	RPS	12.5%	2021
North Dakota	Goal	10%	2015
Ohio	AEPS	25%	2025
Oregon	RPS	25%*	2025
Pennsylvania	AEPS	18%	2020
Rhode Island	RPS	16%	2019
South Dakota	Goal	10%	2015
Texas	RPS	5880 MW	2015
Utah	Goal	20%	2025
Virginia	Goal	15%	2025
Washington	RPS	15%	2020
Washington, DC	RPS	20%	2020
West Virginia	AEPS	25%	2025
Wisconsin	RPS	10%	2015

*Colorado, North Carolina, Oregon and New Mexico has less stringent standards for certain municipalities, cooperative electric associations and/or smaller utilities.
**For Connecticut, an additional 4% is required from certain CHP and other energy efficiency measures.
***An additional 1% is expected from voluntary markets.

Indiana has not adopted a RPS, but legislation has been considered in previous sessions, and has been introduced in the current session.

In order to comply with these RPSs, a utility may invest funds in their own renewable energy facilities, purchase renewable energy from other providers, usually under long-term power purchase agreements (PPAs), or purchase renewable energy credits (RECs). Currently most utilities are meeting RPS requirements through the purchase of renewable energy under PPAs from independent power producers, developers and other electric providers. Regulated utilities, however, are now beginning to build their own renewable energy facilities. Trading of RECs is limited, making their value uncertain. The issue of who retains the RECs under the sale of electric power, however, has become an important part of PPA negotiations.

Legislation also is pending in Congress which establishes a RPS. On the House side, the American Clean Energy and Security Act of 2009 (ACES), H.R. 2454, 111th Cong. (209), (known as the Waxman-Markey Bill) was passed on June 26, 2009. The legislation provides for a Combined Efficiency and Renewable Electricity Standard (CERES) for electrical retail suppliers. The electric provider is required to provide a specific percentage of its electricity from renewable energy sources or energy efficiency savings. Renewable energy targets are established and increased over time. (Table 2) Biomass fuels, such as those being considered for JMEP, are included in the definition of renewable energy resource[7].

TABLE 2	
Calendar Year	**Required Annual Percentage**
2012	6.0
2013	6.0
2014	9.5
2015	9.5
2016	13.0
2017	13.0
2018	16.5
2019	16.5
2020	20.0
2021-2039	20.0

These targets may be met by using renewable energy sources or through energy efficiency. ACES permits up to 25% of the target to be met by energy efficiency. H.R. 2454 §610(b)(3). State Governors may petition the Federal Regulatory Energy Commission to have the 25% energy efficiency cap raised to 40%. H.R. 2454 §610(b)(4)(A). One federal renewable energy credit will be issued for each one megawatt hour of electricity generated from renewable sources. Electric providers will be required to establish compliance with the Federal RPS each year.

On the Senate side, the American Clean Energy Leadership Act (ACELA), S1462, 111th Cong. (2009) was passed out of the Senate Energy and Natural Resources Committee on June 17, 2009. The ACELA also establishes a Federal Renewable Electricity Standard for renewable energy and energy efficiency for regulated electric utilities. As with the ACES, specific percentages of a utilities' electricity must be provided from sources of renewable energy or energy efficiency. S. 1462 §610(b)(1)(A),(B) (Table 3).

TABLE 3	
Calendar Year	**Required Annual Percentage**
2012-2013	3.0
2014-2016	6.0
2017-2018	9.0
2019-2020	12.0
2021-2039	15.0

[7] Need footnote

Renewable sources under the Senate bill also include the biomass fuels. The ACELA provides that these federal standards may be met by renewable energy and energy efficiency credits to be filed with the U.S. Department of Energy. S. 1462 §610(c)(2) and 610 (i)(3), (4). In the alternative, compliance payments may be made by the electric provider. S. 1462 §610(b)(2)(A)-(D),

There are significant differences between the ACES and the ACELA, notably the ACELA does not include cap-in-trade regulation. Considerable debate in the Senate is anticipated with any version of the ACELA passed by the Senate being referred to a Conference Committee for reconciliation with the provisions of the House's ACES. The significance of this pending federal legislation is that the Federal RPS will in all likelihood increase the demand for renewable energy, as will the State RPSs, increasing the market price for renewable energy.

IV.
RENEWABLE ENERGY CREDITS

RECs are tradable certificates reflecting the environmental attributes of a renewable energy facility, or the fact that the facility is capable of generating electricity from renewable fuels. Generally one megawatt hour of electricity equals one REC. A utility may purchase RECs to meet State RPS requirements, rather than investing funds in a facility capable of producing renewable energy, or purchasing the renewable energy from other sources.

RECs will be carefully tracked by regional tracking systems. There have been five regional tracking systems already established:

- Midwest Renewable Energy Tracking System (M-RETS)[8]
- New England Power Pool – Generation Information System (NEPOOL-GIS)[9]
- Pennsylvania Jersey Maryland Independent System Operator – Generation Attribute Tracking System (PJM-GATS)[10]
- Western Renewable Energy Generation Information System (WREGIS)[11], and,
- Electric Reliability Council of Texas (ERCOT)[12]

The North American Renewables Registry also tracks renewable energy generation in states not covered by one of the regional systems.[13]

These tracking systems verify renewable energy generation at specific facilities for purposes of compliance with State RPSs. RECs are tracked over the life cycle of each certificate, recording trades, identifying the holder of certificates, and ensuring against double accounting.[14]

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[8] Need footnote
[9] Need footnote
[10] Need footnote
[11] Need footnote
[12] Need footnote
[13] Need footnote
[14] Need footnote

M-RETS serves the Midwest and includes the States of Illinois, Iowa, Minnesota, Montana, North Dakota, South Dakota, Wisconsin and the province of Manitoba. M-RETS works closely with the Midwest Independent System Operator (MISO) who operates the electric transmission grid for the Midwest.[15] Indiana does not presently participate in M-RETS, but is likely to become a member in the event that Indiana adopts an RPS.

In addition to the establishment of M-RETS, there are other important policy initiatives in the Midwest which are driving the development of new sources of renewable energy. These policy initiatives include the Midwest Greenhouse Gas Reduction Accord which was signed by Governors of six Midwestern states and the province of Manitoba in 2007; the Midwest Energy Infrastructure Accord which is part of the Midwest Governors Association's agenda; and, the Report of the Chicago Council on Global Affairs "Embracing the Future: the Midwest and a New National Energy Policy".[16] All of these initiatives and policy documents support the transition away from fossil fuels to renewable energy.

At this time it is difficult to place a value on RECs. It is clear that RECs will have a tangible monetized value reflecting the environmental attributes of renewable energy facilities, but at this point little trading has occurred which establish a market value in the Midwest. The right to RECs in the sale of electricity, however, has become an important issue in the negotiation of PPAs.

V.
CAP-IN-TRADE

The principal objective of all of these policy initiatives is to reduce CO_2 emissions. One of the approaches to reducing CO_2 is the much debated cap-in-trade. Under cap-in-trade, national target levels of the regulated emissions are set, and caps are imposed on individual sources which are designed to achieve the targeted levels. Each source is permitted for a specific number of allowances equal to its allowed emissions.

Allowances authorizing emissions are then allocated among sources, and limited in number to ensure the integrity of the national target levels. At the end of each year, every source must have enough allowances to cover its emissions for that year. Unused allowances, for those sources whose actual emissions are less than their caps, may be sold, traded, or saved (banked) for future use.

The concept is to allow for an economically efficient allocation of the costs associated with meeting CO_2 emission reductions. Each source has the opportunity to choose among alternatives that best meet its needs in complying with the emission caps. These alternatives include: installing pollution control equipment; switching to lower CO_2 emitting fossil fuels, such as natural gas; employing energy efficiency measures; using renewable fuels; buying excess allowances from other sources; or using a combination of these options.[17]

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[15] Need footnote

[16] Need footnote

[17] Need footnote

The cap-in-trade approach has been used by the Environmental Protection Agency in its Acid Rain Program which was adopted under Title IV of the 1990 Clean Air Act Amendments. SO_2 and NO_x emissions are subject to the caps. The number of allowances allocated to sources of these emissions are designed to meet the national targeted levels. The number of allowances decrease over time as the targeted levels for emissions decline. The Acid Rain Program has been quite successful with SO_2 emissions have decreasing by more than 30% from 1990 levels and NO_x emissions decreasing in the Northeast by 60% from 1990 levels. Costs of meeting targets also have been considerably lower than estimated.

The ACES, the recent energy legislation enacted by the U.S. House of Representatives, establishes an economy wide CO2 cap-in-trade program. The bill's cap-in-trade program, along with other incentives and standards for increased efficiency and low-carbon energy consumption, transforms the structure of energy production and consumption in the U.S. The share of primary energy provided by a low or zero-carbon sources of energy significantly increase. In terms of the cap-in-trade program in the bill, it is estimated that the price for allowances allocated to sources of GHG will trade at $13.00 per metric ton CO_2 equivalent in 2015 and $16.00 in 2020. The ACES also provides for domestic and international "carbon offsets," which are financial instruments designed to reduce GHG emissions and are also measured by CO_2 metric ton equivalents. A source of GHG emissions may invest in a domestic or international project resulting in GHG emissions reduction to offset its own emissions. This can be done for either mandatory compliance with CO_2 standards, or on a voluntary basis as a commitment to GHG emissions reduction.

The ACELA, pending in the U.S. Senate, does not include a cap-in-trade program. Considerable debate in the Senate is anticipated. As Congress debates cap-in-trade, however, administrative regulations are being promulgated to regulate GHGs. The U.S. Supreme Court has held that the U.S. Environmental Protection Agency (EPA) may regulate GHG emissions. *Massachusetts v. EPA,* 549 U. S. 497 (2007). As a result, the EPA issued a proposed rule on September 30, 2009 which requires permits for large facilities emitting over 25,000 tons of GHGs to demonstrate use of the best practices and technology to minimize these emissions. The rule proposes new thresholds for GHG emissions that define when the Clean Air Act permits under New Source Review and Title V operating permits would be required for more construction or modifications to existing facilities. Whether Congress or the EPA regulates GHG emissions is an important part of the cap-in-trade debate.

The significance of the anticipated cap-in-trade program is that it will result in higher costs for sources using fossil fuels, such as coal. The intended purpose is to transition from reliance on fossil fuels to greater use of renewable fuels. As the demand for renewable energy increases, so should the market price for electricity generated from sources using renewable fuels. This will have a favorable impact on future revenue streams from power sales from renewable energy facilities.[18]

[18] Need footnote

VI.
FEDERAL TAX INCENTIVES

Federal income tax incentives have played an important role in the development of renewable energy facilities. Generally these incentives are in the form of tax credits taken against the taxpayer's income tax liability. The purpose of the incentives is to attract investment capital from private capital markets. These tax credits have been particularly effective in developing the wind industry, and now are playing an important role in the development of the solar industry.

Production Tax Credit (PTC): A credit taken against the taxpayer's income tax liability based upon energy production. The EESA (October, 2008) and the ARRA (February, 2009) significantly expanded the eligibility and extended the required in-service dates for the PTC. Importantly, the ARRA allows the taxpayer who is eligible for the PTC to take the federal investment tax credit, or in the alternative, to receive a cash grant from the U.S. Treasury Department in lieu of the PTC.[19]

Investment Tax Credit (ITC): A credit against taxpayer income tax liability based upon the amount of the investment in the renewable energy facility. The amount of the credit can be 30% of the qualifying costs depending upon the type of renewable fuel and technology. In other instances 10% of the amount invested qualifies for the credit. The EESA (October, 2008) and the ARRA (February, 2009) significantly expanded the eligibility and extends the in-service dates for the ITC. The ARRA provides that a taxpayer eligible for the ITC may receive a cash grant from the U.S. Treasury Department instead of taking the ITC for new facilities. Certain open or closed loop biomass systems now qualify for a 30% tax credit through the in-service date of December 31, 2013.[20]

Treasury Grants: The ARRA created a renewable energy grant program that is administered by the U.S. Department of Treasury (Treasury). A taxpayer eligible for the ITC may take this credit or receive a grant from Treasury instead of the ITC. The new law also allows taxpayers eligible for the PTC to receive the grant instead of taking the credit. The cash grant is in the amount of 30% of the basis of the eligible property for the renewable energy facility. Grants are available to eligible property placed in service in 2009 or 2010, or placed in service by a specific credit termination date, which varies with the type of renewable fuel, if construction is started in 2009 or 2010. The grants are disbursed within 60 days of the date of the grant application, or the date the property is placed in service, whichever is later.[21]

Accelerated Depreciation: Under the Modified Accelerated Cost-Recovery System (MACRS) investments in certain property may be recovered through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. Certain renewable energy technologies are classified as five year property, with the qualifying property being defined under the ITC statute. Certain biomass property has a class life of seven years under MACRS. Eligible

[19] Need footnote
[20] Need footnote
[21] Need footnote

biomass property generally includes assets used in the conversion of biomass to heat and electric power. In the past, certain eligible renewable energy property which met specific requirements was entitled to deduct 50% of the adjusted basis of the property in 2008 and 2009, with the remaining 50% of the adjusted basis depreciated over the ordinary depreciation schedule.[22]

ARRA Grants: Congress through the ARRA appropriated $2.5 billion for renewable energy projects. Funds are being administered by the U.S. Department of Energy through their various energy programs. Most relevant to the JMEP are program funds being administered through the Office of Energy Efficiency and Renewable Energy. Grants are being made to local units of government through direct funding formulas (Block Grants) and through competitive grants. The grant application process is being administered through the federal grants program – FedConnect. Funding Opportunity Announcements (FOA) are routinely issued by FedConnect soliciting applications for renewable energy projects. Each FOA involves different projects or programs and has its own merit review criteria.[23]

Renewable Energy Production Incentive: Incentive payments for electricity generated and sold by a new qualifying renewable energy facility. Qualifying systems are eligible for payments of 1.5% per kilowatt hour in 1993 dollars (indexed for inflation) for the first 10-year period of operations, subject to the availability of annual appropriations. Eligible production facilities include government entities. Payments are made only for electricity generated from a qualifying facility first used prior to October 1, 2016. Appropriations have been authorized through fiscal year 2026. If there are insufficient appropriations to make full payments for electricity production from all qualifying facilities, the available funds are awarded on a pro rata basis.[24]

Rural Energy Program for America (REAP): A grant and loan guarantee program administered by the U.S. Department of Agriculture (USDA). The deadline for the last solicitation was July 31, 2009. Grants and loan guarantees are awarded for investments in renewable energy systems and feasibility studies. REAP promotes, among other things, renewable energy for agricultural producers and rural small businesses, with local governments being eligible to receive funding. Grants are limited to 25% of a proposed projects cost up to $25 million. At least 20% of the funds must be dedicated to grants of $20,000 or less. The USDA announces the availability of funding through Notice of Funds Availability.[25]

Clean Renewable Energy Bonds (CREBs): Bonds used primarily by the public sector to finance renewable energy projects. CREBs are issued, theoretically, with a 0% interest rate. The borrower pays back only the principal on the bond, and the bondholder receives federal tax credits in lieu of the traditional bond interest. CREBs differ from traditional tax-exempt bonds, in that the tax credits available to the bondholder are treated as taxable income. The EESA and the ARRA significantly increase the total allocation of CREBs to $2.4 billion. The expiration

[22] Need footnote
[23] Need footnote
[24] Need footnote
[25] Need footnote

date for new CREB allocations was August 4, 2009. It remains to be seen if the IRS will issue new funding announcements for CREBs.[26]

<u>Qualified Energy Conservation Bonds (QECBs)</u>: Bonds that may be used by local government to finance certain types of energy projects. QECBs are qualified tax credit bonds similar to CREBs. The EESA and ARRA expanded the allowable bond volume to $3.2 billion. Theoretically the interest rate on the bond is 0%, with the borrower paying only the principal on the bond, and the bondholder receiving federal tax credits in lieu of traditional bond interest. The definition of "Qualifying Energy Conservation Projects" is fairly broad, including projects involving renewable energy production. Renewable energy facilities that are eligible for CREBs are also eligible for QECBs.[27]

The significance of these tax incentives to the JMEP is access to the private capital markets, and lower cost public financing. These tax incentives have proven successful in the development of renewable energy facilities in certain sectors, most notably within the wind industry, and more recently in the solar industry. While the recent economic downturn and tightening credit markets have curtailed the usefulness of tax credits, there are recent indications of economic recovery and the loosening credit. The availability of these tax incentives may have a bearing on the Board's ability to access the private capital markets and to take advantage of a competitive market for project developers and investors.

VII.
RENEWABLE ENERGY MARKETS

On December 14, 2009 the Energy Information Agency (EIA) released its Annual Energy Outlook 2010 (AEO 2010) reference case. The EIA evaluates trends and issues impacting U.S. energy markets. The AEO 2010 reference case reflects current market conditions to the extent possible. The reference case assumes that current laws are unchanged and that sunset provisions in current laws will take effect ending current programs. The reference case does not consider legislation and regulations currently pending and which have a high probability of being enacted, nor does it consider that existing sunset provisions may be extended. The complete AEO 2010 report will include many additional cases which will assume the enactment of new policies and the extension of existing programs.

The AEO 2010 projects that electric consumption will increase at an average annual rate of 1.0% from 2008 to 2035. The fossil fuel share of energy consumption falls from 84% of the total U.S. energy demand in 2008 to 78% in 2035, reflecting the changes in U.S. energy policy. The mix of investments in new power plants includes fewer coal fired plants than other technologies. Coal, however, remains the dominant energy source for electric generation because of continued reliance on the many existing coal fired plants and the necessary construction of new plants to meet rising base load demands.

[26] Need footnote
[27] Need footnote

Natural gas will play a much larger role in the generation of electricity because of the growing concerns of GHG emissions. Gas fired plants are lower in GHG emissions and are much cheaper to build than coal or nuclear facilities. Natural gas supplies are expected to increase due to new extraction technologies and investments in oil production from shale fields.

Generation of electricity from renewable fuels increases significantly due to the changes in U.S. energy policies previously addressed, including state and potentially federal RPSs, federal tax incentives, ARRA funding, loan guarantee programs, low cost public financing, CO_2 regulation and anticipated cap-in-trade program. The AEO 2010 projects that the share of generation coming from renewable fuels will grow from 9% in 2008 to 17% in 2035. This is true even though the AEO 2010 reference case assumes federal subsidies expire as provided for by existing law. Any extension of these incentives could have substantial impact on renewable generation.

Unfortunately substantial uncertainty makes it difficult to forecast long term market prices for renewable energy. Among the many uncertainties are the extent to which U.S. energy policy will continue, or be reinforced by new legislative enactments. Renewable energy prices will no doubt be impacted by global initiatives to reduce GHG emissions, and U.S. commitments to these international goals. Regardless of energy conservation, demand for electric power will likely continue to increase. On the supply side, existing nuclear plant licenses are likely to be renewed along with new construction of nuclear facilities. The likely development and commercialization of new clean coal technologies and carbon capture and sequestration also may impact the growth in renewable energy supplies.

PRELIMINARY ANALYSIS
OF
MANUFACTURING WOOD WASTE

IN CONNECTION WITH

THE CITY OF JASPER
BIOMASS RENEWABLE ENERGY PROJECT

NOVEMBER 16, 2009

PERFORMED BY BINGHAM • MCHALE LLP

MANUFACTURING WOOD WASTE

As previously referenced, the Jasper / Dubois County area is one of the leading wood manufacturing clusters in the United States. We have performed an initial survey of several of the leading local businesses to determine the amount of wood waste produced by each as well as to determine the current use for such waste. While we have not yet had an opportunity to speak to every local manufacturer, the following is a summary of the information that we have obtained to date.

MasterBrand Cabinets, Inc.

I. Company Information.

MasterBrand Cabinets, A Fortune Brands subsidiary, is the second largest manufacturer of kitchen and bath cabinetry in North America. one of the world's largest cabinetry manufacturers (#2 in the US after Masco). Masterbrand's corporate headquarters are located several blocks from the Jasper Power Plant. MasterBrand Cabinets' brands include Aristokraft, Decorá, Diamond, Dynasty, Kemper, Omega, and Schrock, Aristokraft, Decorá, and Omega offer custom cabinetry and molding; Diamond, Kemper, and Schrock specialize in laminate, maple, and oak cabinetry. MasterBrand Cabinets also makes bathroom vanity products. MasterBrand Cabinets sells its products through home centers, lumber outlets, and specialty retailers.

II. Waste Produced.

MasterBrand's Dubois County Facilities produce about 1000 tons per month of sawdust waste and 500 tons per month of wood/plywood piece waste. In a strong or fair economy, MasterBrand produces significantly more wood waste.

III. Waste Disposal Process.

Masterbrand does not consider waste a commodity. MasterBrand has made the corporate decision that "they are in the cabinet business, not the sawdust business." MasterBrand has retained a third-party vendor to remove sawdust and waste. MasterBrand has indicated that they would be interested in exploring a potential relationship with the City of Jasper for removal of wood and sawdust waste.

Kimball International, Inc.

I. Company Information.

Kimball International's headquarters is located in Jasper, Indiana. Once a leader in the domestic piano business, Kimball International now has two primary business segments. Its furniture unit – which generates about half of its revenue – makes furniture and cabinets for the office, hospitality, and retail industries. Kimball's Electronic Manufacturing Services segment sells contract electronics and electro-mechanical assemblies primarily to the transportation and industrial markets. The company exited its forest products business in 2006.

Its customers for electronics services include companies in the transportation, industrial controls, and medical industries. Auto supplier TRW accounts for about 13% of the segment's sales, and some 7% of total net sales.

Kimball sold its forest products hardwood lumber business unit and a Pennsylvania-based fixed-wall furniture business unit in 2006. The same year Kimball sold its three lumber warehousing facilities, five log yards, three sawmills, and three lumberyards located in Indiana, Tennessee, Virginia, and Kentucky. The move allowed Kimball to exit its forest products business altogether and focus on the more profitable furniture, cabinets, and electronics units. The company sold its polyurethane and polyester molded components operations in 2006.

Kimball's corporate headquarters and many of its primary manufacturing facilities are literally located across the street from Jasper's Power Plant.

II. <u>Waste Produced.</u>

Kimball International produces a significant amount of sawdust/wood waste and wooden skids. Kimball provided the following information on its wood waste:

a. Kimball's 15th Street facility in Jasper produces 700 tons of sawdust and 4,000 lbs. of skids per year;
b. Kimball's Cherry Street facility in Jasper produces 2,000 tons of sawdust per year;
c. Kimball's 11th Avenue facility in Jasper produces 300 tons of sawdust and 10 tons of skids per year;
d. Kimball's 16th Street facility in Jasper produces 140 tons of sawdust and 1 ton of skids per year; and
e. Kimball's facility in Santa Claus, Indiana, produces 1,450 tons of sawdust and 125 tons of skid per year.

III. <u>Waste Disposal Process.</u>

Kimball reuses a significant amount of their waste in-house, but does sell some of its waste through outside vendors. All sawdust waste produced at the 15th Street, Cherry Street, 11th Avenue and 16th Street facilities are burned in Kimball's in-house boilers to produce heat and steam. The 15th Street, Cherry Street and 16th Street facilities are all located with 3 blocks of the Jasper Power Plant.

All waste produced in the Santa Claus, Indiana, facility is sold to third-party vendors.

Jasper Group/Jasper Seating Co., Inc.

I. Company Information.

Jasper Group's headquarters is located in Jasper, Indiana. Jasper Group manufactures wood office furniture, public building furniture, wood household furniture and nonwood office furniture. Their wooden office furniture line specializes in padded, plain or upholstered furniture (60%), their public building or related furniture line specializes in school furniture (20%, while their wooden household furniture (not upholstered) and the non-wooden office furniture comprises 10% each.

II. Waste Produced.

Jasper Group has no true measure of its waste production as Jasper Group burns the vast majority of its waste in its internal boiler system. However, based purely on projection by size of the company, we would estimate that Jasper Group produces slightly more waste than Indiana Furniture, or approximately 100 total tons of waste per month.

III. Waste Disposal Process

Most of Jasper Group's waste is used internally for boiler fuels. However in the summer. However, Jasper Group does produce excess waste in the summertime when they do not need to produce heat for their facilities. Jasper Group sells approximately 15-20 semi trailer loads of sawdust waste per summer to local farmers for animal bedding. Jasper Group charges $300-$400 per trailer load for sawdust waste.

Indiana Furniture Industries, Inc.

I. Company Information.

Indiana Furniture's headquarters is located in Jasper, Indiana. Indiana Furniture manufactures wood office furniture, public building furniture and upholstered household furniture. The wooden office furniture line specializes in desks, tables and padded, plain or upholstered furniture consisting of 70% of their business. Public building or related furniture production consists of 20%, specializing in school furniture. Indiana Furniture also manufactures wooden household furniture, specializing in chairs on wood frames, consisting of 10% of their business.

II. Waste Produced.

Indiana Furniture's facilities produce the following wood waste:

a. Indiana Furniture's plywood plant in Jasper produces 37 tons of sawdust per month;

b. Indiana Furniture's production facility in downtown Jasper produces 38 tons of waste per month; and

c. Indiana Furniture's production facility located in Dubois, Indiana, produces approximately 6 tons of flake core waste per month.

III. Waste Disposal Process.

Indiana Furniture does not use its wood waste and pays to have it removed. Indiana Furniture pays an outside vendor $44 per ton to remove waste.

Jasper Desk Company, Inc.

I. Company Information.

Jasper Desk's headquarters is located in Jasper, Indiana. Jasper Desk manufactures wooden office furniture, specializing solely in desks and tables selling to office furniture dealers in the United States. Jasper Desk began production in 1876.

II. Waste Produced.

Jasper Desk has not computed the amount of waste produced, as it burns its wood waste internally in its boilers. In general, Jasper Desk is a slightly smaller company than Indiana Furniture and likely produces somewhat less wood waste.

III. Waste Disposal Process

Jasper Desk burns all of its wood waste in its internal boiler system to produce heat for kilns, finish room and other production areas. Jasper Desk also purchases wood waste from two other local companies for this same purpose.

JOFCO, Inc.

I. Company Information.

JOFCO's headquarters is located in Jasper, Indiana. JOFCO manufactures wholesale furniture, office or public building furniture and household furniture consisting of 50% of production, wooden office furniture, specializing in padded, plain or upholstered furniture, desk, cabinets and free-standing panel systems or partitions consisting of the other 50%. JOFCO has 1,000 accounts, selling to office equipment dealers and distributors in the United States and Canada. JOFCO began in 1992 by the Sturm family with 100% of the capital stock being owned by 290 stockholders.

II. Waste Produced.

JOFCO has not computed the amount of waste produced, as it burns its wood waste internally in its boilers. In general, JOFCO is a slightly smaller company than Indiana Furniture and likely produces somewhat less wood waste.

III. Waste Disposal Process.

JOFCO burns all of their waste in their boiler, supplementing with coal. The previous year was the first year JOFCO did not have enough waste for this purpose.

Jasper Chair Company

I. Company Information.

Jasper Chair's headquarters is located in Jasper, Indiana. Jasper Chair manufactures wood office furniture, public building furniture, nonwood office furniture, upholstered household furniture and wood household furniture. Jasper Chair's wood office furniture specializes in padded, plain or upholstered furniture while the public building or related furniture line specializes in school furniture.

II. Waste Produced.

Jasper Chair has not computed the amount of waste produced, as it burns its wood waste internally in its boilers. Compared to the other company's listed, Jasper Chair likely produces a smaller amount of waste.

III. Waste Disposal Process.

Jasper Chair burns all of its wood waste in its internal boiler system to produce heat for kilns, finish room and other production areas.

Inwood Office Furniture, Inc.

I. Company Information.

Inwood Office Furniture is headquartered in Jasper, Indiana. Inwood Office Furniture manufactures wood office furniture, consisting of 80% of production, while production of school furniture consists of 20%.

II. Waste Produced and Disposal Process.

We have not received waste production or disposal information from Inwood at this time.

Best Chairs, Inc.

I. Company Information.

Best Chairs, Inc. is headquartered in Ferdinand, Indiana. Best Chairs, Inc. manufactures upholstered wooded chairs and retail furniture.

II. Waste Produced.

Best Chairs, Inc. produces approximately 11-12 semi-loads per month of wood/plywood shavings. We have not received waste production or disposal information from Inwood at this time.

III. Waste Disposal Process.

Best Chairs, Inc. sells their waste disposal to Amish turkey farmers for $200 per semi-load to use as bedding. The plywood shavings could contain glue and Best Chairs has no way to segregate the plywood shavings from the clean shavings.

OFS Brands, Inc.

I. Company Information.

OFS Brands, Inc. makes, sells and leases office furniture. It sells premade case goods (desks, bookcases, filing cabinets), seating and conference room furniture under the name OFS, Carolina, Styline, and First Office. OFS also makes custom office furniture and display cases. The furniture is produced in about a dozen plants and is hauled by its transportation and logistic subsidiary, which transports furniture for OFS, as well as other manufacturers. OFS was founded as a wood furniture manufacturer in 1937 and remains family-owned.

II. Waste Produced.

We have not received waste production information.

III. Waste Disposal Process.

OFS burns their own waste in the winter to heat their facilities.

Dubois Wood Products, Inc.

I. Company Information.

Dubois Wood Products manufactures wood furniture.

II. Waste Produced.

Dubois Wood produces approximately 2 semi-loads of solid wood pieces / particle board pieces and 2 semi-loads and three 20-foot trailers per week of sawdust in the summer months.

III. Waste Disposal Process.

Dubois Woods gives most of their waste to Jasper Desk. Some is given to a couple of farmers in during the summer and during the winter for use in their boilers for heat. Dubois Wood hauls it for free. Also, Koetter & Sons takes the waste and sells it to farmers.

CITY OF JASPER - BIOMASS PROJECT
Manufacturing Wood Waste Analysis

MANUFACTURER	LOCATION	SIZE	CONTACT PERSON	WASTE PRODUCED	WASTE DISPOSAL PROCESS
MASTERBRAND CABINETS	Multiple Locations in Dubois County		Greg Stoner / Rob Mullaly Mike Decker (now primary contact): office 367-3348 Cell: 639-2946	Dubois County Facilities produce about 1000 tons per month of sawdust and 500 tons per month of wood/plywood piece waste. This is very low for them due to economy. In a strong economy they produce far more. Leon Halter of ESG previously contacted Masterbrand in June.	Masterbrand does not consider waste a commodity. Mike stated that they have made the corporate decision that 'they are in the cabinet business, not the sawdust business." They hire an outside source to remove sawdust and waste. They would be very interested in working with Jasper. They invited us to come and look at their facilities to analyze possibilities. Masterbrand's primary concern is timeliness of waste removal. Mike stated "if our bins fill up and waste is not removed on time, we have to shut the whole plant down."
KIMBALL INTERNATIONAL			Julie Heitz / Ron Rothgerber/ Keith Masterson Phone: 634-3291	Sawdust/wood waste and Wooden skids	100% is either re-used in-house or goes through vendors
	15th Street, Jasper			700 tons of sawdust per year 4,000 lbs. of skids per year	All used internally for boiler fuels (also purchase 500 tons for use) Went to recycler
	Cherry Street, Jasper			2,000 tons of sawdust per year	All used internally for boiler fuels
	11th Avenue, Jasper			300 tons of sawdust per year 10 tons of skids per year	All used internally for boiler fuels Returned to venders for re-use
	16th Street, Jasper			140 tons of sawdust per year 1 ton of skids per year	All used internally for boiler fuels Goes to recycling
	Santa Claus			1,450 tons of sawdust per year 125 tons of skids per year	Goes to outside vendors for use
JASPER GROUP	Jasper		Chris Berg		Much used internally for boiler fuels, everything else sold to a farmer for bedding In summer have extra, and may ship out 15-20 semi trailer loads to farmer, paying @ 300-400 per trailer load

CITY OF JASPER - BIOMASS PROJECT
Manufacturing Wood Waste Analysis

MANUFACTURER	LOCATION	SIZE	CONTACT PERSON	WASTE PRODUCED	WASTE DISPOSAL PROCESS
INDIANA FURNITURE			Bret Ackerman / Larry Urich		
	Plywood Plant			General waste – 37 tons per month	Regular waste going to Koetter & Smith – IFI pays $44 per ton to have removed
	Downtown Plant			General waste – 38 tons per month	Regular waste going to Koetter & Smith – IFI pays $44 per ton to have removed
	Dubois Plant			General waste – 6 tons per month – flake core	Regular waste going to Koetter & Smith – IFI pays $44 per ton to have removed
JASPER DESK			Phil Gramelspacher	They don't know how much they produce	They burn it all in their own boilers to produce heat, kilns, finish room heat, etc. They also purchase waste from 2 other companies for this purpose
JOFCO	Jasper		Adam Smith / Vernon Seng (481-7262) Safety & Environmental Mgr.	Wood	Burn all in their boiler and they supplement with coal. Last year first year they did not have enough wood
JASPER CHAIR	Huntingburg		Chad Barth	Wood Semi-load of skids	Burn in boiler and generate steam with it Don't use skids, this may be available
OFS	Huntingburg		Jim Huebner / Jeff Eckert		Burns their own in winter to heat facility
DUBOIS WOOD	Huntingburg		Phil Lueken	Solid wood pieces / particle board pieces – 2 semi-loads Sawdust – 3 20-foot trailers per week during summer	Giving all to Jasper Desk Give to a couple of farmers in summer / during winter burn it in their own boiler for heat Commonplace to haul for free Koetter & Smith takes and sells to farmers
BEST CHAIRS	Ferdinand		Pat Miller / Stewart Curtis 367-0113	Wood/plywood shavings – 11-12 semi-loads per month	Sells to Amish turkey farmers for $200 per semi-load to use as bedding / Plywood shavings could contain glue – they have no way to segregate plywood shavings from clean shavings
MOBEL	Ferdinand		Ruhe		No contact made.
INDUSTRIAL WOODKRAFT	Boonville		Thad Leinenbach		No contact made.

Bingham • McHale LLP
ATTORNEYS AT LAW

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December 10, 2009

VIA ELECTRONIC MAIL
vizcarraje@bv.com

Mr. Jorge E. Vizcarra
Project Manager
Black & Veatch Corporation
11401 Lamar Avenue
Overland Park, KS 66211

RE: Additional Biomass Supply

Dear Jorge:

I am forwarding to you two spreadsheets which identify the availability of additional biomass supply from local sawmills and urban tree trimming operations. There are separate Excel spreadsheets for each sawmill and urban tree trimming operation. This is additional information which would support our prior analysis for the case scenarios to be used by Black & Veatch confirming that an adequate biomass supply of greenwood is potentially available. These sawmills and urban tree trimming operations are within a 50-60 mile radius of the City of Jasper Municipal Power Plant. As you peruse the spreadsheets, you will notice that these operations vary in size and sophistication. We also were able to obtain general information about how the biomass currently is being utilized, the prices at which it is being sold, and to whom it is being sold. The urban tree trimming operations generally produce woodchips and greenwood. The sawmills operations generally produce woodchips, greenwood, cull logs and sawdust. We also undertook some investigation of logging operations within a 50-60 mile radius of the City of Jasper Municipal Power Plant, which did not prove to be very helpful in identifying potential biomass supply.

In sum, it appears that there is approximately 900 to 1,000 tons per week available from urban tree trimming operations, and approximately 1,200 to 1,300 tons per week available from local sawmill operations.

Please feel free to contact Eric or me with any questions you may have regarding the information contained in these spreadsheets as to the availability of additional biomass supply.

Very truly yours,

BINGHAM • MCHALE LLP

William J. Kaiser, Jr.

Attachments

90266v1

cc: Mr. Gerald Hauersperger (w/attachments) (via email)
Mr. James C. Reichenbach (w/attachments) (via email)
Sandra K. Hemmerlein, Esq. (w/attachments) (via email)
Mr. Peter H. Grills (w/attachments) (via email)

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/truckloads per week]*	Green Wood *[tons per week/truckloads per week]*	Current Disposal or Sale	Notes
Action Affordable Tree Service 7752 S. Pleasant Main St. Carlisle, IN (812) 659-2090				Disconnected number
Affordable Tree Service Rockport, IN 47635 (812) 457-8896				Out of business
Allan's Tree Service Boonville, IN (812) 475-9620				Left message
All Season's Affordable Tree Service Pleasantville, IN (812) 659-4221				No answer
American Eagle Tree Service LLC 8900 North Line Road Dale, IN (812) 937-4578				Left message
American Tree Experts Shoals, IN 47581 Marie (812) 247-3003	1.5 tons/6 truckloads	5 tons/ Do not truck bring back to office	Wood Chips - dispose at local dump/pay to dump the waste. Green Wood - customers keep, give to a friend, or sell for $45-$50/face cord.	They do not believe in topping off trees
Broomie's Tree Service 5834 S. Rome Rd. Rome, IN (812) 836-2753				Disconnected number
Bruce's Tree Trimming 9698 E. County Road 1200 S. Stendal, IN 47585 Bruce Miller (812) 536-3688	None	Minimal		Very small business-phasing out
Chancey and Sons Tree Service 3603 Vincennes Trail Salem, IN Daniel Chancey (812) 883-6887	20 tons/10 truckloads	40 tons/40 rigs	Wood Chips - dispose at natural landfill. Green Wood - dispose at natural landfill or take home to sell for $35/rick.	Right now don't pay to dispose at landfill

Name/Address/Contact/Phone No.	Wood Chips [tons per week/truckloads per week]	Green Wood [tons per week/truckloads per week]	Current Disposal or Sale	Notes
Crooked Creek Logging, LLC 9378 E. County Road 1850 N. Ferdinand, IN 47532 Matt Feldpausch (812) 630-1045	None	60,000-70,000 board feet/or 480-560 tons/week- 12-15 truckloads	Sells to sawmills- $28.00/ton for pulp and .30-.40/board feet	Is a logging company not a tree trimmer. Figure for green wood includes the cull logs.
D & D Tree Service 4505 Wilson Dr. NE Palmyra, IN 47164 (812) 225-6349				Left message
Dewitt Tree Surgery 3211 N. Cedar Gap Ln. Birdseye, IN 47513 (812) 634-1071				No answer
Foster Tree Service 809 W. 300 S. Washington, IN Pat Foster (812) 257-1000	None	40-50 tons/5 semi loads	Give it away for firewood to friends	VERY INTERESTED
Hunter Outdoor Services Inc. Bob & Cyndi Graham (812) 362-7037				Left message
Jones Tree Service 8982 Hopkins Ln. Shoals, IN Kenneth Jones (812) 247-3423	15 tons/5 truckloads	15 tons/5 truckloads	Give it away for firewood to friends	Will there be help with transportation?
Melton's Tree Service 204 Indiana Ave. Loogootee, IN Bob Melton (812) 295-4748	50-55 tons/15-30 truckloads	Over 100 tons/ over 30 truckloads	Give it away for firewood to friends	
One Way Tree & Land Services Inc. 5933 Hunter Rd. Boonville, IN (812) 499-5090	N/A	N/A		Business is mowing down small trees and bush does not pick it up.

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/truckloads per week]*	Green Wood *[tons per week/truckloads per week]*	Current Disposal or Sale	Notes
Radcliff Tree Service 9033 West State Rd. 64 Birdseye, IN Dave Wadsworth (800) 230-7711				**No answer**
Team Tree Inc. 1709 N. State Road 545 Celestine, IN Steve Kluesner (812) 678-2196	**25-30 tons/10 truckloads**	**50 tons/10 truckloads**	**25%- taken to landfill 50% recycling as compost 25% sold as firewood for $40/truck**	
Top Notch Tree Service (812) 549-9412				**No service**
W O Tree & Stump Removal 4304 Aj Ave. NE Palmyra, IN 47164 Harold Gilley (812) 734-4580	**30 tons/10-12 truckloads**	**20 tons/5-6 truckloads**	**Charged to dump at Herb First in Greenville, IN**	
Summary - tons per week by category	**142-152 tons**	**750-840 tons**		
Total Summary - total tons per week	**892-992 tons**			

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/truckloads per week]*	Green Wood *[tons per week/truckloads per week]*	Current Disposal or Sale	Notes
Following companies - Greater potential for Biomass supply: **Crooked Creek Logging** **Meltons Tree Service** **Team Tree, Inc.**				
Above information obtained in November, 2009, from teleconferences with business owners, and is based on approximations provided by business owners.				
No documents or written reports were received or reviewed.				

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/ truckloads per week]*	Green Wood *[tons per week/ truckloads per week]*	Cull Logs *[tons per week/ truckloads per week]*	Sawdust *[tons per week/ truckloads per week]*	Current Disposal or Sale	Notes
C & L Lumber 8836 W. SR 64 Huntingburg, IN Larry Jones (812) 536-2171	None	50 tons/don't truck	None	2-3 tons/don't truck	Green Wood - sold to 3rd parties for $10.00 a pick-up load Sawdust - give away stacked on site	Not producing much now due to the economy
Casper Enterprises Sawmill & Logging 11446 Odyssey Rd. Saint Croix, IN Charles "Chuck" Casper (812) 843-5251 (812) 549-6051 cell						Left message
Combs Bros. Lumber Co. RR 3 Bloomfield, IN (812) 863-2300						Disconnected number
D & G Timber Swartzentruber Saw Mill 5878 N. 900 E. Montgomery, IN Mike Swartzentruber (812) 486-3356	None	5-10 tons/don't truck	Minimal	40 tons/two 20 ton trucks	Green Wood - sold to 3rd parties for $25 per scoop/pick-up load Sawdust - sold to local farmers for livestock for $25.00/ton	
Day's Logging 878 Bramble Rd. Loogootee, IN (812) 295-5087						Disconnected number
Hoffman Sawmill 3277 W. 700 N. Jasper, IN 47546 Leroy Hoffman (812) 695-2200	None	8-12 tons/1 trailer holds 8-12 bundles	20,000-30,000 feet/or 160-240 tons don't truck	40 tons/two 20 ton trucks	Green Wood - sold to Virgil Werner for $7-$10/bundle Cull Logs - sold to pallet companies for .30 to .50 a foot Sawdust - sold to local farmers for livestock for $10 a truck load or $25 a trailer load, etc.	Bundle of Green Wood weights 1 ton

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/ truckloads per week]*	Green Wood *[tons per week/ truckloads per week]*	Cull Logs *[tons per week/ truckloads per week]*	Sawdust *[tons per week/ truckloads per week]*	Current Disposal or Sale	Notes
Paul Knepp Saw Mill 3501 N. 900 E. Montgomery, IN Dale Knepp (812) 486-3773	Minimal	5 ton/don't truck	None	1 ton/don't truck	Green Wood - give it away Sawdust - give it away	Likes this idea of a Biomass facility. Noted there is one in Hawesville KY and they require the wood waste to be debarked.
Eli Knepp Saw Mill 5840 N. 975 E. Loogootee, IN Phil Knepp (812) 486-2913	None	2 semi-load/ don't truck	Same as Green Wood	3/4th semi-load/ don' truck	Green Wood use for fuel at the company Sawdust - give it away	
Charles W. Knies Sawmill Inc. 2238 E. 550 S. Huntingburg, IN Carla Knies (812) 683-3402						Due to economy not producing much what they do produce they are using for heat
Lasher Lumber Inc. 15147 State Road 145 Tell City, IN Barbara Lasher (812) 836-2618						Closed for business
Leibering Lumber & Logging Inc. 543 W. 8th Street P.O. Box 189 Ferdinand IN Shawn Leibering 812-367-1646	50-70 tons/ 2-3 truck loads	See notes	See notes	50 tons/ 2-3 truckloads	All product ground into wood chips. Wood Chips - $25-30/ton Sawdust - $10/ton	Also has a Dimension Plant - producing 20-25 tons/week 1 truckload/ week. Also has logging production over 500 tons/week VERY INTERESTED
Newton Planing Mill 3539 W. Mcwilliams School Rd. Taswell, IN (812) 338-3221						No Answer
Pendley Wood Products 2848 S. County Road 1050 W. French Lick, IN (812) 936-3377						No Answer
Pride Hardwoods (812) 936-4100						Disconnected number

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/ truckloads per week]*	Green Wood *[tons per week/ truckloads per week]*	Cull Logs *[tons per week/ truckloads per week]*	Sawdust *[tons per week/ truckloads per week]*	Current Disposal or Sale	Notes
Randall Lowe & Sons Sawmill 6543 W. County Road 875 S. French Lick, IN Sarah Lowe (812) 936-2254	None	1 ton/ truck when trailer full	None	155 tons/ 4 truckloads	Green Wood - sent out to be chipped by Greendale Mulch Company/Paid $550.00/truckload Sawdust - sent to Domtar Plant in Hawesville KY for pulp and fine paper/Paid $2,697.00/month-Flat rate	
Ronald Wright Logging LLC 61 S. Pleasant Hill Rd. English, IN Ronnie Wright (812) 338-2665						Don't produce any wood waste
Southern Indiana Hardwoods 2553 S. St. Anthony Road W. Huntingburg, IN Gene Merkley (812) 326-2053	250 tons/ 10 truckloads	None	None	125 ton/ 5 truckloads	Sawdust and wood chips coverted to wood pallets and sold for $175/ton	
Swartzentruber Sawmill 5912 N. 900 E. Montgomery, IN Randy Swartzentruber (812) 486-3350	100 tons/ 5 truckloads	Would not disclose	Would not disclose	Would not disclose		He stopped providing any information because he is angry that the EPA shut them down a few years ago for burning on site. He did say they are grinding all the wood waste into mulch.
Tri-State Veneer Sawmill French Lick, IN (812) 936-2955						No Answer
Werner Sawmill Inc. 3545 N. 550 W. Jasper, IN 47546 Luke Werner (812) 634-9444 Business (812) 482-7565 Home						Left message

Name/Address/Contact/Phone No.	Wood Chips [tons per week/ truckloads per week]	Green Wood [tons per week/ truckloads per week]	Cull Logs [tons per week/ truckloads per week]	Sawdust [tons per week/ truckloads per week]	Current Disposal or Sale	Notes
Westwood Lumber Inc. 3155 W. State Road 64 Taswell, IN Jeff Roll (812) 338-2465	80 ton/ 2.5 truckloads - Clean	None	None	80 ton/ 2.5 truckloads	Wood chip and sawdust sold $11/per ton FOB -his site	Working Koetter & Smith, Borden IN shaving project - suppliers of biomass Very interested in being sole supplier of biomass for the City of Jasper 253 trucks nationwide Wants us to contact Koetter & Smith at 812-923-5111 Nathan Smith and Jay Ingle
Summary - tons per week by category	**480-500 tons**	**70-80 tons**	**160-240 tons**	**494 tons**		
Total Summary - total tons per week	**1204-1314 tons**					
Following companies - Greater potential for Biomass supply: **Hoffman Sawmill** **Leibering Lumber & Logging** **Southern Indiana Hardwoods** **Westwood Lumber, Inc.**						
Above information obtained in November, 2009, from teleconferences with business owners, and is based on approximations provided by business owners.						
No documents or written reports were received or reviewed.						

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/ truckloads per week]*	Green Wood *[tons per week/ truckloads per week]*	Cull Logs *[tons per week/ truckloads per week]*	Sawdust *[tons per week/ truckloads per week]*	Current Disposal or Sale	Notes
Andis Logging Inc. 76 W. County Road 550 S. Paoli, IN 47454 Robert Andis (812) 723-2357	Miminal	Miminal	Miminal	Miminal		Miminal wood waste - Little produce and uses for heating their building. Appreciates that the City of Jasper is interested in biomass. Worried about the cost for trucking to the plant.
C & S Logging 1994 S. County Road 300 E. Paoli, IN 47454 Eddie Crane (812) 723-3923						No logging at this time, but very interested in biomass project.
Cash Logging 20198 N. State Road 66 Cannelton, IN 47520 James Cash (812) 843-5335	None	25,000 feet/ 6 semi loads	1,000 feet/ truck when full load	None	Getting .54/foot for grade logs	Against biomass used for fuel. Worried about the raping of the trees. Worried about the loss of young trees. Worried about the buying of pulp wood to meet the needs for biomass facility.
Casper Enterprises Sawmill & Logging 11446 Odyssey Saint Croix, IN (812) 843-5251						Left message
Michael Deom Professional Logging 13208 Deer Creek Rd. (812) 836-2206						Left message
Dickey Logging 4329 S. County Road 250 E. Paoli, IN 47454 (812) 723-0075						Disconnected number
Richard Greg Etienne Logging 11133 Trumpet Rd. Derby, IN 47525 (812) 843-5208						Left message
Mike Fischer Logging 6480 E. 850 S. Ferdinand, IN (812) 357-2169						Call back on December 4, 2009

Name/Address/Contact/Phone No.	Wood Chips [tons per week/ truckloads per week]	Green Wood [tons per week/ truckloads per week]	Cull Logs [tons per week/ truckloads per week]	Sawdust [tons per week/ truckloads per week]	Current Disposal or Sale	Notes
Jerry's Custom Crafts 11185 E. State Rd. 62 St. Meinrad, IN (812) 357-2894						
Knepp Logging 2946 N. 900 E. Loogootee, IN 47553 David Knepp (812) 486-3741 812-486-7721 cell	Owners keep the wood chips	2.3 million feet/year 621 truck loads/ year	Included with Green Wood figure	None	Average .23 to $5.00/ft Based upon the grade	
Delmar Knepp Logging 10293 E. 600 N. Loogootee, IN 47553 Delmar Knepp (812) 486-2565	None	Miminal	10 ton/ 1/2 semi-traller	5 tons/ don't truck	Cull Logs - $30/ton for firewood Sawdust - give away	Produce furniture logs and veneer
Jr. Knox & Sons Logging 8256 S. State Rd. 257 Stendal, IN (812) 536-3519						Disconnected number
Lasher Lumber Inc. 15147 State Rd. 145 Tell City, IN Barbara Lasher (812) 836-2618						Closed for business
Leibering Lumber & Logging Inc. 543 W. 8th St. P.O. Box 189 Ferdinand, IN Shawn Leibering (812) 367-1646	Over 500 tons/ 25 truckloads	See notes	See notes	See notes	Wood Chips - $25-30/ton	All product grounded into wood chips. Also see Sawmill production
Moffatt Brothers Logging & Lumber Shoals, IN (812) 247-4060						No answer

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/ truckloads per week]*	Green Wood *[tons per week/ truckloads per week]*	Cull Logs *[tons per week/ truckloads per week]*	Sawdust *[tons per week/ truckloads per week]*	Current Disposal or Sale	Notes
Nalley Logging 4825 S. County Road 300 E. Winslow, IN 47598 (812) 789-5315						
Larry Pendley Logging 11974 W. US Highway 150 West Baden Springs, IN 47469 (812) 936-2022						Disconnected number
Picou Logging 18938 N. State Road 66 Cannelton, IN 47520 Charles Picou (812) 843-5334	None	None	8 ton every 2 weeks/ one truckload	None	$160.00 for 8 ton for either cull logs or pulp	Produce pulp and cull logs Cull Logs - Sell to sawmills Pulp - Selling to neighbors for the heat
Albert Ransom Logging & Sawmill Inc. 7300 Lauderdale Rd. Dale, IN (812) 567-2012						
Lowell Ransom Logging 12129 N. County Road 250 E. Chrisney, IN 47611 (812) 362-8885						
Rasche Bro Logging 12242 E. Monte Casino Rd. Ferdinand, IN 47532 (812) 357-7782						
Jim Rhodes Logging 2121 W. State Road 62 English, IN 47118 (812) 739-4221						
Allen Schnell 2391 N. 900 E. Dubois, IN 47527 (812) 678-3680						

Name/Address/Contact/Phone No.	Wood Chips *[tons per week/ truckloads per week]*	Green Wood *[tons per week/ truckloads per week]*	Cull Logs *[tons per week/ truckloads per week]*	Sawdust *[tons per week/ truckloads per week]*	Current Disposal or Sale	Notes
Walton Logging 991 S. State Road 66 Marengo, IN 47140 (812) 365-9635						
Ronald Wright Logging LLC 61 S. Pleasant Hill Rd. English, IN 47118 (812) 338-2665						

Bingham ● McHale LLP

a t t o r n e y s a t l a w

BIOMASS CASE ANALYSIS SCENARIOS

CO-FIRE – 20%

Scenario 1 Industrial Wood Waste Only

Scenario 2 Green Wood Only

Scenario 3 Combination of Industrial Wood Waste and Green Wood

100% BIOMASS

Scenario 4 Combination of Industrial Wood Waste and Green Wood

Scenario 5 Combination of Industrial Wood Waste, Green Wood and Corn Stover

Scenario 6 100% Corn Stover

100% COAL

Scenario 7 Use of Coal Only (Base Case)

ASSUMPTIONS

- Assumed Delivered Cost of Green Wood at $37 Per Ton.
- Assumed Delivered Cost of Industrial Wood Waste at $20 Per Ton.
- Assumed Delivered Cost of Corn Stover at $45 Per Ton.

Reichenbach, James C. (Jim)

From: Sharon Wagner [SWagner@binghammchale.com]
Sent: Thursday, December 10, 2009 3:05 PM
To: Reichenbach, James C. (Jim)
Subject: Biomass Case Analysis
Attachments: #90274 - Biomass Case Analysis Scenarios - Condensed - v1.pdf

Mr. Reichenbach,

Bill Kaiser requested I forward to you the attached for discussion tomorrow during the 10:00 a.m. teleconference.

Sharon

Bingham McHale LLP
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