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Source of document:	FOIA/Privacy Act Officer National Energy Technology Laboratory 626 Cochrans Mill Road P.O. Box 10940 Pittsburgh, PA 15236-0940

October 14, 2011

Re: Freedom of Information Act Request
HQ-2011-02016-F

This is in response to your Freedom of Information Act (FOIA) request sent to this office for response by the Office of Information Resources. You asked for a copy of the Statement of Work and the presentation slides regarding Contract No. DE-AD26-07NT43287 entitled Economic Analysis of the Potential for Energy Gains in the US Industrial Sector. Additional time was needed in processing your request because the records were retired and archived.

Enclosed is a copy of the Statement of Work and the slides that you requested that are the responsive records from the National Energy Technology Laboratory (NETL).

This is the final response to your request. If you have any questions, please feel free to contact NETL's Freedom of Information Act Officer, Ann Dunlap, at (412) 386-6167.

Sincerely,

Scott Klara for AVC
Anthony V. Cugini
Director
Authorizing/Denying Official

Enclosures

Statement of Work

Economic Analysis of the Potential for Energy Gains in the US Industrial Sector

DE-AD26-07NT43287

A. SCOPE OF WORK

The Industrial Technology Program (ITP) of the Energy Efficiency and Renewable Energy (EERE) program office at the Department of Energy (DOE) is interested in developing new economic analyses of the potential for energy efficiency gains in the US industrial sector and in releasing a clear and compelling report describing these findings. In order to achieve this better understanding, the United States Government will contract with an organization (hereinafter, "the Contractor") to validate the industrial sector energy efficiency opportunity in the US, identify specific Government actions related to this opportunity and develop a communication package summarizing these findings, analysis, and recommendations.

Three core steps to a successful effort include:

1. Validate the overall size and importance of the industrial sector energy efficiency opportunity in the US, and prioritize specific energy efficiency improvement opportunities.

2. Identify the specific government actions with the greatest potential either for near-term impact and/or overall longer-term gains in energy productivity.

3. Develop for key stakeholders a clear and compelling communications package summarizing these findings, analyses, and recommendations.

B. TASKS TO BE PERFORMED

Task 1. Validate the industrial sector opportunity.

The Contractor shall develop a national model of industrial sector energy consumption incorporating top-down structural elements, including but not limited to:

Impact of macroeconomic factors:

Historical and projected output growth rates of constituent industrial sub-sectors; and

Projected factor costs including but not limited to energy inputs.

As an integrated and complementary element of the modeling approach, the Contractor shall include detailed modeling of individual industrial sub-sector dynamics, including but not limited to:

Price sensitivity to input costs;

Types of energy consumption by sub-sector (e.g., steel, petrochemical, pulp and paper, other manufacturing); and

Competitive and financial incentives of individual companies in each sub-sector; sub-sector micro-economics including express consideration of second-order impacts of changes in energy consumption, such as changes to industry cost curves or impacts on production capacity investments.

The modeling shall focus on understanding the relationship between sub-sector output levels, required energy consumption levels, and the efficiency characteristics of each consumption level. The modeling focus shall also incorporate scenarios for the productivity gains of specific technology adoption/replacement, as applied to the specific energy consumption characteristics of different industrial sub-sectors. Examples include, but are not limited to:

Applying best practices to local power generation and process heat systems;

Changing production processes to include less energy-intensive materials;

Switching to more efficient fuels; and

Upgrading core energy processes to newer, more efficient technologies.

The Contractor shall develop a number of likely scenarios for US industrial sector energy consumption. Collectively, these scenarios shall describe the absolute size of the energy efficiency improvement opportunity from the industrial sector; the range and timing of outcomes under different scenarios for pace and aggressiveness of change; and a preliminary list of likely priority sub-sectors and opportunity areas.

Task 2. Identify high-potential government actions.

The Contractor shall prioritize the kinds of government actions that will have the most impact on improving industrial sector energy productivity. Focus on providing fact-based analysis of specific areas where public sector intervention would add the most improvement and on the kinds of actions most likely to bring desired gains. The contractor shall utilize past and current ITP initiatives as a basis for input into the initial set of potential actions to be assessed. The Contractor shall survey other global economies for recent examples of effective government actions.

The goal of the prioritization process should be to highlight actions with the greatest impact on energy efficiency relative to second-order impacts, i.e., those actions that best advance energy productivity. The contractor will then recommend isolating and prioritizing for implementation those actions with the largest absolute impact and/or the most rapid material impact on overall energy consumption.

Task 3. Develop communications materials.

The Contractor shall deliver a set of communications materials summarizing the findings from the first two tasks above.

The Contractor shall deliver a full report of the findings, analyses, and recommendations. This report shall be professionally produced and edited, and upon completion, ready for use by ITP in stakeholder discussions and other communications. The final report shall range from 50-100 pages or more, and include the following sections:

Analysis and findings of the potential for energy efficiency gains in the US industrial sector overall, including comparisons to opportunities in adjacent areas such as residential and consumer;

Analysis, discussion, and findings of the specific opportunities as well as key challenges in the most significant sub-sectors of the US industrial sector, numbering no more than 3-4 such sectors;

Discussion and description of the kinds of government policies that could best enhance industrial sector energy efficiency gains, including assessments of market failures or other barriers to private sector action in a particular area, as well as comparative examples from other markets as applicable;

Supporting charts, tables, and graphs shall be included to support the detailed economic analysis that will form the basis of the conclusions.

In addition to this full-length report, the Contractor shall prepare executive summary materials as well as supporting PowerPoint presentations for use in briefing sessions and similar venues.

C. PERIOD OF PERFORMANCE

The period of performance shall be for seven (7) weeks from the date of the award.

D. PRINCIPAL PLACE OF PERFORMANCE

The principal place of performance under this award shall be at the Contractor's facility.

E. SPECIFIC REQUIREMENTS

There will be some travel associated with the SOW. This travel will be to the DOE Forrestal Building in Washington, DC.

E. DELIVERABLES

The Contractor shall submit a draft report to the COR, as specified in the Schedule of Deliverables, (below). The COR will organize a peer review of the draft report, and submit comments to the Contractor. In consultation with the COR, the Contractor shall formally address comments raised by the peer review, describing the disposition of each comment within 15 days of receipt of peer review comments. All deliverables and technical questions should be submitted to the COR, the single point-of-contact identified below.

1. The Contractor shall deliver a set of communications material summarizing the findings from the first two tasks
2. The Contractor shall deliver a full report of the findings, analyses, and recommendations as described in detail in Task 3 above.
3. The Contractor shall prepare executive summary materials as well as supporting PowerPoint presentations for use in briefing sessions and similar venues.

FutureGen 2.0 Oxy-Coal Combustion Carbon Capture Plant Pre-FEED Design and Cost

Prepared for:

U.S. Department of Energy
National Energy Technology Laboratory

Type of Report:	Phase 1 Final Technical Report
Reporting Period Start Date:	October 1, 2010
Reporting Period End Date:	September 31, 2011
Principal Author(s):	Tom Flanigan, URS Craig Pybus, ALPC Sonya Roy, ALPC Frederick Lockwood, ALE Denny McDonald, B&W PGG Jim MacInnis, B&W PGG
Date Report was Issued:	July 27, 2011
DOE Award Number:	DE-FE0005054

Prepared by:
Ameren Energy Resources

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ABSTRACT

This report summarizes the results of the Pre-Front End Engineering Design (pre-FEED) phase of a proposed advanced oxy-combustion power generation plant to repower the existing 200 MWe Unit 4 at Ameren Energy Resources' (AER) Meredosia Power Plant. AER has formed an alliance with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) for the design, construction, and testing of the facility, and has contracted with URS Corporation (URS) for preliminary design and Owner's engineering services.

The Project employs oxy-combustion technology – combustion of coal with nearly pure oxygen and recycled flue gas (instead of air) – to capture approximately 90% of the flue gas CO_2 for transport and sequestration by another Project.

Plant capacity and configuration has been developed based on the B&W PGG-ALPC cool recycle process firing high-sulfur bituminous coal fuel, assuming baseload plant operation to maximize existing steam turbine capability, with limited consideration for plant redundancy and performance optimization in order to keep plant costs as low as practical. Activities and preliminary results from the pre-FEED phase addressed in this report include the following:

- Overall plant thermal performance
- Equipment sizing and system configuration
- Plant operation and control philosophy
- Plant emissions and effluents
- CO_2 production and recovery characteristics
- Project cost estimate and economic evaluation
- Integrated project engineering and construction schedule
- Project risk and opportunity assessment
- Development of Project permitting strategy and requirements

During the Phase 2 of the Project, additional design details will be developed and the Phase 1 work products updated to support actual construction and operation of the facility in Phase 3. Additional information will be provided early in Phase 2 to support Ameren-Environmental in finalizing the appropriate permitting strategies and permit applications. Additional performance and reliability enhancements will also be evaluated in Phase 2 to try to improve overall project economics.

ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
ACI	American Concrete Institute
AER	Ameren Energy Resources
AL	American Air Liquide Holdings, Inc.
ALE	Air Liquide Engineering and Technology
ALLIUS	Air Liquide Large Industries US
ALPC	Air Liquide Process and Construction, Inc.
AQCS	Air Quality Control System
AR	Absorber Recirculation
Ar	Argon
ARRA	American Recovery and Reinvestment Act
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ASU	Air Separation Unit
AVT	All Volatile Treatment
B&PV	Boiler and Pressure Vessel
B&W PGG	Babcock & Wilcox Power Generation Group, Inc (a wholly-owned subsidiary of The Babcock & Wilcox Company)
BACT	Best Available Control Technology
BAHX	Brazed Aluminum Heat Exchanger
BCS	Boiler Control System
BFP	Boiler Feed Pump
BMCR	Boiler Maximum Continuous Rating
BMS	Burner Management System
BOD	Biochemical Oxygen Demand
BOP	Balance-of-Plant
BWG	Birmingham Wire Gauge
CAPEX	Capital Expense
CCS	Carbon Capture and Storage
CCW	Closed Cooling Water
CEDF	Clean Environment Development Facility
CEMS	Continuous Emissions Monitoring System
CHS	Coal Handling System
Cl	Chlorine or Chloride
CM	Construction Manager
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Chemical Oxygen Demand
COE	Cost of Electricity
CPU	Compression and Purification Unit
DC	Direct Current
DCCPS	Direct Contact Cooler – Polishing Scrubber
DCS	Distributed Control System

DOE	Department of Energy
DOR	Division of Responsibility
DSI	Dry Sorbent Injection
E&I	Electrical and Instrumentation
EHS&S	Environmental, Health, Safety and Security
EIS	Environmental Impact Statement
EIV	Environmental Information Volume
EI-XCL	B&W enhanced ignition burner design
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EPC	Engineer, Procure, Construct
EPRI	Electric Power Research Institute
FD	Forced Draft
FEED	Front End Engineering and Design
FEGT	Furnace Exit Gas Temperature
FeS	Iron Sulfide
FGA	FutureGen Alliance
FGD	Flue Gas Desulfurization
FRP	Fiberglass Reinforced Plastic
GOX	Gaseous Oxygen
GPS	Global Positioning System
GQCS	Gas Quality Control System
H_2	Hydrogen
H_2S	Hydrogen Sulfide
H_2SO_4	Sufuric Acid
HART	Highway Addressable Remote Transducer
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
Hg	Mercury
HGI	Hardgrove Grindability Index
HHV	Higher Heating Value
HMI	Human-Machine Interface
HP	High Pressure
HVAC	Heating, Ventilation, and Air Conditioning
HV-XCL	B&W High Velocity Dual Register Burner design
I&C	Instrumentation and Control
I/O or IO	Input/Output
I/P	Current to Pressure (Electropneumatic)
ID	Induced Draft or Inside Diameter
IGCC	Integrated Gasification Combined Cycle
IMS	Integrated Master Schedule
IP	Intermediate Pressure
L/G	Liquid-to-Gas
LCOE	Levelized Cost of Electricity
LOX	Liquid Oxygen
LP	Low Pressure

MACT	Maximum Achievable Control Technology
MBTU	Million British Thermal Units
MCC	Motor Control Center
MCR	Maximum Continuous Rating
ME	Mist Eliminator
MGD	Million Gallons per Day
MP	Medium Pressure
MTO	Material Take Off
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NOx	Nitrogen Oxides
NPSH	Net Positive Suction Head
NSR	New Source Review
O_2	Oxygen
OD	Outside Diameter
OFA	Overfire Air
OPC	Open Process Control
OPEX	Operation Expense
OSHA	Occupational Health and Safety Administration
OTF	Over-the-Fence
P&ID	Piping and Instrumentation Diagram
PC	Pulverized Coal
PCS	Plant Control System
PFD	Process Flow Diagram
PHE	Potomac-Hudson Environmental, Inc.
PJFF	Pulse Jet Fabric Filter
PL	Powdered Limestone
PM	Project Manager
PM	Particulate Matter
PR	Primary Recycle
PRB	Powder River Basin sub-bituminous coal
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance / Quality Control
RO	Reverse Osmosis
ROW	Right of Way
RTD	Resistance Temperature Detector
SCAH	Steam Coil Air Heater
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SPCC	Spill Prevention Control and Countermeasures Plan
SR	Secondary Recycle
STG	Steam Turbine Generator
T&D	Transmission and Distribution

TDH	Total Developed Head
TDS	Total Dissolved Solids
TOC	Total Organic Carbon
TPD	Tons per Day
TSA	Temperature Swing Adsorption
TS&M	Transport Store and Monitor
TSS	Total Suspended Solids
UF	Ultrafiltration
UPS	Uninterruptible Power Supply
URS	URS Corporation
VOM	Volatile Organic Matter
VSD	Variable Speed Drive
VWO-OP	Valves Wide Open, 5% Overpressure (STG Throttle condition)
WACC	Weighted Average Cost of Capital
WFGD	Wet Flue Gas Desulfurization
WFGD/DCC	Wet Flue Gas Desulfurizer-Direct Contact Cooler
WWTS	Wastewater Treatment System
ZLD	Zero Liquid Discharge

1.0 EXECUTIVE SUMMARY

Ameren Energy Resources (AER) has formed an alliance with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) to design, construct, and test an advanced oxy-combustion power generation plant at their Meredosia Power Plant site, and has contracted with URS Corporation (URS) for preliminary design and Owner's engineering services. The Project will repower the existing 200 MWe Unit 4 steam turbine generator, capturing most of its CO_2 for transport and sequestration by another Project.

This report covers the first phase – Pre-Front End Engineering Design (pre-FEED) – of the four-phase Project. The Project is divided into separate islands, as follows:

- Boiler/Gas Quality Control System (GQCS) – by B&W PGG
- Air Separation Unit (ASU)/Compression & Purification Unit (CPU) – by ALPC
- Balance of Plant (BOP) – by AER/URS

Oxy-combustion is the combustion of coal with nearly pure oxygen and recycled flue gas (instead of air), resulting in a flue gas byproduct that is primarily CO_2 instead of nitrogen, facilitating capture of the CO_2 so that it can be sequestered.

Plant capacity and configuration has been developed using the B&W PGG-ALPC cool recycle oxy-combustion process firing a high-sulfur bituminous coal, and assumes baseload operation to maximize existing steam turbine capability, with limited consideration given to plant redundancy and performance optimization. Additional performance and reliability enhancements will be considered in Phase 2. Resulting plant performance is summarized in Table 1-1. Plant emissions and CO_2 production are summarized in Table 1-2. With the exception of carbon monoxide (CO), which is no higher than a new conventional coal-fired plant, the emissions of the criteria pollutants are expected to be very low.

Table 1-1
Overall Plant Thermal Performance Summary

Steam Turbine Gross Generation to 138 kV Grid	202,766 kW
Total Plant Auxiliary Power	80,100 kW
Plant Net Generation	**122,666 kW**
Plant Net Heat Rate, HHV	**16,211 kJ/kWh (15,365 Btu/kWh)**
Net Plant Efficiency, HHV	**22.2%**

Based on annual average baseload normal operating conditions, as follows, including estimated equipment degradation for existing plant equipment:

- Ambient Temperature: 11.7 °C (53 °F) dry bulb, 8.9 °C (48 °F) wet bulb
- Oxy-combustion operation of Boiler at maximum continuous rating on 100% design fuel (Illinois No. 6 bituminous coal), with 1% boiler drum blowdown.

Table 1-2
Project Air Emissions and CO_2 Production Summary

Emissions Constituent	kg/hr (lb/hr)	g/GJ (lb/MBtu), HHV Basis	CO_2 Production	
CO	130.14 (286.90)	64.5 (0.15)	CO_2 Recovery	90% (by mass)
NO_x	≤ 12.80 (28.21)	≤ 6.32 (0.0147)	Mass flow	159,211 kg/hr (351 klbs/hr) 3,820 tonnes/day (4210 tpd)
VOM	≤ 3.13 (6.89)	≤ 1.55 (0.0036)		
PM (Total)	≤ 0.00026 (0.0006)	≤ 0.00013 (0.00000031)	Pressure	145 barg (2,100 psig)
SO_2	≤ 0.351 (0.774)	≤ 0.17 (0.0004)	Temperature	21.7 °C (71 °F)
Hg	≤ 0.0000027 (0.0000059)	≤ 0.0000013 (0.0000000031)	CO_2 content	≥ 99.7% (by mass, dry)

Based on operating conditions listed in Table 1-1, with all emissions from the CPU vent.

A Project Interface List and Division of Responsibility (DOR) document were developed to define the scope breaks between the islands. AER will own the entire repowered facility and will operate and maintain all systems within the plant except for possibly the ASU and the CPU, which may potentially be owned, operated, and maintained (in coordination with the remainder of the Plant) solely by AL under a services contract developed between AER and Air Liquide Large Industries US (ALLIUS).

With the exception of the ASU and CPU, plant design and operation are similar to a typical air-fired unit, with the following significant differences.

- The presence of highly concentrated O_2 and CO_2 streams within the plant require consideration of additional operational and safety issues.
- The ASU and CPU islands impose limitations on startup, shutdown, and load changing capabilities.
- Boiler, GQCS, and steam cycle are initially started and minimally loaded (to about 45% load) on air-firing, then transitioned to oxy-combustion when the ASU and CPU are ready.
- Heat integration between the steam cycle and other islands requires consideration of additional system design and operational limits.

A preliminary integrated schedule and cost estimate was developed for the overall power generation project, but excluding the pipeline and sequestration project. Estimates relied heavily on vendor quotations solicited specifically for this project. The total power generation project capital cost is estimated at $1.099 billion. AER is evaluating multiple economic scenarios using the Phase 1 performance and cost estimates, but results are not yet available.

A number of Project risks and potential enhancement opportunities have been identified during Phase 1 and will be further evaluated in Phase 2. Among the opportunities, specific performance improvements (e.g. auxiliary power) have been targeted to improve overall Project economics.

The Project continues to develop needed information on emissions, effluents, and consumables to support Ameren-Environmental in determining appropriate permitting strategies and completing permit applications. Information is also being provided to DOE's Environmental Impact Statement (EIS) contractor, PHE, for use in developing the EIS.

2.0 INTRODUCTION/PROJECT DESCRIPTION

2.1 *Project Description*

Ameren Energy Resources (AER), a subsidiary of Ameren Corporation, has formed an alliance to construct and test an advanced oxy-combustion power generation plant (FutureGen 2.0) at their Meredosia Power Plant site. The oxy-combustion Project will repower the 200 MWe Unit 4 steam turbine generator, capturing most of its CO_2 for transport and sequestration by another Project. AER has executed a Cooperative Agreement with the Department of Energy (DOE) for a federal cost share of approximately $590 million of ARRA funding for the Project. AER has formed an alliance with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) for design and construction of the major new equipment blocks to be installed and has contracted with URS Corporation (URS) to provide design services for the balance of plant (BOP), as well as Owner's engineering services.

The FutureGen 2.0 project will be designed for an expected 30 year life with respect to operability, maintainability and reliability. The oxy-combustion repowering project will utilize as much of the existing Unit 4 equipment and systems as possible, with the exception of the boiler (Boiler 6), which will be demolished. Due to the limited operating hours accumulated on Unit 4 since its construction in 1975, much of the existing equipment will be reusable.

2.2 *Project Schedule*

The Project is divided into four phases, as follows. This report addresses the results of Phase 1 only.

Phase 1: (October 1, 2010 – September 30, 2011) Pre-Front End Engineering Design (pre-FEED) work necessary to establish the initial plant performance, component sizes, preliminary specifications, and +/-20% Project cost estimate, along with initiation of Project permitting and NEPA processes. Completion of the following key documents/milestones is included in this Phase:

- Project Design Basis
- Process Flow Diagrams and Overall Mass and Energy Balances
- Project Cost Estimate and initial financial Pro Forma model
- Environmental information to support the NEPA process

- Integrated Phase 2 Project Schedule including Alliance Key Milestone Ties
- Phase 2 Project Management Plan
- Necessary commitments for Project Host Site
- Draft CO_2 off-take agreement with the Alliance
- Executed Cooperation and Technology Agreement with the Alliance

Phase 2: (October 1, 2011 – October 31, 2012) Completion of final FEED, NEPA process, and all major environmental permits needed for construction, along with +/-10% Project cost estimate.

Phase 3: (November 1, 2012 – April 30, 2016) Completion of required permitting, detailed engineering, procurement of materials and equipment, fabrication and delivery of materials and equipment to the site, construction of the Project, commissioning of equipment, plant start-up and initial plant operations.

Phase 4: (May 1, 2016 – December 31, 2018) Project testing, data collection and performance reporting.

2.3 *Project Scope Division of Responsibility*

In general, the project is divided into four islands:

- Boiler/Gas Quality Control System (GQCS) – by B&W PGG – with separate battery limits for Boiler and for GQCS.
- Air Separation Unit (ASU) – by ALPC
- Compression & Purification Unit (CPU) – by ALPC
- Balance of Plant (BOP) – by AER/URS

A Project Interface List has been developed and defines the general utilities and services provided between islands. These utilities and services are generally supplied to and from a single point at or within the battery limits of each island by the BOP, with distribution of those utilities beyond the interconnect point within each island by the individual island suppliers.

AER will own the entire repowered facility and will operate and maintain all systems within the plant except for possibly the ASU and the CPU, which may potentially be owned, operated, and maintained (in coordination with the remainder of the Plant) solely by AL under a services contract developed between AER and Air Liquide Large Industries US (ALLIUS).

2.4 *General Project Requirements and Design Philosophy*

Oxy-combustion is the combustion of coal with nearly pure oxygen and recycled flue gas (instead of air), resulting in a flue gas byproduct that is primarily CO_2 instead of nitrogen. Removal of nitrogen from the combustion process significantly reduces the flue gas mass flow and facilitates capture of high purity CO_2 from the flue gas so that it can be sequestered. The combustion oxidant (O_2) is supplied by the ASU, while the CPU purifies the flue gas.

Plant design is based on achieving successful oxy-combustion operation within project budget and schedule constraints, while achieving approximately the same summer design gross capacity (kW) as the existing Unit 4 design after accounting for existing turbine performance degradation. The engineering and design of the Project will ensure that all equipment and systems – regardless of scope of responsibility – are fully integrated systems, such that their function, operation, safety and performance are well coordinated and not impaired.

Boiler capacity and configuration has been generally set based on optimizing performance for the oxy-combustion operation mode, given the existing subcritical steam cycle. It should be noted that by reusing the existing subcritical cycle, the baseline heat rate (prior to oxy-combustion) is higher than a typical new conventional plant and will therefore detract from the oxy-combustion cycle performance that could otherwise potentially be achieved with a newer plant.

The ASU and CPU are each designed with a single 100% capacity train, sized to accommodate 100% boiler MCR load at summer design temperatures. Additional performance and reliability enhancements will be considered in Phase 2.

2.5 *Oxy-Combustion Process Description*

Figure 2-1 shows the oxy-combustion process schematic selected for the FutureGen 2.0 project. The combustion process employs the B&W PGG-ALPC cool recycle process firing a high sulfur bituminous coal. The entire system is integrated for maximum optimization, given the existing steam cycle and equipment. Heat from the ASU is incorporated into the condensate cycle, while heat from the steam cycle is used for flue gas reheating and other process heat loads. Because the FutureGen 2.0 application involves repowering an existing steam turbine, turbine design limits restrict the amount of heat which can be recovered from the oxy-combustion process and utilized in the power cycle to improve performance. Consequently, heat integration performance improvements that could be realized for a new oxy-combustion plant design will likely not be achieved for this Project, unless extensive steam turbine upgrades can be economically justified.

In the cool recycle process, hot gas leaves the boiler and passes through a regenerative advanced quad-sector (patent pending) secondary and primary recycle heater (aka airheater). This recycle heater is internally arranged to prevent any leakage of the oxidant fed from the ASU into the flue gas.

Following the dry sorbent injection for SO_3 removal, the flue gas passes through the pulse jet fabric filter (PJFF) where particulate matter (PM) is removed. From the PJFF the flue gas pressure is boosted by the induced draft fans and it enters the wet flue gas desulfurization (WFGD) absorber where most of the SO2 is removed.

Following the WFGD the saturated flue gas flow splits. One stream passes through a gas reheater to avoid downstream moisture condensation and its pressure is boosted by the secondary recycle (SR) fans. Oxidant (nearly pure oxygen) is introduced into the secondary recycle flow after the SR fans via Floxynators™ before re-entering the recycle heater for heating prior to the boiler windbox. The SR fans control the secondary flow to the boiler. The remaining flow leaving the WFGD passes through a direct contact cooler polishing scrubber (DCCPS) where moisture is reduced and most of the remaining SO_2 is removed.

The saturated gas leaving the DCCPS is reheated to avoid downstream moisture condensation and is again split with one stream flowing to the compression and purification unit (CPU), and the other supplying the primary recycle (PR) fans. The PR fans provide the flow required to dry and convey the pulverized coal to the burners. Oxidant is preheated and introduced into the primary recycle flow after the recycle heater via Floxynators™. A portion of the primary recycle bypasses the recycle heater to temper the hot primary to each pulverizer as needed to achieve the temperature required to dry the coal and achieve the desired pulverizer outlet temperature. The oxygen concentration in this stream is controlled to mitigate risk of combustion in the pulverizers or coal pipes. Oxidant is also injected directly into the burners to control combustion and the remaining oxidant is mixed into the secondary recycle as previously described.

When air firing (during start-up and shut-down), the secondary recycle stream is isolated by dampers and all of the gas leaving the WFGD flows to the stack as in a conventional air-fired design. The primary and secondary recycle control dampers are closed and, through their air intakes, the SR and PR fans provide fresh air to the recycle gas heater. The DCCPS and its outlet gas reheater are not in service in this mode.

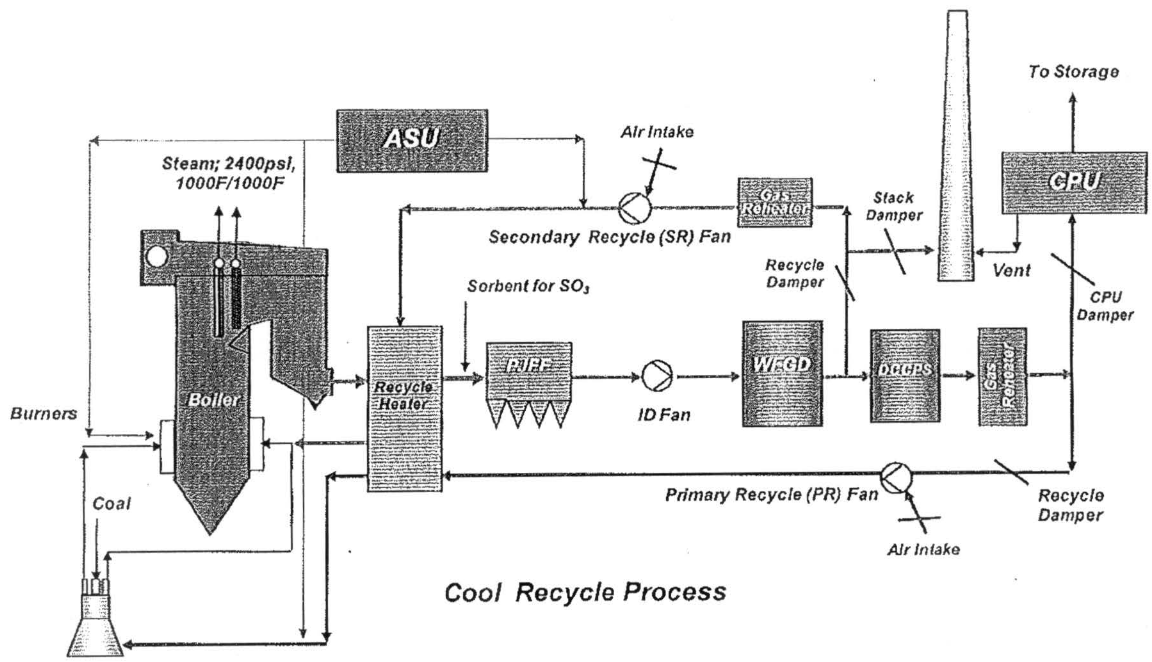

Figure 2-1
Oxy-combustion Cool Recycle Process Schematic

3.0 PROJECT DESIGN

This section describes the preliminary design and performance of Project as established during Phase 1.

3.1 *Plant Performance*

All performance is based on annual average operating conditions, as follows:

- Ambient Dry Bulb Temperature: 11.7 °C (53 °F)
- Ambient Wet Bulb Temperature: 8.9 °C (48 °F)
- Baseload operation of all islands, including the following
    - Oxy-combustion operation of Boiler at maximum continuous rating on 100% design fuel (Illinois No. 6 bituminous coal), with 1% boiler drum blowdown.
    - Steam turbine at VWO-OP conditions
    - ASU at 100% load, normal operating mode
    - CPU at 100% load, normal operating mode, discharging to the CO_2 pipeline
    - All heat integration between islands operating normally, per the conditions established in the Project Design Basis Document.

Plant performance is presented in Table 3-1. Based on an evaluation of the limited Unit 4 performance data available, the Phase 1 performance figures reported here include an estimated 3.1% degradation from new and clean turbine performance reported on the original turbine heat balances. Section 5.0 discusses the underlying basis for this performance and potential changes in plant design which could significantly improve overall performance.

3.2 *Plant Effluents and Emissions*

3.2.1 Air Emissions

Table 3-2 summarizes the air emissions for the Project under average annual operating conditions. With the exception of carbon monoxide (CO), which is no higher than a new conventional coal-fired plant, the emissions of the criteria pollutants (SO_2, NOx, PM, VOM, Hg) are expected to be very low.

Table 3-1
Overall Oxy-PC Plant Thermal Performance

Steam Turbine Generator Output (gross)	203,580 kW
Generator Step-Up Transformer Losses	814 kW
Steam Turbine Gross Generation to 138 kV Grid	202,766 kW
Plant Auxiliary Power	80,100 kW
Plant Net Generation	**122,666 kW**
Boiler Heat Output	1,766 GJ (1,674 MBtu/hr)
Boiler Fuel Efficiency (HHV)	88.83 %
Fuel Heat Input (HHV)	1,989 GJ (1,885 MBtu/hr)
Coal Consumption	81,420 kg/hr (179,500 lb/hr)
Plant Net Heat Rate, HHV	**16,211 kJ/kWh (15,365 Btu/kWh)**
Net Plant Efficiency, HHV	**22.2%**

All performance based on following:

- Average Annual Ambient Dry Bulb Temperature: 11.7 °C (53 °F)
- Average Annual Ambient Wet Bulb Temperature: 8.9 °C (48 °F)
- Baseload operation of all islands, including:
  - Oxy-combustion operation of Boiler at maximum continuous rating on 100% design fuel (Illinois No. 6 bituminous coal), with 1% boiler drum blowdown.
  - Steam turbine at VWO-OP conditions
  - ASU at 100% load, normal operating mode
  - CPU at 100% load, normal operating mode, discharging to the CO_2 pipeline
  - All heat integration between islands operating normally, per the conditions established in the Project Design Basis Document.
- Estimated equipment degradation included for existing plant equipment.

Table 3-2
Project Air Emissions

Emissions Constituent	kg/hr (lb/hr)	g/GJ (lb/MBtu), HHV Basis
CO	130.14 (286.90)	64.5 (0.15)
NO_x	≤ 12.80 (28.21)	≤ 6.32 (0.0147)
VOM	≤ 3.13 (6.89)	≤ 1.55 (0.0036)
PM (Total)	≤ 0.00026 (0.0006)	≤ 0.00013 (0.00000031)
SO_2	≤ 0.351 (0.774)	≤ 0.17 (0.0004)
SO_3	≤ 0.753 (1.660)	≤ 0.374 (0.00087)
HCl	≤ 0.042 (0.092)	≤ 0.021 (0.000048)
HF	≤ 0.00029 (0.00065)	≤ 0.00015 (0.00000034)
Hg	≤ 0.0000027 (0.0000059)	≤ 0.0000013 (0.0000000031)

Current estimates for permitting purposes, based on average annual baseload operating conditions, with all emissions from the CPU vent.

3.2.2 Liquid and Solid Effluents

The major Project effluents at average annual operating conditions are summarized in Table 3-3.

Table 3-3
Project Effluents

Solid Effuents	Effluent Rate
Bottom Ash (wet)	1,860 kg/hr; 44.6 tonnes/day (4,100 lb/hr; 49.2 tpd)
Fly Ash (wet)	9,300 kg/hr; 223.2 tonnes/day (20,500 lb/hr; 246.0 tpd)
Gypsum (wet)	21,320 kg/hr; 512 tonnes/day (47,000 lb/hr; 564 tpd)
Water/Wastewater Treatment Solids	10.4 kg/hr; 250 kg/day (23 lb/hr; 552 lb/day)
Liquid Effuents (refer also to Water Balance)	**Effluent Rate**
Cooling Water (once-thru and tower blowdown)	21,833 lpm; 31,515 m^3/day (5,781 gpm; 8,325 kgal/day)
Process Wastewater	660 lpm; 950 m^3/day (174.3 gpm; 251.0 kgal/day)
Intake Screen Backwash	147 lpm; 212 m^3/day (38.8 gpm; 55.9 kgal/day)
Sanitary Sewage	7.2 lpm; 10.4 m^3/day (1.9 gpm; 2.74 kgal/day)
Waste Oil Disposal (off-site disposal)	3.8 m^3/day (994 gal/day), max design

Based on operation of Unit 4 only.

3.2.3 CO_2 Recovery, Production, and Quality

During average annual operating conditions, the expected CO_2 recovery and production for the Project, along with CO_2 product quality at the CPU battery limits are as indicated in Table 3-4.

Table 3-4
CO_2 Recovery, Production, and Quality

CO_2 Recovery (mass basis)	90%
Mass flow (CO_2)	159,211 kg/hr (351 klbs/hr) 3,820 tonnes per day (4,210 tpd)
Pressure	145 barg (2,100 psig) *
Temperature	21.7 °C (71°F)
CO_2 content	≥ 99.7% (by mass, dry basis)

* Current pipeline delivery pressure specification is 145 barg (2,100 psig). However, CPU Process and performance calculations have actually been based on 152 barg (2,200 psig) for Phase 1.

3.3 *Plant Control*

3.3.1 Startup

ASU Startup

Cold Start-up (Liquid Levels Maintained)

If the ASU has been shut down for a short period of time, the plant will still be at cryogenic temperatures and maintaining liquid levels. In this case the plant can be restarted fairly quickly by starting the Main Air Compressor, establishing clean dry air flow to the cold box through the adsorbers, and pressurizing the cold box. Once the cold box is pressurized, the expander can be started to produce the temperature drop required for cryogenic separation, product purity and subsequent production. The cryogenic pumps are then started and the facility placed on line.

Warm Start-up (After a Derime)

Starting up the ASU after a derime is essentially the same as a Cold Start-up with the exception of the plant being warm and requiring a longer period of time for cooldown.

Steam Turbine and BOP Startup

To support operation and warmup of the ASU, the following balance of plant (BOP) systems and equipment will initially be placed in service:

- HP and LP Service Water pumps
- Auxiliary boiler (including auxiliary boiler feed pumps and deaerator)
- ASU steam supply and condensate return systems
- Plant air compressors (if not already in normal operation)
- ASU/CPU circulating water pumps (1 pump operation initially)
- ASU/CPU cooling tower fans (number dependent on ambient conditions)

Other BOP systems will remain in their normal shutdown configurations until the ASU startup nears completion and the remainder of the plant can be started. The following additional BOP systems and components will then be placed in service:

- Fuel oil system to support boiler lightoff
- Coal handling systems (as needed to refill the boiler coal silos)

- Closed cooling water system
- Main and DCCPS circulating water pumps (1 pump operation initially for each service)
- Main and DCCPS cooling tower fans (number dependent on ambient conditions)
- Steam turbine oil systems
- Makeup water system pumps and treatment equipment (pumps running but in recirculation mode, provided plant systems are already filled)
- Wastewater system pumps and treatment equipment (pumps in automatic)

To initiate flow to the boiler, the Condensate and Feedwater systems are placed in service. Initially, a single pump in each service will support plant operation, with flow recirculated to the condenser and deaerator as necessary. Additional pumps will be started as system flow warrants. The all-volatile treatment (AVT) chemical feed systems will be placed in service to establish and maintain feedwater chemistry.

Besides supplying the ASU steam requirements, the auxiliary boiler will also initially provide steam for main boiler sootblowing and air preheating (in the SCAH). As sufficient steam pressure is developed in the boiler to maintain the auxiliary steam system pressure, the auxiliary boiler can be shut down. Once the auxiliary steam system is running on its normal supply from the main boiler, seal steam is applied to turbine glands and pegging steam flow to the deaerator is initiated. With turbine seal steam established, the condenser vacuum system will be placed in service to begin drawing condenser vacuum.

When sufficient condenser vacuum is achieved, and as boiler steam pressure and temperature continue to increase, main steam turbine operation will be initiated. Turbine warmup will be controlled following existing turbine startup procedures. When rated turbine speed (3,600 rpm) has been reached, the generator will be synchronized and connected to the grid. The turbine will initially be loaded to its minimum stable level, and then gradually ramped up to full load in coordination with the boiler.

Feedwater heaters (except for the deaerator) will initially be bypassed. As turbine temperatures increase, HP heater steam extraction flows will be initiated and the heaters placed in service, followed by the LP heaters. Additional steam and feedwater supplies from the steam cycle to the GQCS, ASU, and CPU will commence as those systems reach their minimum operating limits for heat integration.

Boiler Startup

During the ASU startup process the boiler startup is initiated at the appropriate time to coordinate having the boiler ready for transition to oxy-combustion when the minimum acceptable oxidant purity is available. Boiler and steam cycle startup are essentially the same as with air firing up to the transition load. As indicated in Figure 2-1, the stack damper and PR and

SR fan air intake dampers are fully open, and the PR and SR recycle flow control dampers and CPU dampers are fully closed for air operation.

Boiler Startup – Air Firing

The following describes the major steps in boiler startup but is not intended to be a comprehensive description. Boiler feedwater treatment must be in operation and ready to supply the boiler with water and the steam drum must be filled to startup level. After verification that all boiler auxiliary systems are ready for starting and all vent and drain valves are in the required startup positions, the fans are started and the furnace purged with burner registers at their predetermined light-off position. Once the furnace purge is complete, the lighters for the first burner group can be ignited. The heat input from the lighters is raised and additional burner group lighters are brought into service until the required steam conditions for turbine roll are achieved. After the fuel flow increases to match the minimum purge air flow, the burner registers can be moved from the light-off position to the cooling position.

Once steam conditions for turbine roll are achieved, the steam turbine is rolled and warmed (soaked) to relieve thermal stresses due to initial temperature differences within turbine components. When the boiler and turbine components have reached the desired temperatures, the first pulverizer can be started and coal firing initiated.

Because the unit is designed to be able to achieve full boiler maximum continuous rating (BMCR) with the design, Illinois #6, coal with two pulverizers in service and the third as spare, care must be taken to reduce the lighter input as the coal input increases to avoid excessive upsets in boiler heat input. Air flow is controlled appropriately to maintain the desired excess air (oxygen) at the boiler outlet under these conditions. Once the pulverizer is started and coal flow increased to the minimum pulverizer load (about 30% of full pulverizer input), all lighters except those associated with the first pulverizer group are backed out, and the unit is operating in a stable condition, the process is ready for transition to oxy-combustion. The minimum heat input may be as low as 30% to 35% of BMCR heat input, but for initial purposes, 45% of BMCR heat input is being assumed as the transition load. Since flue gas emissions prior to oxy-combustion operation and CPU startup are discharged to atmosphere via the startup stack, it is advantageous to transition to the oxy-combustion mode at as low a load as practical to minimize overall air emissions. The final minimum transition load will be established during initial unit tuning.

Transition to Oxy-combustion

Once the boiler has achieved stable operation at the transition load, the transition from air firing to oxy-combustion can commence. With the ASU ready to supply oxidant at the minimum oxygen purity, the process can begin the transition by initiating flue gas recycling. Lower quality oxygen can be used during boiler startup to reduce startup time but may extend the time required to reach full load if the time required for the ASU to reach full purity is greater than the time required to ramp the boiler and steam turbine to full load. The actual quality and availability of oxidant flow depends on the ASU design, but the requirements are partially driven by the tolerance of the CPU to accept the additional argon and nitrogen concentrations in the flue gas during CPU startup. The full transition will also depend upon the readiness of the CPU to accept the flue gas and produce CO_2 to the required pipeline purity. Both the ASU and CPU use a cryogenic process so the startup time from cold is governed by the time required to achieve the necessary cold box conditions for oxygen separation in the ASU and CO_2 separation in the CPU. Overlapping the ASU, boiler, and CPU not only reduces the overall startup time but minimizes air emissions.

Prior to the initiation of the transition, the SR and PR fan air intake control and isolation (tight shut-off) dampers are fully open and the SR and PR flue gas flow control dampers are fully closed. The transition to oxy-combustion begins by first adding oxidant to the operating burners in order to maintain stable and attached flames throughout the process. The transition is initiated by opening the SR flow control damper gradually allowing flue gas to be drawn into the SR fan inlet. As the recycled flue gas flow increases, oxidant is added to the secondary stream to maintain a safe oxygen level at the boiler exit. Once the SR flow control damper is fully open, the SR fan inlet air control damper is gradually closed, increasing the recycled flue gas flow into the SR fan inlet flue.

Once the secondary stream has been fully transitioned, transition of the primary stream commences using the same procedure by gradually opening the PR flow control damper. As the primary stream composition transitions from air to recycled flue gas, the oxygen in the primary stream to the pulverizers (after the recycle heater, aka airheater) is maintained at a prescribed set point. When the PR flow control damper is fully open, the PR fan air intake control damper is gradually closed. Once both the PR and SR fan air intake control dampers are fully closed the boiler process is in full oxy-combustion mode and the PR and SR fan air intake isolation (tight shut-off) dampers can be closed.

If the desired recycle flue gas flow is not achieved when the SR and PR fan air intake control dampers are fully closed and the flue gas recycle dampers are fully open, the stack inlet damper can be gradually closed to force additional flue gas to the SR and PR fan inlets. Flue gas flow to the stack must be maintained until the CPU is in service and ready to accept the flue gas.

When operating in equilibrium, the flue gas flow to the CPU (or stack) is equal to the sum of the oxidant (air and/or oxygen) added, any air infiltration, and the products of combustion less the constituents removed by the WFGD and DCCPS.

Once the boiler process is in full and stable oxy-combustion mode, (estimated to require 30 to 45 minutes), and the CPU is ready, the flue gas can be transitioned from the startup stack to the CPU. This is accomplished by first opening the CPU isolation (tight shutoff) damper (the CPU flow control damper is closed). The CPU flow control damper is then gradually opened, which will draw flow into the CPU and away from the startup stack. The CPU will maintain appropriate conditions to avoid an upset to the boiler process or the pipeline. Once the CPU flow control damper is fully opened, the stack flow control damper is gradually closed redirecting all remaining flow from the stack through the DCCPS, PR gas reheater, and to the CPU. During the transition the steam flow to the PR gas reheater will be modulated to maintain the outlet temperature above the dew point.

Unit load demand controls the PR flue gas demand to satisfy the needs of in-service pulverizers and SR flow is controlled to satisfy total mass flow to the boiler for combustion and heat transfer. SR gas flow is also used to control reheat outlet steam temperature by varying furnace and convection pass absorption. The SR and PR flows are measured and temperature compensated based on the densities of the air and oxygen/recycle gas flow streams. This density compensation accounts for the changing constituents of the SR and PR streams with air, oxygenated flue gas, and a mixture of the two.

The ASU Demand is the oxidant flow (a function of oxygen purity) required to deliver the difference between the theoretical stoichiometric oxygen requirement corresponding to the total Btu input plus the target excess oxygen and the oxygen available from incoming air and oxygen in the recycled flue gas. The ASU Demand is trimmed to maintain the target excess oxygen at the boiler outlet.

The oxidant flow to the oxidant injectors, called Floxynators™, is controlled to maintain an oxygen concentration by volume in the SR and PR streams downstream of the injection points. The total oxidant to the in-service burners is a proportional function of the total oxidant demand on the unit. The oxidant flow to the individual burners associated with a pulverizer is a function of that individual pulverizer demand compared to the total firing rate demand. Distribution between burners is preset during commissioning using valves on each burner to optimize combustion.

The local concentration of oxygen in the recycle flue gas downstream of the Floxynator™ must remain below maximum oxygen concentration limits under all circumstances. The demand for Total Oxidant is coordinated between the boiler and the ASU.

3.3.2 Load Changing

Starting an additional pulverizer under oxy-combustion conditions is similar to starting a pulverizer under normal air firing. The first step is to confirm that the burner registers associated with the pulverizer to be placed in service are at light-off position. The associated lighters are then placed in service on these burners. Oxidant flow demand is temporarily increased to help maintain flame stability. Primary flow through the pulverizer is established when its burner line shutoff valves are opened, increasing the required PR flow. The oxygen concentration in the PR stream is maintained to its prescribed setpoint which, along with the additional oxidant to the burners, will increase excess oxygen. The increased recycle demand results in a temporary decrease in flow to the CPU which maintains a backpressure equivalent to that which would otherwise be provided by the stack.

After the pulverizer and feeder are started, oxidant flow to the corresponding burners is initiated. The additional coal flow will automatically back down the other in service feeder(s) to maintain heat input and redistribute the oxidant to the in-service burners based on pulverizer load. As stable conditions are achieved at the new total heat input, oxidant to the burners is returned to its normal set point and excess oxygen at the boiler outlet is trimmed.

Recycled flue gas and oxidant flow demands will follow changes in boiler heat release demands similar to normal air-fired systems. Oxidant flow to the burners is temporarily increased during transient conditions until steady state load conditions are achieved. Recycle flue gas flow leads oxidant flow which leads fuel flow on load increases. The process is opposite for a load decrease with fuel flow decrease leading oxidant flow decrease which leads recycle flue gas flow decreases.

The individual load change capabilities for the boiler, GQCS, ASU, and CPU are sufficient to support the overall plant load change requirement.

3.3.3 Shut Down

Transition from oxy-combustion back to air firing is the reverse of the transition procedure described in Section 3.3.1. Load is reduced to the transition load point , the gas flow to the CPU is transitioned back to the startup stack, and the CPU is shut down. The PR stream is transitioned back to air first, followed by the transition of the SR stream. First the fan air intake isolation damper is opened while the fan air intake control damper remains closed. The air intake control damper is then gradually opened allowing air into the fan inlet flue. As air mixes with the recycled flue gas, oxidant demand to the corresponding Floxynator™ decreases, as will the total oxidant demand to the ASU. Once the fan air intake dampers are fully open, the recycle flue gas control damper is gradually closed until the fan is supplying only air to the process. At this point the oxidant demand to that stream will be zero and the associated Floxynator™ is shut down. Once both the primary and secondary streams have reverted to air and no oxidant is being injected into the recycle streams, the oxidant flow to the in-service burners is decreased and stopped. From this state the lighters for the in-service pulverizer are ignited as the pulverizer load is decreased to minimum and then shut down followed by the PR fans. Load is further decreased to turbine trip load and the turbine is shut down. The lighters are shut off and the furnace is purged using the SR and ID fans. Once the purge is completed these fans are also shut down, unless they are needed to increase the boiler cool down rate.

3.3.4 Major Trips

Master Fuel Trips

Master fuel trips occur when the interlock system detects an unsafe condition such as loss of ignition, loss of air or oxidant flow, high or low boiler steam drum level, or turbine trip. The operator may, at his discretion, also initiate a master fuel trip. In either case, all fuel flow and sources of ignition are stopped immediately, the CPU is bypassed to the stack, and the furnace is purged. All pulverizers are stopped, the PR fans are stopped, and oxidant flow to the burners and primary Floxynators™ is stopped. Oxidant to the secondary Floxynator is continued to maintain an O_2 concentration of 21% by volume while the SR fan air intake control damper is open and the SR flue gas flow control damper is closed. Once the SR stream has reverted to air the oxidant flow to the secondary Floxynator™ is stopped. The ID and SR fans continue to operate for furnace post-purge.

The control system will close all attemperator and sootblower supply valves. The air flow shall not be increased by deliberate manual or automatic control action. If the air flow is above the purge rate, it shall be permitted to be decreased gradually to the purge rate for a post-firing purge. If the air flow is below the purge rate at the time of the trip, it shall be continued at the existing rate for 5 minutes and then increased gradually to the purge rate air flow and held at this value for a post-firing unit purge. All other current NFPA 85 standards must also be satisfied. Usually the unsafe condition can be corrected and the fuel reignited with little delay following a furnace purge.

Forced Shutdown

Forced shutdown procedures are used to remove the unit from service as quickly as possible, but in a more controlled manner than with the Master Fuel Trip. This procedure requires that the turbine control valves be used to control the load down to the Transition load. Once at Transition the CPU flow is reverted to the stack and the CPU is shut down. Once the flow to the stack has been reestablished, the unit is reverted to air firing and the turbine load is further reduced to the turbine trip load. After the turbine is removed from service, all fuel is stopped and the unit is purged.

3.4 *Power Block Systems*

3.4.1 Boiler and Auxiliaries

The pulverized coal boiler plant is designed to provide the required steam flow to generate a nominal 200 MWe (gross) with the steam power cycle described in Section 3.7 below. The resultant boiler performance parameters are indicated in Table 3-5. The boiler and GQCS process schematic is shown in Figure 2-1 in Section 2.5.

Table 3-5
Overall Boiler Performance

Main Steam Flow	644,150 kg/hr (1,420.1 klb/hr)
Reheat Steam Flow	555,920 kg/hr (1,225.6 klb/hr)
Feedwater Flow	650,540 kg/hr (1,434.2 klb/hr)
Main Steam Outlet Pressure	175.9 barg (2,550 psig)
Main Steam / Reheat Steam Outlet Temperatures	542.8 / 540.6 °C (1,009 / 1,005 °F)
Total Heat Output	1,766 GJ/hr (1,674 million Btu/hr)
Total Heat Input	1,989 GJ/hr (1,885 million Btu/hr)
Fuel Flow	81,420 kg/hr (179.5 klb/hr)

Boiler

The boiler is a pulverized coal (PC) fired 200 MW (gross) boiler. It is 9.45 m (31'-0") wide, 11.58 m (38'-0") deep, and the height from the bottom inlet headers to the roof is 38.94 m (127'-9"). It is a balanced draft Carolina type subcritical Radiant Drum Boiler designed for variable turbine throttle pressure operation. This unit has a series downpass arrangement, as depicted in Figure 3-1, and will vary the flue gas recycle rate for reheat steam temperature control. In addition a spray attemperator located at the inlet to the reheater will be used for reheat steam temperature control during boiler transient conditions as well as for emergencies. The boiler is designed to burn the specified range of Illinois #6 coal and will utilize #2 fuel oil for the igniters.

Feedwater enters the bottom header of the economizer. Water passes upward through the economizer tube bank, through stringer tubes which support the economizer and primary superheater banks, and discharges to the economizer outlet headers. From the outlet headers, water flows into piping which connects to the steam drum. By means of natural circulation, the water flows down through downcomer pipes and supply distributor tubes to the lower furnace wall headers. From the furnace wall headers, the water/steam mixture rises through the furnace tubes to the upper enclosure headers. The flow then passes through riser tubes back into the steam drum.

The water and steam mixture in the steam drum is separated by cyclone steam separators which provide essentially steam-free water in the downcomers and water-free steam to the drum outlet connections. The steam is further purified by passing through the primary and secondary steam scrubbers within the steam drum.

Steam from the steam drum flows through multiple connections to the headers supplying the furnace roof tubes and pendant convection pass sidewall tubes. From the furnace roof outlet headers steam passes to the enclosure of the horizontal convection pass. The steam flows down horizontal convection pass enclosure and into the outlet headers which are also the inlet headers to the primary superheater.

Steam flow rises through the primary superheater and discharges through its outlet header and through two (2) connecting pipes each equipped with a spray attemperator.

The steam then enters the secondary superheater inlet header and flows through the secondary superheater sections to the outlet header nozzle which connects to the main steam line.

Steam returning from the turbine passes through the reheat attemperator located in the inlet piping to the reheat superheater. It then flows through the pendant reheater sections and exits the reheater through the outlet header which has a single end outlet.

Superheater and Reheater Material Selection

This unit has two vertical secondary superheater banks and the primary superheater is comprised of four horizontal banks in the downpass and one vertical outlet bank. Note that this unit does not have a platen superheater.

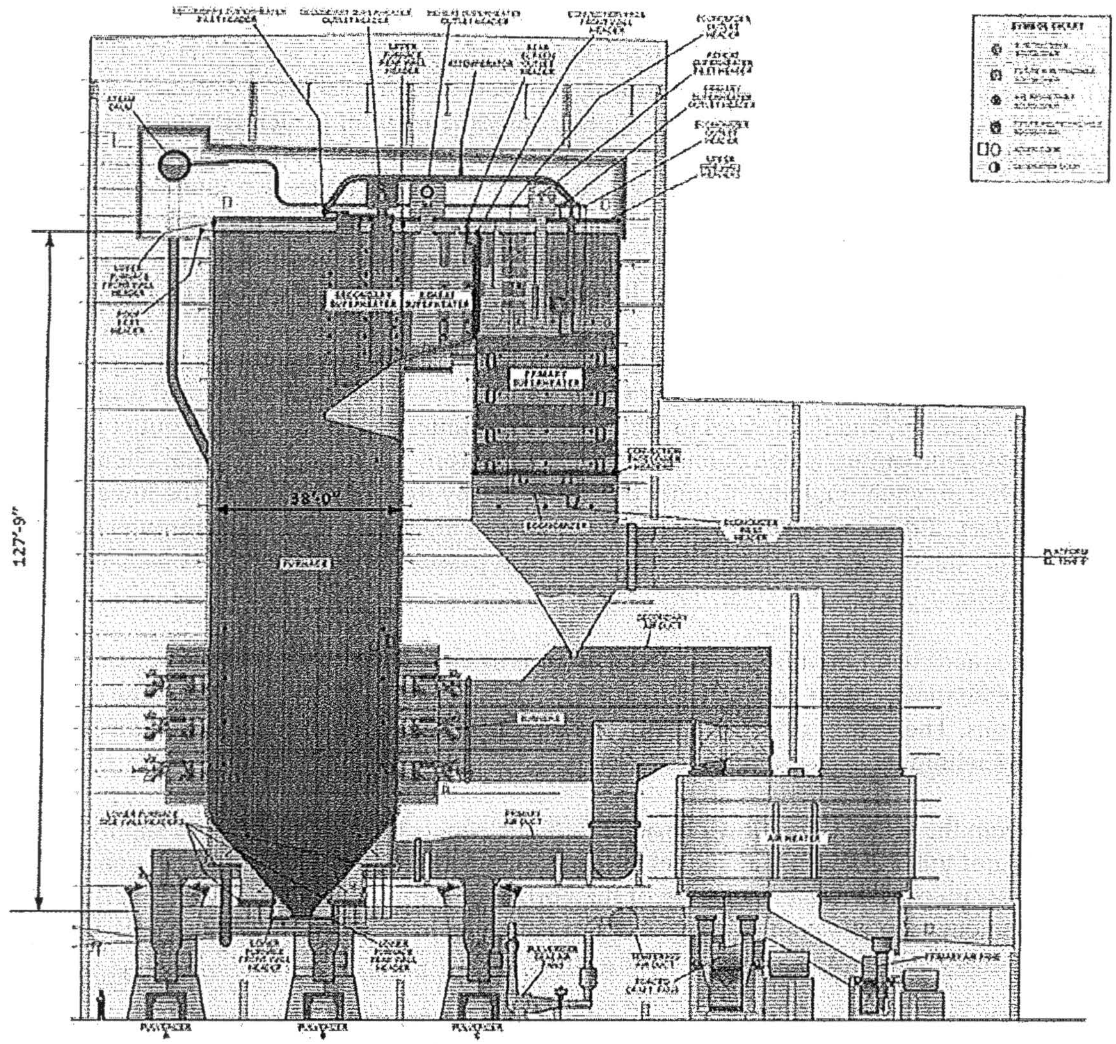

Figure 3-1
Carolina Radiant Drum Boiler with Series Downpass

Several factors are considered in the selection of the superheater and reheater tube materials. The material and tube thickness must not only be adequate to meet the requirements of ASME Code, but gas side and steam side corrosion must also be considered in the selection of the tube materials.

Since the Illinois #6 coal contains a significant amount of sulfur and chlorine, both of which contribute to elevated corrosion potential in the superheater and reheater banks, the material selection should give careful consideration to gas side corrosion. As a result of B&W PGG's gas side corrosion analysis, higher grade materials (SA213TP310HCbN and SA213TP310H) were selected for the outlet portions of the secondary superheater and reheater banks.

Since all of the recycle gas has Trona injected to remove SO_3 and also passes through the wet scrubber (WFGD absorber) and the primary recycle gas also passes through the direct contact cooler/polishing scrubber (DCCPS), the concentration of SO_2 and SO_3 in the recycle gas is very low. Because the SO_2 and SO_3 have been removed from the recycle gas it dilutes the SO_2 and SO_3 concentration resulting from the combustion of the coal and oxidant in the furnace. This results in concentrations of SO_2 and SO_3 that are essentially the same as would be produced when firing the same fuel with air. Therefore corrosion rates are expected to be very similar to an air fired boiler burning this type of coal.

Due to the selection of SA213TP310HCbN and SA213TP310H (materials that also have a strong steam-side corrosion resistance) for the outlet portions of these banks, I.D. oxidation and exfoliation is not a concern.

Recycle Heater

One (1) quad-sector regenerative recycle preheater (aka air heater), size 31-VI-86, is provided. The recycle heater is sized to reduce inlet flue gas from approximately 321 °C (610°F) to approximately 177 °C (350°F), excluding correction for leakage, at the BMCR load when firing the typical Illinois #6 coal.

The arrangement of the sectors (patent pending) is used to prevent oxygen from leaking from the recycle gas side to the flue gas side. Oxygen is not only costly to produce in the ASU but it must also then be removed in the CPU.

As shown in Figure 3-2, the secondary sector is isolated from the gas sector by two primary sectors on either side. Since the primary recycle stream is at a higher pressure than either the secondary or the gas side, leakage occurs from the primary to secondary and from the primary to the gas side. As a result, no leakage occurs from the secondary to the gas side. Since the secondary recycle stream is the only stream that is oxygenated upstream of the recycle heater, no injected oxygen is lost to the gas stream. The oxygen for the primary stream is injected downstream of the recycle heater.

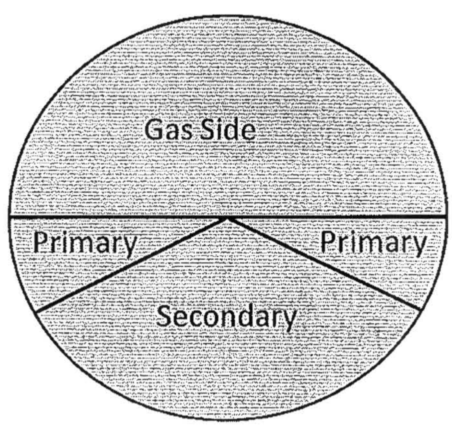

Figure 3-2
Recycle Heater (Plan View)

Although no injected oxygen is lost to the gas stream in this recycle heater sector arrangement, the overall leakage to the gas is increased due to the high pressure differential between the primary sectors and the gas sector. In addition, generally leakage rates are higher when in oxy-firing mode due to the higher densities of the gases as compared to air firing. Work is in progress to minimize the impact of this leakage on the capital and operating expense of the plant. It is believed that the oxygen loss resulting from use of a conventional trisector would be more costly than the impact of the leakage. Further evaluation for this plant will be made to confirm that during Phase 2.

Pulverizers

Three (3) B&W-89N pulverizers, depicted in Figure 3-3, with externally manually adjustable classifier vanes, are located along the boiler left side wall. These pulverizers are sized to meet the expected Boiler Maximum Continuous Rated (BMCR) load requirements with one mill out of service while firing the specified range of Illinois #6 coals. Each pulverizer feeds six (6) burners, which is one level of burners (front and rear wall). Coal is dried in the pulverizers and conveyed through the burner lines to the burners with recycle gas. Functionally, the coal pulverizers operate in the oxy firing mode the same way that they do in air firing mode.

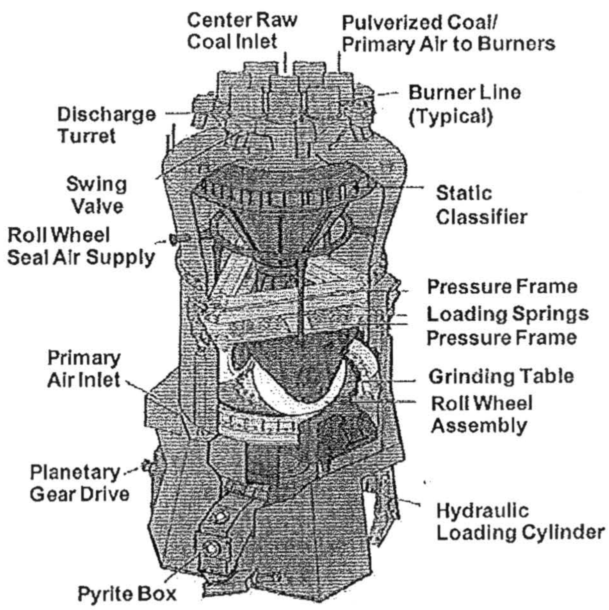

Figure 3-3
B&W Pulverizer

These pulverizers are also equipped with B&W's Auto-Spring^{TM} automatic wheel loading system which allows for variable adjustment of the spring load exerted down against the roll wheel assemblies. When operating the pulverizer at low coal flows, spring pressure is automatically reduced to minimize mill vibration. At high coal flows, spring pressure increases to improve grinding efficiency. This system was implemented due to the significant range of grindability (HGI) of the Illinois #6 coal. It also improves the turndown capability of the pulverizers which is beneficial at the air to oxy transition load.

Burners

There are eighteen (18) B&W HV-XCL™ low NO_X burners, depicted in Figure 3-4, in three elevations on the front and rear walls of the furnace. It should be noted that each pulverizer supplies all of the burners on the front and rear wall of a given elevation, thus regardless of which pulverizer(s) is out of service, the burners in operation will always be directly opposed. This enhances combustion stability and encourages high combustion efficiency.

Each burner has oxygenated recycle gas supplied to it. In addition, from 10% to 20% of the total oxidant flow (nearly pure oxygen) to the boiler is injected into the burner flames.

The combustion system on this boiler is un-staged to mitigate furnace corrosion. When firing bituminous coals, the combustion system has a significant impact on the degree of corrosion expected in the furnace. Medium to high sulfur coals can be expected to contribute to FeS deposition/corrosion and to some extent H_2S gas phase corrosion in the presence of a reducing and/or alternating reducing and oxidizing atmosphere. These conditions will exist in the furnace burner zone extending up to and through the OFA port elevation on a staged combustion system. In order to avoid this hazard, an un-staged firing arrangement will be utilized on this boiler. This will eliminate the need for Inconel 622 weld overlay in the furnace. Eliminating staging is a corrosion mitigation strategy. B&W PGG recommends only spot protection with thermal flame spray of any local areas of corrosion should they occur in operation.

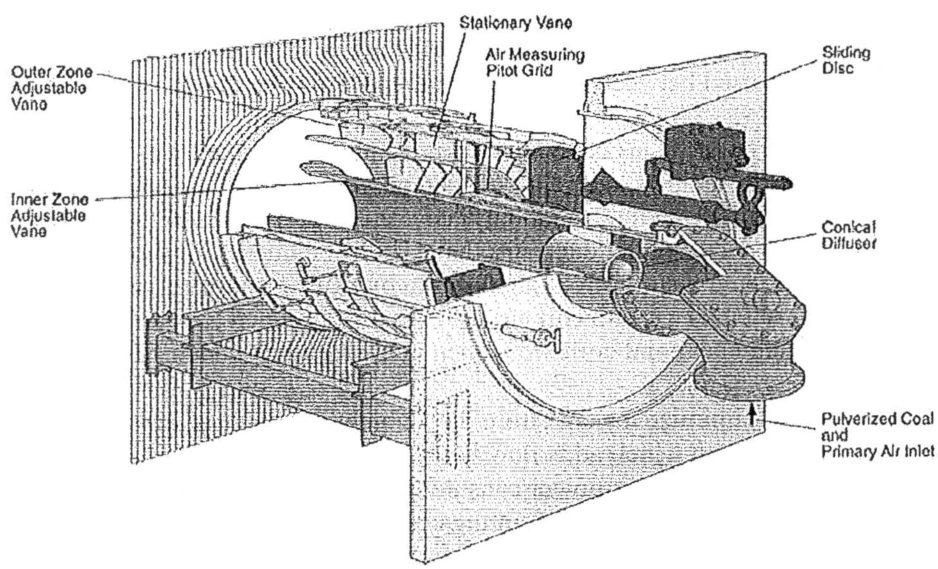

Figure 3-4
HV-XCL Burner

A single retractable #2 oil lighter with air atomization is installed in each burner for startup. Each lighter is capable of approximately 15% of the burner full load heat input (18 lighters at approximately 26.4 GJ/hr [25 MBtu/hr] based on 44,900 kJ/kg [19,300 Btu/lb] HHV and approximately 600 kg/hr [1,300 lb/hr] oil flow). Since this boiler is capable of full load firing with two-thirds of the burners in service (one pulverizer out of service), the total heat input capability with all oil igniters in service is approximately 22.5% of the boiler full load heat input.

Oxidant Injection

The oxidant is injected in three locations: the primary recycle stream after the recycle heater and before the pulverizers, the secondary stream before the recycle heater and thirdly, into the burner flame. In the primary stream oxidant is injected to maintain the O_2 concentration in the recycle gas at slightly less than the O_2 concentration in normal air. This is done to reduce the risk of fire in the pulverizers and coal lines. Capability is provided to inject from 10% to 20% of the total oxidant flow to the boiler directly into the burner flames. The remainder of the oxidant required for combustion is injected into the secondary recycle stream.

Fans and Air Intakes

There are three sets of 2 x 50% centrifugal fans for the oxy-fired boiler process; two primary recycle fans, two secondary recycle fans, and two induced draft fans. The primary recycle fans supply the recycle gas to the pulverizers for coal drying and to transport the pulverized coal from the pulverizers to the burners. They also supply sealing and cooling gas for the pulverizers, coal feeders and other equipment. The primary recycle fans are located between the direct contact cooler/polishing scrubber (DCCPS) outlet and the recycle heater. The secondary recycle fans supply recycle gas to the burner windbox. They are located between the WFGD absorber outlet and the recycle heater. The induced draft fans draw the flue gas leaving the boiler through the pulse jet fabric filter (PJFF) and forces it through the WFGD absorber and then either to the stack or to the DCCPS depending on whether or not the boiler is in carbon-capture mode. The induced draft fans are located between the PJFF and the WFGD absorber.

Both the primary and secondary fans have inlet ducts arranged so that either air or recycle gas can be supplied to them. The ducts have shut-off dampers so that only air is supplied to the fans when the boiler is in the air-firing mode and only recycle gas is supplied to the fans when the boiler is in oxy-firing mode. The inlet ducts also have control dampers for modulating the air and recycle gas flow during the transition from air-firing to oxy-firing and vice-versa. Located at the air inlet to the secondary fan is a steam coil air heater that is designed to protect the recycle heater from cold-end acid dew point corrosion when in the air-firing mode.

The fans are designed to minimize leakage from the ambient into the gas stream because air infiltration introduces nitrogen which adds flow to the gas path and the compression and purification unit (CPU) and increases power consumption. The fans for this project are capable of accommodating an expanded range of operating conditions due to operational uncertainties of the new oxy-fired technology and to allow some flexibility for research and testing. Several options for fan design and operation are considered to determine the most economical design that both covers the range of operating conditions and optimizes the fan performance at the expected normal operating points.

Sootblowers

The locations and quantities of sootblowers suitable for steam blowing are based on Diamond Power recommendations and B&W PGG standards for firing the specified range of Illinois #6 coal. Convection pass sootblowers are installed on one boiler side wall. The convection pass blowers are Diamond Power's IK-700's, the recycle heater blowers are IK-DM's and the furnace will be steam cleaned by IK-4M's which will function the same as Diamond Power's typical furnace IR blowers. Special sealing methods are used to prevent air infiltration into the boiler or flue gas leakage into the building from the sootblower openings.

Bottom and Convection Pass Ash Removal

Bottom Ash

The bottom ash removal system will consist of a transition chute, submerged chain conveyor with water recirculation pumps, sludge pumps and heat exchangers. For the water recirculation pumps, the sludge pumps and heat exchangers, two of each will be supplied, one operating and one installed as a spare. The submerged conveyor will run from the furnace transition chute beneath the furnace hopper to the silo storage. The conveyor will include the maintenance rollout feature. This conveyor will completely clear the transition chute when in the rolled out position allowing for direct access to the boiler throat. An OSHA compliant maintenance access platform and staircase will be provided for inspection and service access to the head section.

A hydraulic conveying system is also provided for pyrites (mill rejects). The pyrites system will transport the pyrites from the pulverizers to the submerged chain conveyor system.

Convection Pass Ash

The economizer hopper ash will be removed from the hoppers via knife-gate valves and discharged onto a dry single strand collecting drag conveyor directly below the economizer. The conveyor will collect the convection pass ash from two hoppers and discharge the ash to a transfer conveyor. The transfer conveyor will transfer the ash from collecting ash conveyor to the submerged bottom ash conveyor.

Steam Coil Air Heater and Gas Reheaters

There are two gas reheaters in this process, the primary gas reheater and the secondary gas reheater. The function of both of these reheaters is to heat the gas leaving the WFGD absorber or the DCCPS, which is at saturation temperature, by 17°C (30°F) to prevent condensation in the downstream flues and fans. The primary gas reheater is located in the DCCPS outlet flue before it splits to the CPU and the primary fans. The gas will leave the DCCPS at a typical temperature (depending on the season) of 21°C (70°F) to 38°C (100°F), and the primary gas reheater will heat this gas by about 17°C (30°F). The primary gas reheater will use a condensate (water) extraction from the turbine as the source for the heating fluid.

The secondary gas reheater is located at the outlet of the WFGD absorber in the flue to the inlet of the secondary fans. The gas will leave the WFGD absorber saturated at a typical temperature between 71°C (160°F) and 82°C (180°F) and the secondary gas reheater will heat this gas by about 17°C (30°F). The secondary gas reheater will also have the function of protecting the recycle heater from acid dew point corrosion at partial boiler loads. When it is serving in this function, the secondary gas reheater may raise the recycle gas temperature by significantly more than 17°C (30°F). The secondary gas reheater will use a steam extraction from the turbine as the source for the heating fluid.

The locations of the steam and condensate extractions are selected to minimize the impact to the overall steam cycle efficiency while still having the capability to accomplish the required amount of gas heating.

The gas reheaters incorporate features to protect against corrosion, minimize the potential for gas side fouling and are designed to accommodate future sootblowers if operational experience indicates that they are needed.

The steam coil air heater (SCAH) was sized to protect the recycle heater from acid dew point corrosion while the boiler is in air firing mode. In addition, these air heaters serve the function of preheating the combustion air for the #2 oil igniters during boiler start-up.

3.4.2 Gas Quality Control Systems (GQCS)

The Gas Quality Control System (GQCS) consists of a Dry Sorbent Injection (DSI) System for the removal of sulfur trioxide (SO_3), a Pulse-Jet Fabric Filter (PJFF) for the removal of particulate matter, a Wet Flue Gas Desulfurization (WFGD) System for the bulk removal of sulfur dioxide (SO_2) and other acid gases and a Direct Contact Cooler Polishing Scrubber (DCCPS) with dedicated cooling tower for flue gas dehumidification and SO_2 polishing. The dehumidification is necessary to provide reasonably dry recycle flue gas to the pulverizers for coal drying and conveying and to reduce the amount of dehumidification required in the CPU. The additional SO_2 polishing of the flue gas in the DCCPS is necessary to minimize corrosion potential in the CPU. The overall GQCS system is depicted in Figure 3-5 below.

From the recycle heater, dry sorbent is injected and all of the flue gas is sent through the PJFF, where more than 99% of the fly ash is removed and approximately 96% of the incoming SO_3 is removed. The flue gas then flows through the ID fans which discharge to the WFGD System where 98% of the SO_2 is absorbed from the flue gas along with HCl and some mercury (Hg). After the WFGD, the saturated flue gas stream is split, with a portion being directed through the secondary gas reheater where it is heated to a margin above the moisture dew point. It then passes through the secondary recycle fans and is recirculated back through the recycle heater to recover energy prior to the boiler windbox. The remainder of the flue gas is sent to the DCCPS for dehumidification as well as polishing of SO_2, SO_3, and acid gases. The saturated flue gas leaving the DCCPS passes through a gas reheater where it is heated to a margin above the moisture dew point and then is split again. A portion is directed to the primary recycle fans to be recirculated back through the recycle heater for heating and to recover energy from the hot flue gas exiting the boiler. The hot primary recycle is then tempered with cooler primary flue gas before entering the pulverizers. The remainder of the flue gas is directed to the CPU for CO_2 purification and compression.

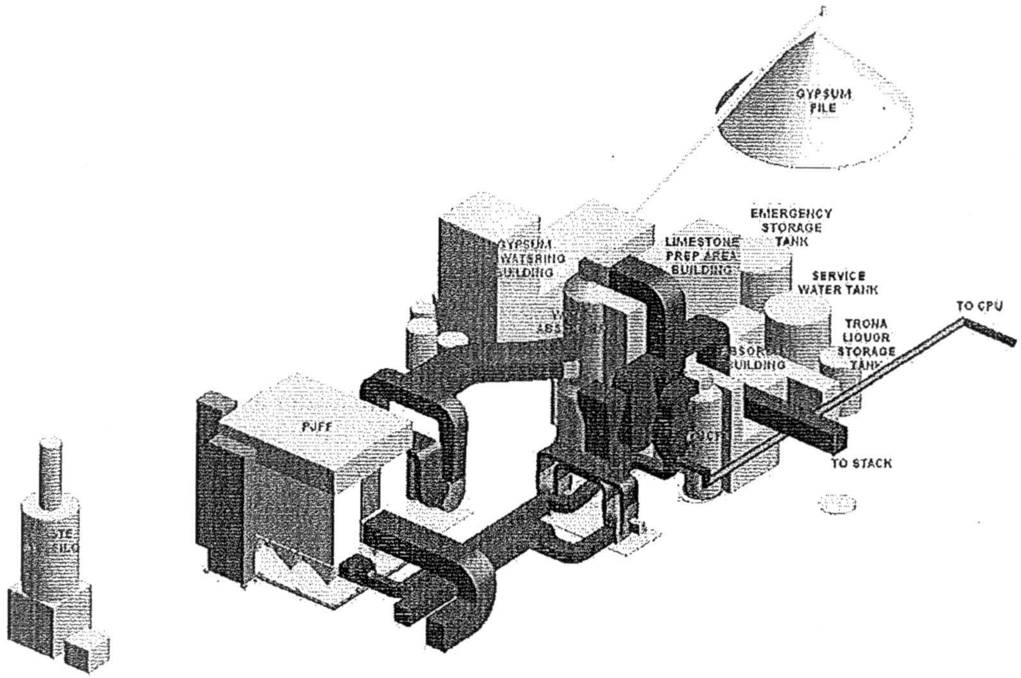

Figure 3-5
GQCS Equipment Arrangement

Pulse Jet Fabric Filter (PJFF) System and Auxiliaries

The single, 100% capacity six (6) compartment PJFF is designed to remove the particulate matter and SO_3/H_2SO_4 reaction products entrained in the flue gas discharged from the recycle heater. Since it is critical to prevent air infiltration into the oxy-firing process, the pulse gas system will use dry CO_2 from the CPU for filter bag cleaning when in the oxy-fired mode. A pulse air compressor and dryers will be used to generate clean, dry compressed air to clean the filter bags when the unit is in the air-fired mode. The fly ash removed by the PJFF will be sent to the waste ash storage silo by the waste ash system.

Pulse Jet Fabric Filter

The PJFF is a self-cleaning dust collector designed to remove particulate matter from the flue gas stream. The PJFF is designed to capture the majority of the fly ash/trona reaction products from the gas prior to it entering the WFGD absorber. The PJFF is an integral component of the system, assisting the trona in the removal of SO_3/H_2SO_4 contained in the flue gas. Figure 3-6 shows a typical hatch-style PJFF, similar to what is proposed for this project.

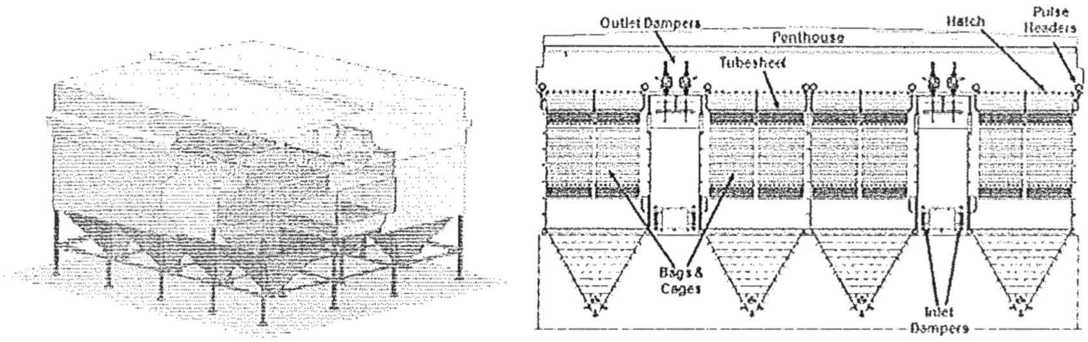

Figure 3-6
Typical Hatch-Style PJFF

The PJFF is located in the flue gas train downstream of the recycle heater and the trona injection point. Flue gas is directed into the individual compartments of the PJFF via the PJFF's inlet manifold. The particulate matter entrained in the flue gas is treated in the PJFF compartments, exits through the common outlet manifold, and then is directed to two (2) 50% capacity Induced Draft (ID) Fans which discharge to the WFGD absorber.

The PJFF consists of six (6) gas-tight filter bag compartments. Each filter bag compartment contains 720 filter bags. Each filter bag is 15.2 cm (6 inch) nominal diameter by 10 meters (32.8 ft) long. The air to cloth ratio with one (1) compartment out of service for maintenance is approximately 75.53 to 1 meters/hr (4.13 to 1 ft/min). The air to cloth ratio with all compartments in service is approximately 62.91 to 1 meters/hr (3.44 to 1 ft/min).

Flue gas laden with particulate matter enters each PJFF compartment below the filter bags, slowing down and changing directions prior to passing through the filter bags from the exterior to the interior of the filter bags. The mechanics of turning and slowing the gas results in some of the particulate matter falling directly into the hopper; the remainder is deposited on the outside surfaces of the filter bags.

Pulse Gas System

To keep pressure losses at an acceptable level, the filter bags are periodically cleaned. During oxy-fired operation, the PJFF filter bags are cleaned using a short pulse of dry compressed gas; air during air firing and CO_2 when oxy firing. The dry CO_2 comes from the CPU and is stored locally in the pulse gas receiver. During air-fired operation, dry compressed air is used to clean the filter bags. In both cases, the compressed gas enters the bag from the top via the blow pipe injection. The air and/or gas pulse expands the filter bag and releases collected dust cake on the outside surface of the filter bag.

The six (6) pulse gas header assemblies, including pulse valves and blow pipes, are designed to accept pulse gas from either the pulse gas system or the pulse air system. Air from the pulse air receiver or CO_2 from the pulse gas receiver is directed to the pulse air headers which are sized to supply a sufficient quantity of gas to each pulse valve with each cleaning pulse. The pulse gas header includes connections for each pulse valve, a drain valve, and a pressure gauge with isolation valve.

Start-up Pulse Air System

For operation in the air-firing mode during startup, clean, dry compressed air is used for filter bag cleaning until the boiler is in the oxy-firing mode and dry CO_2 is available from the CPU. Pulse cleaning air during startup is provided by one (1) pulse air compressor. The compressor has a reduced capacity compared to the amount of compressed CO_2 needed for the oxy-fired mode since only half of the compartments will be in operation.

The pulse air system consists of one (1) 100% capacity air compressor complete with inlet filter and after cooler, one (1) air receiver, two (2) 100% capacity air dryer trains complete with inlet and outlet filters. The compressed air produced by the compressor is discharged to either air dryer train which supplies dried compressed air to the common pulse air receiver.

Waste Ash System

The ash handling system transfers the fly ash collected by the PJFF to the waste ash storage silo for disposal. The free flowing ash from the PJFF is discharged from each of the collection hoppers into the waste ash transport system piping. The ash is conveyed by two (2) 100% capacity PJFF ash transport vacuum blowers. A vacuum-based system is preferred over a pressure-based one primarily due to the decrease in potential for air infiltration into the PJFF hoppers.

The waste ash system consists of a waste ash storage silo complete with bin vent and filter collector, a silo discharge fluidizing air system including two (2) 100% waste ash storage silo fluidizing air blowers (one(1) operating and one (1) spare), one (1) 100% capacity waste ash storage silo fluidizing air heater and one (1) 100% capacity pug mill.

The ash is conveyed pneumatically from the PJFF to the waste ash storage silo via the PJFF ash transport vacuum blowers which pull their vacuum through the silo filter collector. A bin vent is located on the roof of the silo for venting the fluidizing air introduced into the cone of the silo. The silo is sized to hold enough ash to maintain approximately seventy-two (72) hours of system operation when in the oxy-firing mode and burning the coal that produces the maximum ash quantity.

The stored ash in the presence of moisture, if settled, has a tendency to harden. To maintain a fluid state, the silo incorporates a heated fluidizing air system. The air discharged from either fluidizing air blower passes through a common fluidizing air heater before it is distributed to the silo cone by way of flexible hose assemblies. Each hose assembly is equipped with a manual valve and check valve for isolation.

The ash contained in the silo is mixed with either the chloride blowdown stream from the WFGD system or service water in the pug mill to achieve approximately a 20% by weight moisture content in the ash. This eliminates the possibility of dusting when the ash is loaded into trucks or railcars for disposal.

SO_3 Mitigation System and Auxiliaries

The flue gas exiting the recycle heater is at a temperature of approximately 171°C (340°F) at full load when in the oxy-combustion mode. The injection of the dry trona reagent occurs directly downstream of the recycle heater to ensure ample residence time inside the flue work prior to entering the PJFF. It is important to maintain a flue gas temperature below approximately 177°C (350°F) in order to minimize the potential for the formation of sodium bisulfate byproduct which tends to be a sticky salt that can plug injection lances and blind the PJFF bags. Furthermore, the flue gas temperature exiting the recycle heater will be close to the sulfuric acid dew point. When in the oxy-firing mode, the relatively high SO_3 concentration and high humidity results in a relatively high sulfuric acid dew point temperature when compared to a conventional air-fired boiler. To address this concern, a grid of thermocouples for flue gas temperature monitoring is located downstream of the recycle heater. To address the acid condensation potential at the low end of the temperature range, the flue from the recycle heater to the PJFF will be coated with an epoxy-type protective coating. The capture of SO_3 by trona injection will lower the SO_3 concentration in the flue as it makes its way to the PJFF.

Dry Sorbent Injection (DSI) System

The DSI system is installed for the removal of SO_3 and H_2SO_4. The injection lances are located at a suitable distance downstream of the flue gas temperature control water injection grid. This system is designed to use trona as the reagent, at injection rates up to 2 tonnes/hr (2.2 ton/hr). Trona reacts in the flue gas to form a solid compound that is removed in the PJFF. The injection location in the flue work was selected to allow the proper temperature distribution across flues, maximization of residence time and optimal flow distribution.

At optimal temperatures, trona will calcine in the flue to form sodium carbonate. During this calcination process, the trona experiences a "popcorn" effect in which the sorbent particle expands rapidly to form many small pores. The presence of these small pores will increase reactivity of the sorbent with the acid gases. At higher temperatures, sodium bisulfate can form as a secondary reaction product and can rapidly form sticky deposits in the flue and on the PJFF bags which can impede flue gas flow and greatly hinder PJFF performance.

Truck Offload / Silo Filling

The DSI system will be capable of receiving sorbent from self-discharging positive displacement trucks fitted with nominal 100mm (4 inch)diameter discharge connections. A single "truck fill" control panel is included and can be utilized as an information device allowing simple light-based indication of the silo fill status and permissives.

Trona is delivered with a particle size (D50) of 35 microns (1.4 mils). Trona is hydroscopic and tends to form agglomerations when exposed to free moisture. Material properties of trona can be altered above a free moisture content of 0.04%. For this reason, equipment is in place to allow a single PD truck to draw its conveying air from a dehumidification skid. This skid is designed to condition 17 m^3/minute (600 CFM) of ambient air to a dryness level of 1.4 g/kg (10 grains/lb). This is done by first sending the ambient air through a refrigeration unit for cooling and bulk water condensing. The air is then sent through a desiccant wheel dryer where the final dryness levels are achieved. Heated ambient air is used in the dryer to regenerate the desiccant. The dry outlet conveying air is maintained at a temperature below 49°C (120°F) due to the fact that if trona is exposed to temperatures greater than this, pre-calcination may occur which will reduce the reactivity of the product.

Trona Storage Silo

The trona storage silo is of a shop-fabricated, skirted design which reduces on-site construction. The silo is 4.3 m (14 ft) nominal diameter by 23.5 m (77 ft) overall height. This size allows for the storage of 143 tonnes (158 tons) of Trona, or roughly six (6) truckloads, which will allow for three (3) days of Trona storage at the maximum expected injection rate. The area directly beneath the silo will accommodate a single stack-up configuration.

The roof of the storage silo contains a filling target box, vacuum/pressure relief valve, bin vent filter, clean-air vent fan with automatic damper, and continuous handrail around the roof deck. The silo will have three (3) levels (low, high and high-high) of level switches for operational use as well as a continuous level monitor.

The storage silo skirt contains an exhaust fan and a heater for temperature control. During normal oxy-fired operations, dry CO_2 from the pulse gas receiver will be used as the conveying gas. Due to the possibility for conveying gas leakage inside the skirt area, a CO_2 monitor with alarm will also be installed inside the skirt for personnel protection.

Material Feed Stack-Up

Material stored in the silo is maintained in a free-flowing form by the bin activator located at the bottom section of the silo cone. The bin activator need only be activated during the initial start of the injection sequence. The bin activator discharges to a fixed speed rotary valve which discharges sorbent to the downstream material feed equipment.

The stack-up consists of a feeder hopper on load cells and variable speed screw feeder. The weigh bin operates on a loss-in-weight basis, whereby it is filled in a batch operation. The sorbent is delivered at a controlled rate by the screw feeder to a vent hopper and then on to a rotary airlock. Both the feeder hopper and vent hopper include a vent line which discharges back into the silo to capture any vent dust. The fixed speed rotary airlock discharges material into the convey pipe through a pick-up tee.

Conveying Gas and Trona Injection System

During oxy-fired operations, compressed CO_2 from the pulse gas receiver, which is fed from the CPU, will be used for trona conveying. This is necessary to minimize air infiltration into the system. During startup, compressed CO_2 will not be available for sorbent conveying. One (1) 100% trona injection blower will be used for this purpose and any other time that the unit is in the air-fired mode. The blower will come as a separate pre-piped and pre-wired skid including all accessories and instrumentation. The skid will be located outdoors next to the storage silo skirt.

The trona injection blower draws in ambient air through a filter and inlet silencer. A silencer and a relief valve are located on the outlet side of the blower. Upon leaving the blower, the convey air passes through an air-to-air cooler where it is cooled before coming in contact with the trona. This cooling prevents the sorbent from calcining in the convey line before entering the flue. The trona fed into the pneumatic pick-up tee is conveyed through a single pipeline until it reaches the vicinity of the flue. A splitter will be located close to the injection point. As sorbent passes through the splitter, it is divided equally into multiple branch connections, each of which leads to a dedicated injection lance. These injection lances ultimately deliver the sorbent into the flue gas stream to begin the acid gas mitigation reactions. Dispersion nozzles located at the tips of the lances provide necessary distribution of sorbent across the flue.

Flue Gas Desulfurization System and Auxiliaries

The WFGD system has been designed primarily to reduce the emissions of hydrochloric acid (HCl), hydrofluoric acid (HF), and sulfur dioxide (SO_2). The WFGD system is comprised of flue work from PJFF outlet to two (2) 50% capacity induced draft (ID) fans, flue work from the ID fans to the WFGD absorber, flue work from the WFGD absorber to the DCCPS or the stack. See the figure below for a typical WFGD absorber tower with dual trays. Auxiliary systems include a limestone unloading and storage system, limestone slurry preparation, storage and feed system, and a gypsum dewatering system.

Wet Flue Gas Desulfurization (WFGD) Absorber System

The 9.8 m (32 ft) diameter WFGD absorber tower with 11.6 m (38 ft) flared reaction tank is designed for 98% SO_2 removal. The tower is made of alloy A-255 (UNS S32550) above the inlet and has an alloy AL-6XN (UNS N08367) reaction tank. Limestone slurry feed to the absorber is controlled by the inlet and outlet SO_2 loading and the absorber slurry pH. Absorber slurry level, monitored by three (3) hydrostatic level transmitters, is controlled by adding reclaim and makeup water to the absorber. Absorber slurry density, measured in the absorber bleed pump discharge piping by a density meter, is controlled by bleeding absorber slurry to the dewatering system using a batching operation. The reaction tank provides a minimum of 15 hours of solids residence time and is equipped with a drain line and valve for emptying during maintenance periods.

As flue gas passes up through the absorber, it is quenched by the absorber slurry falling from the spray levels and then passes through two stages of perforated absorber trays. The alloy A-255 (UNS S32550) trays are sectioned into compartments by baffles which help to evenly distribute the slurry on top of the trays. Above the trays, the flue gas encounters the absorber spray zone. The absorber spray headers are constructed of abrasion resistant FRP. The absorber slurry is sprayed from silicon carbide spray nozzles.

The absorber module is equipped with two stages of mist eliminators which remove carryover mist by inertial contact. The primary stage captures large particles and the secondary stage captures wash water droplets and finer particles. The two-stage mist eliminator is kept free of slurry deposits by using a water wash system. Two (2) 100% mist eliminator wash water pumps (sized to wash both the WFGD absorber and the DCCPS simultaneously) direct wash water to both the upstream and downstream faces of the first stage and the upstream face of the second stage mist eliminator by an array of spray headers and spray nozzles. The mist eliminators shall be washed sequentially by section to optimize the wash flow rate. The mist eliminator blades, spray nozzles and spray headers shall be constructed of FRP.

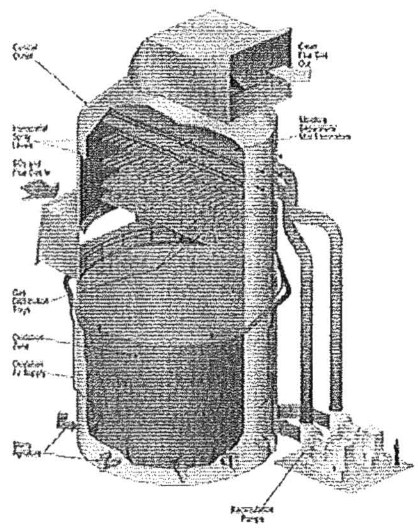

Figure 3-7
Typical B&W WFGD Absorber Tower with Dual-Trays

During oxy-combustion, treated flue gas exiting the WFGD absorber is split, with a portion being directed through the secondary fans. This stream exits the WFGD and is sent to the secondary gas reheater. The reheater raises the gas temperature sufficiently to ensure that the water is in the vapor phase before entering the secondary recycle fans. Following the secondary recycle fans, oxidant is added and the oxygenated secondary recycle then passes through the recycle heater where it is heated and sent to the boiler windbox to participate in combustion in the furnace.

The remainder of the flue gas is sent to the DCCPS for dehumidification and some SO_2 polishing. When in the air-firing mode, the CPU is also not in operation and the primary and secondary fans send ambient air back to the recycle heater instead of recycled flue gas. Because of this, the DCCPS is not in operation and all of the WFGD exit flue gas is sent directly to the stack. During and immediately after transition from air to oxy firing mode the flue gas continues to flow to the stack until it is transitioned to the CPU.

The integral WFGD reaction tank is equipped with four (4) side-entry oxidation air lance type agitators to provide the required mixing and suspension of solids in the tank. The agitator design is such that operation of the absorber system will not be adversely effected if one of the agitators is out of service. All wetted components of the agitators shall be constructed of a corrosion / abrasion resistant alloy suitable for the design level chlorides concentration. The side-entry agitators employ the use of a flush-less mechanical seal which can be replaced while the absorber is on-line.

An in-situ oxidation system forces calcium sulfite ($CaSO_3 \cdot ½H_2O$), formed by the SO_2 removal process, to be oxidized to calcium sulfate ($CaSO_4 \cdot 2H_2O$). The air required to carry out the oxidation reaction is supplied by two (2) 100% capacity oxidation air blowers (one (1) operating and one (1) spare). The air is introduced into the reaction tank via the oxidation air lance agitators. The lance agitators provide dispersion of the oxidation air, as well as agitation of the absorber slurry. Provision is made to keep the oxidation air from infiltrating the flue gas outlet stream. There are seven (7) oxidation air vents equally spaced around the absorber to allow the spent oxidation air to be discharged to the stack. These vents are piped together and routed to the stack flue (start-up flue) at a point downstream of the isolation dampers.

Three (3) 50% capacity Absorber Recirculation (AR) pumps (two (2) operating and one (1) spare) are used to supply the absorber spray headers with slurry from the reaction tank. The AR suction and discharge piping is 1066 mm (42 inch) diameter abrasion resistant FRP and contains a pneumatically actuated butterfly valve both upstream and downstream of the pump for isolation.

Two (2) 100% capacity absorber bleed pumps (one (1) operating and one (1) spare) transfer gypsum slurry from the reaction tank to the primary hydroclone for purposes of absorber slurry density control. The absorber bleed pumps are also capable of transferring slurry from the absorber reaction tank to the emergency storage tank.

One (1) 10.7 m (35 ft) diameter emergency storage tank is sized to hold the contents of the WFGD absorber. During periods of absorber maintenance, the absorber bleed pumps will send the majority of the absorber contents to the emergency storage tank. The final amount will be drained to the absorber area sump and pumped from there to the emergency storage tank. One (1) 100% capacity emergency storage tank transfer pump returns the absorber contents to the WFGD once maintenance is complete. The emergency storage tank can also be drained to the absorber area sump and returned to the WFGD by the absorber area sump pumps.

Limestone Unloading and Storage System

Powdered limestone (PL) is delivered to the plant site via trucks, equipped with onboard positive displacement (PD) blowers, to either of two (2) PL storage silos. Each silo is equipped with a dedicated 100% capacity PL storage silo rotary airlock feeder. Fluidizing air is used to ensure the continuous flow of limestone from the bottom of the silo through the rotary airlock feeder. Each rotary airlock feeder delivers powdered limestone to a dedicated limestone slurry preparation and storage system.

Two (2) 6.9 m (22.5 ft) diameter PL storage silos provide a total of four (4) days of onsite storage when firing the design coal at the maximum continuous boiler rating. A dust filter is supplied on the roof of the silo for filtering and venting the transport air and displaced silo air during filling.

To maintain a fluid state, the PL storage silo incorporates a fluidizing air system. Three (3) 50% capacity PL storage silo fluidizing air blowers (two (2) operating and one (1) spare) provide fluidizing air to the fluidizing air system supply header and distributed to the silo cone by way of flexible hose assemblies. Each hose assembly is equipped with a manual isolation valve and check valve. Each hopper discharge is equipped with a dedicated 100% capacity rotary airlock feeder.

Limestone Slurry Preparation, Storage and Feed System

The limestone slurry preparation, storage and feed system consists of two (2) 100% capacity limestone slurry preparation and storage trains. Each train consists of a PL sluice bowl and a limestone slurry storage tank with agitator. The limestone slurry feed system consists of two (2) 100% capacity limestone slurry feed pumps (one (1) operating and one (1) spare) and a 100% capacity limestone slurry feed loop.

The powdered limestone that is discharged from each PL storage silo is combined with service water or WFGD reclaim water in a dedicated sluice bowl to a suspended solids concentration of approximately 28% by weight. The limestone slurry discharged from each sluice bowl flows by gravity into its dedicated limestone slurry storage tank. Additional water can be added through the non-operating sluice bowl if needed to correct the slurry density.

Two (2) 6.9 m (22.5 ft) diameter limestone slurry storage tanks provide a total of 16 hours of slurry storage at the maximum usage rate. The liquid slurry level in these tanks varies from the low level setpoint to the high level setpoint. The management of limestone slurry reserves within the system will enable the process to buffer temporary swings in boiler load and fuel sulfur content.

Two (2) 100% capacity limestone slurry feed pumps (one (1) operating and one (1) spare) draw suction from a crosstie that is common to both the limestone slurry storage tanks. Each of the limestone slurry feed pumps maintains a continuous flow of limestone slurry through the common limestone slurry feed loop. Only a fraction of the slurry entering the feed loop is delivered to the WFGD absorber which is necessary to maintain limestone pipe velocities within the proper range. The remaining slurry entering the feed loop is returned to either of the limestone slurry storage tanks. The actual flow of limestone slurry to the WFGD absorber is dependent upon the SO_2 concentration at the absorber outlet and absorber recirculation slurry pH.

Gypsum Dewatering System

Gypsum slurry from the absorber is fed to the primary hydroclones by two (2) 100% capacity absorber bleed pumps (one (1) operating and one (1) spare). The purpose of the primary hydroclones is to concentrate the solids of the gypsum slurry stream for secondary dewatering. The secondary hydroclones further decrease the solids content in the final chloride blowdown stream. Each hydroclone battery consists of multiple cyclones (with 20% minimum spare units) which operate at a constant flow rate. Flow is added involutedly to produce a swirling motion inside the hydroclone. This swirling motion produces a centrifugal force and affects solids separation.

Primary hydroclone overflow is sent to a standpipe which provides positive suction pressure for the two (2) 100% capacity secondary hydroclone feed pumps (one (1) operating and one (1) spare). These pumps draw off a portion of the slurry and deliver it to the secondary hydroclone. The remainder of the slurry that continuously overflows from this standpipe is sent by gravity to either of the reclaim water tanks and eventually is returned to the absorber reaction tank. The underflow from the primary hydroclone is gravity fed to either of the filter feed tanks for further dewatering.

Secondary hydroclone underflow is gravity fed to either of the reclaim water tanks while the overflow flows to the chloride blowdown tank. Two (2) 100% capacity chloride blowdown pumps (one (1) operating and one (1) spare) send blowdown to the waste ash pug mill for waste ash conditioning. This blowdown stream is necessary to limit build-up of chlorides and fine particulate matter in the absorber system.

Two (2) 4.9 m (16 ft) diameter filter feed tanks provide a total of 16 hours of storage capacity based on the primary hydroclone underflow production at the maximum rate. Two (2) 100% capacity filter feed pumps (one (1) operating and one (1) spare) are used to transfer the slurry via the filter feed loop to the vacuum drum filters. Two (2) 100% capacity rotary drum vacuum filters (one (1) operating and one (1) spare) are used to dewater the gypsum to approximately 80% by weight suspended solids. The gypsum cake is then transported from the drum filters by the gypsum conveyor to the gypsum storage pile for disposal.

The drum filter filtrate pumps (one per filter) direct the filtrate from the drum filters to either of the reclaim water tanks. Two (2) 4 m (13 ft) diameter reclaim water tanks provide a total of 16 hours of storage capacity based on the filtrate production at the maximum rate. Two (2) 100% capacity reclaim water pumps (one (1) operating and one (1) spare) recycle the filtrate back to the WFGD absorber for level control. Make-up water to the reclaim water tanks consists of either fresh service water or the DCCPS wet cooling tower blow down.

Flue Gas Dehumidification System

The dehumidification system is comprised of a DCCPS and a dedicated wet cooling tower (by URS). Two (2) 100% capacity DCCPS blowdown pumps (one (1) operating and one (1) spare) send reaction tank liquor to the cooling tower. Two (2) 100% capacity cooling tower recirculation pumps (one (1) operating and one (1) spare) (by URS) return cooled water from the cooling tower back to the DCCPS spray headers. Trona liquor reagent is added to the cooling water supply stream by the trona liquor feed pumps.

Direct Contact Cooler Polishing Scrubber (DCCPS)

After removal of most of the SO_2 in the WFGD absorber, the saturated flue gas is sent to the DCCPS. It is in this vessel that the flue gas is cooled below the adiabatic saturation temperature (to about 24 °C [75 °F] during normal conditions) to condense water, and the flue gas SO_2 concentration is further reduced to about 1 ppm (dry). The 6.3 m (20.75 ft) diameter DCCPS vessel is constructed of 316L stainless steel. The bottom of the conical reaction tank is equipped with a drain line and valve to aid in the complete emptying of the vessel during maintenance periods. The primary means of reaction tank draining is by the DCCPS blowdown pumps.

The gas entering the DCCPS passes through two (2) standard spray levels which are supplied with cool liquor from the cooling tower recirculation pumps. The spray headers are constructed of FRP and the supports are constructed of stainless steel. The absorber liquor is sprayed from silicon carbide spray nozzles.

Above the spray headers, the scrubber is equipped with two (2) stages of FRP mist eliminators which remove carryover mist by inertial contact. The primary stage is for bulk entrainment (large particle capture) while the secondary stage acts as a polishing stage (wash water droplet and finer particle capture). This two-stage mist eliminator is kept free of deposits by using an integral wash water system. Service water is directed to both the upstream and downstream faces of the first stage and the upstream face of the second stage mist eliminator by an array of spray headers and spray nozzles. The mist eliminators shall be washed sequentially by section to optimize the wash flow rate. The mist eliminator blades, spray nozzles and spray headers shall be constructed of FRP. By having the DCCPS in series with the WFGD, the gypsum carryover is greatly reduced due to effectively four stages of mist eliminators (two stages per vessel).

The dehumidified and polished flue gas exits the DCCPS and is sent to the primary gas reheater. The reheater raises the gas temperature sufficiently to ensure that the water is in the vapor phase before entering the CPU and primary fans, which are located downstream. Downstream of the reheater, a portion of the flue gas is sent through the primary fans back to the recycle heater, while the remaining flue gas is sent to the CPU for CO_2 purification and compression.

Trona Unloading and Solution Preparation, Storage and Feed System

Sodium sesquicarbonate (trona) is used in the DCCPS to reduce remaining pollutants such as SO_2 and other acid gases (HCl, HF, H_2SO_4) in the flue gas to desired levels at the CPU inlet. The trona reacts primarily with the SO_2, producing sodium sulfate and sodium bisulfate as reaction products. Those reaction products will steadily increase in concentration over time and therefore a blow down stream is required to maintain an allowable steady state concentration of the dissolved solids in the DCCPS circulating liquor. Eventually, the dissolved solids captured in the DCCPS leave the process via the liquid phase of the gypsum cake and via the chloride blow down stream that is used for flyash wetting.

Dry trona is delivered to the site via self-discharging positive displacement trucks to either of two (2) 100% capacity trona filter receivers. Each filter receiver is equipped with a collection hopper, a 100% capacity rotary feeder and a wetting box. Clean dry air is piped to the hopper to ensure the free flow of reagent into the downstream equipment.

Both 100% capacity filter receiver/rotary feeder/wetting box assemblies are mounted on top of a common 6.9 m (22.5 ft) diameter trona liquor storage tank. The water added in the wetting box is adequate to make a 12.5% by weight solution of trona liquor in the storage tank. The storage tank provides sufficient storage capacity for 1.5 truckloads, and is constructed of lined carbon steel. The tank is equipped with a dual impellor agitator to ensure the trona completely dissolves and two (2) immersion heaters to maintain a liquor temperature of 15.6 °C (60°F) or higher (which prevents liquor crystallization).

The trona liquor is added to the system by two (2) 100% capacity trona liquor feed pumps (one (1) operating and one (1) spare). The pumps tie into a common discharge loop which supplies reagent to the main cooling tower recirculation line. Since the reagent required during normal oxy-fired operation is minimal, the remainder of the feed liquor is recycled back to the storage tank.

3.5 *Air Separation Unit (ASU)*

The ALPC ASU will be an integrated component of the Oxy-Combustion Power Plant Facility. This ASU will supply oxygen for the Boiler Island, and the process is simply illustrated in Figure 3-8.

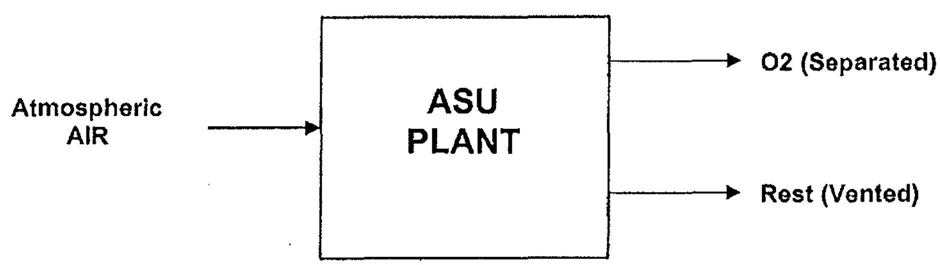

Figure 3-8
Basic Air Separation Process

ALPC has extensive experience with the air separation process, with over 3,500 plants built not only for 3rd party clients but also for our own operating facilities at over 550 locations around the world. Consequently ALPC can reference, and thus benefit from, a large amount of industrial operations data for the engineering and construction activities.

ALPC incorporates feedback from its operating facilities into new designs to continually improve and maintain its position as the world leader in gases for industry, health and the environment.

Being both a supplier and an operator of plants, ALPC selects the most suitable design for each project taking into account:

- Type and characteristics of product utilization
- Compression system
- Automation needs
- Availability of utilities
- Plant layout
- Overall power efficiency
- Safety
- Operability

3.6 *Compression and Purification Unit (CPU)*

The ALPC CPU will be an integrated component of the Oxy-Combustion Power Plant Facility. Its function is to take low pressure (~1atm) Flue Gas from the GQCS and to compress (to ~145 barg [2,100 psig]) and purify (expected purity is 99.7% mass) it for subsequent transport and storage.

The CPU process is simply illustrated in Figure 3-9.

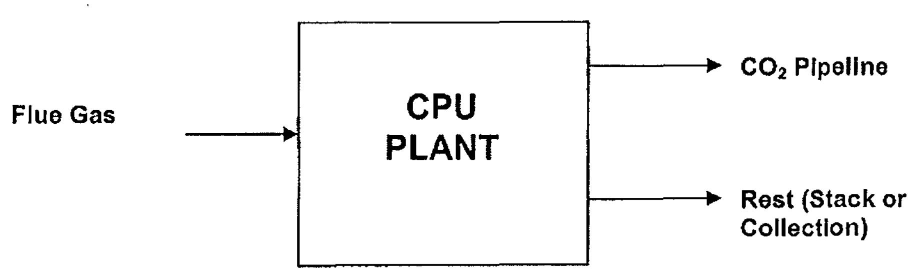

Figure 3-9
Basic Compression Purification Process

The FutureGen 2.0 CPU design benefits from ALPC's extensive development work already carried out in the Oxy-Combustion field. Highlights of this activity include the pilot plants at Lacq (France) and Callide (Australia).

CO_2 Transfer to Alliance Pipeline

Liquid CO_2 at the conditions specified in Table 3-4 will be delivered to the Alliance at an underground pipeline interface point (300 mm [12"] nominal) located near the east boundary of the Meredosia Plant. An isolation valve will be installed near the CPU battery limit (downstream of the CPU discharge interface point) to initiate or shutoff flow to the pipeline as required. Control of the CO_2 isolation valve will be managed by the Meredosia Plant, but operation of the CPU and the isolation valve must be a coordinated effort with the Alliance.

CO_2 flow, pressure, temperature, and quality will be monitored at the CPU discharge upstream of the pipeline isolation valve. Additional monitoring closer to the Alliance pipeline interface point, along with potential automated control of the isolation valve, will be evaluated during Phase 2 as design details are developed. Remote monitoring capability may also be implemented to allow the Alliance to directly monitor CO_2 conditions at the CPU discharge.

During operation, if CO_2 conditions do not meet the required specifications per Table 3-4, Ameren will notify the Alliance and a decision made as to whether the process upset can be accommodated or whether flow to the pipeline should be stopped. No specific allowance for out-of-spec CO_2 is provided for in the CO_2 offtake agreement, but minor upsets will likely be able to be accommodated by the CO_2 storage facility, since they will be diluted by the CO_2 inventory already in storage.

During CPU startup, shutdown, or other operating condition when the pipeline isolation valve is shut and no CO_2 delivery to the pipeline is occurring, CO_2 must be discharged elsewhere until pipeline deliveries can resume. While the startup stack and normal CPU vent will accommodate many such conditions, additional backup discharge points may be required to facilitate practical CPU operation during upsets. Details regarding such backup discharge points will be finalized in Phase 2, but may include on-site CO_2 storage or additional CO_2 venting capability downstream of the CPU battery limit.

Additional monitoring and reporting requirements will be developed and finalized during Phase 2.

3.7 *Steam Cycle and Balance of Plant Systems*

In general, the design and configuration of the steam turbine power cycle is typical of any similar coal-fired Rankine cycle power plant designed in the late 1960s. As such, the following system descriptions provide only a general overview of each major system. Typical system design details are not discussed at length unless unique to the design of the plant.

A detailed assessment of the existing plant equipment was completed by URS during Phase 1 to determine which existing components needed replacement or refurbishment to support the repowered oxy-combustion configuration of Unit 4. This section generally identifies existing plant components that will be reused vs. those components that will be replaced. Additional details regarding equipment reuse, refurbishment, or replacement are addressed in separate plant assessment reports developed by URS.

3.7.1 Steam Systems

Main and Reheat Steam

The main steam system transports high pressure and temperature steam from the steam generator secondary superheater outlet header to the inlet of the main stop valves of the HP turbine. The system also directs steam to the steam turbine seal system at low loads when there is insufficient steam supply from the normal extraction steam (IP-LP turbine crossover) supply.

The design pressure of the main steam system is equal to the lowest steam generator superheater safety valve set pressure. The maximum operating pressure is 175.9 barg (2,550 psig). The design temperature corresponds to the steam generator MCR superheater outlet temperature of 542.8°C (1,009°F) plus a 5.6°C (10°F) margin added to account for the accuracy of the temperature control. The piping system is designed in accordance with ASME B&PV Code Section I and ASME B31.1 rules for boiler external piping. The material for the main steam piping is a seamless ferritic alloy steel, SA 335 Grade P91, which provides superior stress and creep properties.

The cold reheat steam system transports steam from the outlets of the HP steam turbine to the steam generator reheater inlet headers. A portion of the cold reheat flow is also directed to the steam side of the No. 4-6 high pressure feedwater heater. The system is designed in accordance with the requirements of ASME/ANSI B31.1 rules for non-boiler external piping. Design pressure of the system is equal to the lowest set pressure for the safety valves on the reheater inlet. The maximum operating pressure is 39.9 bara (578.1 psia). Design temperature is equal to the HP turbine outlet temperature at VWO conditions plus a 13.9°C (25°F) margin. The material for the cold reheat piping will be ASTM A335 Grade P22.

The hot reheat steam system conveys the heated steam from the steam generator reheater outlet headers to the inlet of the reheat stop valves of the intermediate pressure turbine. The system is designed in accordance with the requirements of ASME/ANSI B31.1 rules for non-boiler external piping. The design pressure of the system is equal to the design pressure of the reheater. The maximum operating pressure is 37.8 bara (548 psia). The design temperature is equal to the temperature at the reheater outlet at VWO plus a 8.3°C (15°F) margin. The material for the hot reheat piping is seamless ferritic alloy steel, SA 335 Grade P91, which provides superior stress and creep properties.

Other system design criteria include:

- Piping sized for turbine generator VWO load case conditions.

- Maximum velocity at VWO conditions not to exceed 102 m/sec (20,000 ft/min) in main steam and hot reheat steam headers and 76 m/sec (15,000 ft/min) in cold reheat headers. Lower velocities may be required by the steam turbine vendor at the inlet to the steam turbine.

- Steam line drains supplied as required to meet the requirements of ASME TDP-1 "Recommended Practices for the Prevention of Water Damage to the Steam Turbines Used for Electric Power Generation."

Extraction and Low Pressure Steam

The extraction and low pressure steam system transports steam from extraction steam points on the steam turbine and the cold reheat line to the closed feedwater heaters, the deaerator, the Secondary Recycle Gas Heater, oxygen heaters and the ASU and CPU "islands" for process heating.

Six (6) feedwater heaters are included in the steam power cycle design to heat condensate and feedwater from the condenser temperature to the design boiler feedwater inlet temperature of 247°C (477 °F) at the performance condition.

The system is designed to meet the recommendations of ASME TDP-1 "Recommended Practices for the Prevention of Water Damage to the Steam Turbines Used for Electric Power Generation." In accordance with TDP-1 each extraction line has a motor operated isolation valve and power assisted non-return valve.

System components with design temperatures less than 399 °C (750 °F) are generally fabricated from carbon steel (ASTM A106 Grade B). Components with design temperature above 399 °C (750 °F) are fabricated in accordance with SA 335 Grade P91 or from 2 ¼ % Cr 1% Mo alloy steel material (ASTM A335 Grade P22).

The system is also designed in accordance with the following criteria:

- Piping sized for turbine generator VWO load case conditions and such that pressure of 165.5 barg (2,400 psig) will be delivered to the turbine steam chest.

- Maximum velocity at VWO conditions will not exceed 76 m/sec (15,000 ft/min) in extraction steam piping, except for extractions under vacuum, where velocity may be up to 102 m/sec (20,000 ft/min).

- Extraction steam piping design pressures are 115% of the turbine extraction pressure as shown on the VWO steam cycle heat balance. Design temperatures are determined based on the established design pressure and the extraction steam entropy as determined from the steam cycle heat balance.

Auxiliary Steam

The auxiliary steam system takes steam from the main steam system, conditions it through a pressure reducing and desuperheating station, and provides low pressure and temperature steam for the following uses:

- Deaerator pegging during start up and low load conditions when extraction steam is not available at sufficient pressure.
- Main steam turbine sealing steam during start up and low load conditions when the normal source of steam from the turbine HP gland leakoff is not sufficient.
- Chemical cleaning equipment and water treatment equipment
- Pulverizer inerting in the event of a pulverizer fire
- Process heating in the Boiler, GQCS, ASU and CPU "islands"
- Space heating in the existing Main Plant and for Unit 3 cross-tie
- Fuel oil heating at the barge unloading terminal, as required

An auxiliary boiler is included for startup.

3.7.2 Steam Turbine Generator

Steam Turbine Generator Design

The existing steam turbine-generator consists of one (1) Westinghouse, Tandem Compound, Double Flow Reheat turbine and one (1) hydrogen-cooled generator. The LP sections are downward exhaust.

The turbine-generator is rated at 194,175 kW gross with steam inlet conditions of 157.7 barg (2,286 psig) and 538 °C (1,000 °F), reheat to 538 °C (1,000 °F). The rated speed is 3,600 rpm.

Main steam from the boiler flows through the turbine's main stop valves and control (governing) valves and enters the HP turbine. It expands through the HP section and exhausts as cold reheat to the boiler. Hot reheat steam from the boiler flows through the turbine's reheat stop valves and intercept valves and enters the IP section. It expands through the IP and then enters the crossover piping, which transports the steam to the LP elements. LP steam is divided between the two LP elements and exhausts into the condenser.

The steam turbine was originally designed for fixed pressure, partial-arc operation. However, to optimize performance for the oxy-combustion plant, turbine operation will be modified to a hybrid sliding pressure operating mode.

The turbine provides for six (6) feedwater heater extraction points, as indicated in the steam cycle heat balance diagram, with full load extraction pressures. Final feedwater temperature at full load is 247 °C (477 °F).

The electrical generator is rated at 233 MVA, 60 Hz with a power factor of 0.90. The generator is a hydrogen-cooled design.

Steam Turbine Auxiliaries

Major turbine auxiliary systems and components include the following.

Gland Seal System

The gland seal system serves to prevent steam leakage through shaft penetrations at the ends of each turbine element and from the valve stems. It also prevents air in-leakage into the condenser through LP turbine shaft penetrations. The system is partially integrated with the BOP auxiliary steam system and consists of piping, pressure regulating valves, and a gland steam condenser with 2x100% capacity motor-driven exhausters.

Lubricating Oil System

Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system. The system includes piping, oil reservoir, oil heaters, one (1) main and one (1) back up full-capacity AC oil pumps, one (1) emergency DC oil pump, 2x100% water-cooled lube oil coolers, a vapor extractor, oil purifier and duplex oil filter.

Turbine Governor System, Hydraulic Oil System, and Trip System

The turbine governor system controls turbine speed, load and throttle pressure over the full operational load range. Turbine start-up, shut-down, and load change are directed by the governor system.

The turbine stop valves, control valves, reheat stop valves, and intercept valves are positioned by the control system that is part of the governor system. The hydraulic oil system includes piping, fluid reservoir, two (2) independent, parallel, full-capacity AC fluid pumps, 2x100% water-cooled hydraulic oil fluid coolers and duplex fluid filter.

Generator Gas Cooling and CO_2 Purge Systems

The existing generator gas cooling system cools the generator utilizing hydrogen gas. The system includes a hydrogen manifold with integral pressure regulation, hydrogen purity instrumentation, dual tower hydrogen dryer and hydrogen-to-water coolers. The CO_2 purge system includes a CO_2 manifold with integral pressure regulation, along with a CO_2 vaporizer heater and purge control valves.

Hydrogen Seal Oil System

The existing hydrogen seal oil system provides containment of the hydrogen gas within the generator by maintaining the seal oil pressure at a small differential above the gas pressure. The system includes seal oil pumps and gas coolers.

Generator Excitation System

The existing excitation system provides the power to maintain the generator voltage.

3.7.3 Condensate and Feedwater

The existing feedwater and condensate systems of the thermal cycle consist of six feedwater heaters and two pressure levels of pumping. The feedwater system comprises the equipment and piping from the deaerator storage tank outlet to the boiler economizer inlet. The condensate system comprises the equipment and piping from the turbine condenser to and including the existing, relocated, deaerator and storage tank. The condensate/feedwater system process flow diagrams are included.

The condensate and feedwater system is also integrated with the GQCS, ASU, and CPU islands to provide heating and cooling requirements for those islands as required.

Feedwater System

The deaerator storage tank provides a suction reservoir for the feedwater pumps, which discharge through two existing high pressure shell and tube feedwater heaters (heaters no. 5 and 6). The high pressure feedwater heaters perform the final two stages of feedwater heating, with a nominal final feedwater temperature of 247°C (477°F). Heater no. 5 receives steam from IP turbine exhaust and heater no. 6 is fed from cold reheat (HP exhaust). High pressure heater drains cascade through successive lower pressure heaters and normally directed to the deaerator.

The existing main feedwater pumps are motor driven using a hydraulic coupling to vary the flow. This arrangement allows efficient variable speed drive for these large pumps.

The feedwater heaters are capable of operating at any load condition and are capable of accepting increased extraction steam flow rates resulting from removing one or more heaters from service or from cascading the heater drains to the condenser.

Condensate System

Steam is condensed from the main turbine in an existing two-pass, shell and tube type steam surface condenser with divided water boxes, admiralty and stainless steel tubes and Muntz-metal tube sheets. Vacuum pumps are used to create and maintain condenser vacuum. System make-up will be vacuum drained from a new, 380 m^3 (100,000 gallon), lined-steel, condensate storage tank into the hotwell.

Two existing, 50% capacity, can-type vertical condensate pumps pump water from the condenser hotwell through an ion-exchange polishing system, a gland steam condenser, three existing conventional shell and tube feedwater heaters (heaters no. 1 through 3), to a direct contact deaerating feedwater heater (heater no. 4). Drains from heaters no. 2 and 3 are cascaded through heater no. 1 to the condenser.

The condensate pumps are designed to handle the condensate generated at the VWO rating. The pump cans are set to a depth that provides adequate NPSH at the suction flange at all conditions, including one pump runout. A common minimum flow recirculation system is designed to provide the required minimum flow for the pumps and/or the gland steam condenser. The pump total head requirement is 283 m (930 feet) TDH.

The low pressure heater shell side design pressure and temperature are based on the associated extraction steam line design pressure. The tube side design pressure is equal to the design pressure of the condensate piping, with the tube side design temperature based on saturation temperature for the shell side design pressure.

To maintain water chemistry within the limits required for the subcritical boiler design, an all-volatile treatment (AVT) chemistry program is used, employing ammonia for pH control and hydrazine for oxygen scavenging. Additionally, full condensate flow from the hotwell is polished, as required, to assure water quality is maintained.

3.7.4 Heat Rejection (Cooling Water) Systems

Main Circulating Water

The main circulating water system provides a continuous supply of cooling water for heat rejection from the main steam condenser. The circulating water system is designed to the following parameters:

- A condenser steam-side pressure of approximately 63.5 mm (2.5 in) HgA under average annual operating conditions (94.0 mm [3.7 in] HgA under summer design conditions).
- Cooling tower designed at summer conditions with 45.6°C (114°F) inlet water temperature, 33.3°C (92°F) outlet water temperature with an ambient 24.4°C (76°F) wet bulb temperature.

The system is a wet recirculating design that includes the following major equipment:

- One (1) steam surface condenser
- One (1) four-cell mechanical draft, crossflow cooling tower
- Two (2) x 50% capacity main circulating water pumps
- Two (2) x 100% capacity condenser vacuum pump skids

System main circulating water piping is arranged in a single common supply and single common return header configuration, as generally depicted on the plot plan, with individual risers to each side of the cooling tower water deck and individual branches to the split condenser waterboxes. Underground existing main circulating water piping is coated and wrapped steel material.

Water chemistry within the circulating water system is maintained through chemical injection and system blowdown rates.

Condenser

An existing two-pass divided waterbox steam surface deaerating condenser is provided to condense exhaust steam from the LP turbine exhausts. The unit is constructed with 25.4 mm (1 inch) OD, BWG 18 Admiralty tubes and 25.4 mm (1 inch) OD BWG 20 Type 304 stainless steel tubes, primarily for air removal. Tube sheets are Muntz metal. Performance under normal base load operating conditions is reflected on the steam cycle heat balance.

Cooling Tower

The main cooling tower rejects cycle heat from the main condenser and closed cooling water system to atmosphere. The existing main cooling tower will be replaced with a new tower constructed on the existing basin. The new tower is a crossflow, induced-draft design comprising 4 individual cells, each equipped with a single speed 149 kW (200 hp) electric motor-driven fan. Tower design conditions are as stated above. Tower performance under normal base load operating conditions is reflected on the steam cycle heat balance and on the water balance.

The tower is built over a common concrete cold water basin, with a pump pit provided at one end. The tower structure is of fiberglass reinforced plastic (FRP) construction. The pump pit is a reinforced concrete structure, equipped with trash racks.

Main Circulating Water Pumps

The circulating water pumps are vertical motor-driven constant speed, mixed flow design pumps. The pumps are self lubricated and are provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge is provided with a motor operated butterfly valve and expansion joint. The discharges from each pump are combined into one common supply header.

Both pumps are required to operate to achieve maximum plant performance as reflected in the steam cycle heat balance. Should one pump be out of service, plant operation can be continued with single pump operation. Limitations on steam turbine load during single pump operation are dependent on ambient conditions, but are partially mitigated due to the runout characteristics of a single operating pump.

Condenser Vacuum Pump Skids

Each existing condenser vacuum pump skid contains a single full capacity rotary type condenser vacuum pump and associated separator tank, seal water pump, and seal water cooler. During normal base load operation, a single operating skid will maintain condenser vacuum at the design point. During startup, both skids can be operated in parallel to shorten the time required to pull initial condenser vacuum.

ASU/CPU Circulating Water

ASU/CPU Cooling Tower

The cooling tower rejects cycle heat from the ASU and CPU "island" closed cooling water systems to atmosphere. The tower is built over a common concrete cold water basin, with a pump pit and pump enclosures provided on one side. The pump enclosure houses the ASU/CPU circulating water pumps. The tower structure is FRP. The pump pit is a reinforced concrete structure consisting of separate chambers for each pump, each equipped with bar screen trash racks.

Water chemistry within the ASU/CPU circulating water system is maintained through chemical injection and system blowdown rates.

ASU/CPU Circulating Water Pumps

The ASU/CPU circulating water pumps are vertical motor-driven constant speed, mixed flow design pumps. The pumps are self lubricated and are provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge will be provided with a motor operated butterfly valve and expansion joint. The discharges from each pump are combined into one common supply header feeding two distinct piping loops.

Both pumps are required to operate to achieve maximum plant performance as reflected in the steam cycle heat balance. Should one pump be out of service, plant operation can continue with single pump service, but at a curtailed level.

DCCPS Circulating Water

DCCPS Cooling Tower

The cooling tower rejects cycle heat from the DCCPS closed cooling water system to atmosphere. The tower is a counterflow, induced draft design comprising 2 individual cells, each equipped with a single speed 186 kW (250 hp) electric motor-driven fan. Tower design conditions are 48.9°C (120°F) inlet water temperature, 32.2°C (90°F) outlet water temperature with an ambient 24.4°C (76°F) wet bulb temperature. Because of the effects of high inlet water temperature on tower material, a significant portion of the cooled water from the basin is mixed with the inlet water. Net tower performance under normal base load operating conditions is reflected in the Project Design Basis Document and on the water balance.

The tower is built over a common concrete cold water basin, with a pump pit and pump enclosures provided at one end. The pump enclosure houses the DCCPS circulating water pumps. The tower structure is FRP. The pump pit is a reinforced concrete structure consisting of separate chambers for each pump, each equipped with bar screen trash racks.

Water chemistry within the DCCPS circulating water system is primarily a function of the GQCS/WFGD operating conditions, but can be controlled when necessary through additional chemical injection and blowdown.

DCCPS Circulating Water Pumps

The DCCPS circulating water pumps are vertical motor-driven constant speed, mixed flow design pumps. The pumps are self lubricated and are provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge will be provided with a motor operated butterfly valve and expansion joint. The discharges from each pump are combined into one common supply header that feeds the DCCPS spray headers. DCCPS liquor is returned by the DCCPS Blowdown Pumps (see B&W PGG description) to the DCCPS Cooling Tower.

Both pumps are required to operate to achieve maximum plant performance as reflected in the steam cycle heat balance. Should one pump be out of service, plant operation can be continued with single pump operation. Limitations on DCCPS effective operation (also limiting steam turbine load) during single pump operation are dependent on ambient conditions, but are partially mitigated due to the runout characteristics of a single operating pump.

Closed Cooling Water

The existing closed cooling water (CCW) System provides condensate quality cooling water to various small duty heat exchangers throughout the plant, thereby acting as a heat sink for those components. Heat from the CCW System is rejected to the Service Water System.

The CCW system serves the following major equipment:

- Bearing cooling on the Motor-driven Boiler Feed Pumps
- Existing air compressor after coolers and intercoolers
- Existing condensate pump motor bearing coolers
- Electro-hydraulic oil coolers
- Sample coolers

The CCW System consists of:

- One shell and tube, two-pass heat exchanger sized to cool 56.8 m^3/hr (250 gpm) of water from 51.7°C (125°F) to 40.6°C (105°F)
- Two 56.8 m^3/hr (250 gpm) horizontal centrifugal pumps, one operating and one standby
- One Closed Cooling Water Storage Tank, 5.7 m^3 (1,500 gallons)

The CCW Storage Tank accommodates system volume variations due to changes in water temperature and ensures adequate suction head is available at the CCW pumps during all operating conditions.

Service Water Cooling

The existing service water cooling system provides filtered river water to various equipment heat exchangers throughout the plant via a once-thru arrangement, thereby acting as a heat sink for those components.

The service water cooling system serves the following existing and new major equipment:

- Service water strainer backwash system
- Main steam turbine oil coolers
- Hydraulic coupling oil coolers for motor-driven boiler feed pumps
- Hydrogen seal oil coolers, air and hydrogen sides
- Generator hydrogen coolers
- Generator exciter coolers
- Vacuum pumps heat exchangers
- CCW heat exchanger
- New Boiler interface point for new equipment cooling and miscellaneous uses
- New GQCS interface point for equipment cooling and miscellaneous uses
- ASU and CPU new interface points for miscellaneous uses

The service water cooling system consists of:

- One 400 mm (16 inch) strainer, twin basket, 1,136 m^3/hr (5,000 gpm), with manual backwash, to remove particles larger than 4.8 mm (3/16 inch)
- Two 1,136 m^3/hr (5,000 gpm) horizontal centrifugal pumps, one operating and one standby

Service water is pumped to individual equipment coolers in the Service Water Supply pipe, passes through each cooler and is collected in the Service Water Return pipe. The heated service water is discharged into the main cooling tower pump basin as makeup water. Excess water is discharge as tower blowdown to the river.

3.7.5 Compressed Air System

The existing compressed air system is not considered oil-free so a new instrument air and service air system is provided. The new system consists of:

- Three rotary screw, oil-free, 8.6 barg (125 psig) discharge pressure, 5,100 inlet m^3/hr (3,000 icfm) compressors
- Two heatless, 7,234 Nm^3/hr (4,500 scfm) air dryer skids, dewpoint of -40°C (-40°F).
- Two 4.26 m^3 (1,125 gallon) instrument air receivers
- One 4.26 m^3 (1,125 gallon) service air receiver

Two compressors will operate continually with the third compressor operating in load/unload modes as system demand dictates. The system will be cross-tied to the existing compressed air system through a controlled interface to prevent air with oil entering the new piping system.

Instrument air and service air will be distributed to the collective interface points at the Boiler, GQCS, ASU and CPU "islands." Instrument air piping will be ASTM A312 TP 304 stainless steel. Service air piping will be ASTM A106 Gr. B carbon steel pipe.

3.7.6 Stack

A new 137.5 m (451 ft) tall concrete chimney will be provided. The stack is designed to discharge monitored volumes of flue gas during unit startup and the transition to oxygen-fired status and to discharge flue gas and carbon dioxide during normal shutdown. In addition the stack will discharge small, monitored volumes of non-condensable gases during normal operation.

The stack will consist of:

- Outer reinforced concrete shell (27.6 MPa [4,000 psi] design) per ACI-307
- FRP inner shell liner per ASTM D5364
- FRP breeching duct
- Two, 360-degree test platforms with one hoist
- Test, CEMS and opacity ports, FRP construction
- One full concrete roof platform with Type 316L stainless steel hatch
- Aviation lighting, two levels of three medium intensity strobe lights
- Chimney electrical system
- Lightning protection

3.7.7 Coal Handling System

Existing Coal Handling System

The existing CHS currently serves Unit 3 (Boiler 5) burning 100% PRB coal. Unit 3 will continue to burn only PRB coal for any future operations.

PRB coal is currently delivered to the plant by river barges, while bituminous coal is delivered by truck. No provisions for accurate blending of bituminous and PRB coal are presently provided in the existing system.

PRB coal is unloaded from the barge via a coal bucket into the barge unloading hopper. A belt feeder installed below the hopper transfers the coal to the 91.4 cm (36") Conveyor E rated at 454 tonne/hr (500 ton/hr). Conveyor E transports the coal to the Breaker Building where it discharges to Belt Feeder F. This feeder releases coal to a two-position flop gate diverter that can send the fuel to either the breaker or to the tail of Conveyor D, which discharges to the Yard Hopper.

The breaker inlet is furnished with a grizzly classifier that directs oversize coal to the breaker while the finer particles bypass the breaker and are mixed with the crushed product, then discharged onto the 454 tonne/hr (500 ton/hr) Conveyor B. Conveyor B elevates the ready product to the Tripper Gallery where coal is discharged from Conveyor B onto the Tripper Conveyor C. The Coal Tripper Car unloads coal from Conveyor C into the boiler coal bunkers.

The Yard Hopper that is fed by Conveyor D provides surge capacity to allow scraper type earth moving equipment to load out coal for transfer to the yard stockpile.

Reclaiming of coal from the Coal Yard is performed through the Reclaiming Pit/Hopper that is furnished with a grate on ground level and an underground belt feeder. This feeder discharges onto Conveyor A that transports the reclaimed coal to the Breaker Building where it is unloaded onto Belt Feeder F for further processing as described above.

Repowered Plant Coal Handling System Configuration

The existing CHS will continue to be used to serve Unit 3 (Boiler 5) and Unit 4 (new Boiler 7). Unit 3 will be supplied with only PRB coal. Unit 4 will burn primarily bituminous coal, but will be able to accommodate a limited blend of PRB coal as well.

Besides providing coal directly to Unit 3, the barge unloading system will be also used for maintaining the PRB coal pile inventory and for on-line blending of PRB coal with bituminous coal for Unit 4. Supply of PRB coal from the yard pile to Unit 3 Boiler 5 could be provided also through the existing reclaim hopper, if required.

Bituminous coal for Unit 4 will be delivered to the plant by trucks and a pile of bituminous coal will be formed by yard machines. Yard machines (dozers, scrapers) will be used to transfer the coal from this pile to the existing reclaim hopper.

Concurrent operation of Unit 4 on either100% bituminous coal or bituminous coal/PRB coal blend, and Unit 3 on 100% PRB coal requires two (2) shifts of the CHS operation, each shift for one (1) unit only.

Crushed coal will be transported by the existing Conveyor B to the area of the existing Conveyor C tail section. A new transfer chute and gate arrangement will be provided in this area for transfer of coal to a new Belt Conveyor G that will transport the fuel to the new transfer house constructed at the new Boiler 7 building.

Construction of the new transfer chute and gate in the Conveyor C tail section will require to extend further the Conveyor B head section to create sufficient headroom required to feed in the new transfer chute and gate and provide the transfer of PRB coal onto existing Conveyor C for Unit 3.

Routing of the new Conveyor G will be provided above the existing turbine building roof. Blended coal will be discharged by Conveyor G onto Unit 4 tripper/cascading conveyor.

The new Conveyor G will be enclosed by hood covers. An outside walkway will be provided along the enclosed Conveyor G for service and maintenance purposes.

Blending of bituminous coal and PRB coal for Unit 4 will be provided by two (2) scenarios as follows:

Blending Scenario A (more accurate)

Existing Conveyors E and A will be furnished with new belt scales to monitor the flow rates of bituminous and PRB coals. Bituminous coal will be transferred by the reclaim hopper belt feeder onto existing Conveyor A that is discharging to the existing Belt Feeder F. The PRB coal will be transferred from the barge to the Feeder F by the existing Conveyor E. Blended on Feeder F fuels will be discharged to the existing Coal Granulator/Crusher.

Scenario B (less accurate)

Yard machines will be used to transfer both bituminous coal and PRB coal from the corresponding coal piles into the existing yard reclaim hopper when loading coal from barge is not available. The blending coal ratios will be controlled by the number of loader scoops of each fuel. Blended coal will be transported by the existing Conveyor A to the Breaker Building.

3.7.8 Water and Wastewater Treatment

Makeup Water

Sources of Makeup Water

The Illinois River is the primary source of makeup water, supplying water for the following uses:

- Screen and strainer backwash
- Cooling tower makeup (main cycle and GQCS)
- GQCS makeup (WFGD, DCCPS, ASU/CPU)
- Equipment cooling
- Equipment washdown
- Coal handling dust suppression
- Bottom ash and fly ash handling

The River Water analysis is shown in Table 3-6.

Table 3-6
River Water Analysis

Analysis Parameter (all mg/l unless noted otherwise)	Typical	Range	
		Min	Max
pH	7.9	7.1	8.2
Specific Conductivity, μS/cm	630	530	810
Total Dissolved Solids (TDS)	418	372	478
Total Suspended Solids (TSS)	95	11	226
Silica, dissolved	4	1.1	9.2
Chloride (total)	57	39	73
Fluoride (total)	<1	< 0.25	< 1
Sulfate (total)	78	61	95
Nitrate (total) as CaCO3	< 3	< 3	< 3
Phosphorus (total) as CaCO3	< 1	< 1	< 1
Sodium (total)	34	21	52
Potassium (total)	5 est	2 est	10 est
Calcium (total) as CaCO3	171	146	190
Magnesium (total) as CaCO3	114	78	150
Copper (total)	< 0.01	< 0.01	< 0.01
Iron (total)	1.5	0.4	3.8
Aluminum (total)	2.0	1.67	2.4
Barium (total)	no data	est 0.2	est 0.5
Manganese (total)	0.1	0.04	0.15
Total Hardness as CaCO3	271	246	340
Alkalinity (Carbonate), ppm as CaCO3	< 1	< 1	< 1
Alkalinity (Bicarbonate), ppm CaCO3	196	159	222
Dissolved Oxygen	7	7	7
Turbidity, NTU	no data	est 30	est 90
Total Organic Carbon (TOC) - estimated	5	2	7
Biochemical Oxygen Demand (BOD)	<4		
Chemical Oxygen Demand (COD)	6.6		
Oil & Grease	<3		
Water Temperature, °C (°F), estimated	21 (70)	1.7 (35)	32 (90)

Well water is used directly (without treatment) for:

- Steam cycle demineralizer influent
- Coal handling dust suppression
- Fire protection (some outside hydrants)
- Potable water

City water is used directly (without treatment) for:

- Fire protection makeup
- Unit 4 floor wash

Treatment of Makeup Water

As noted above, well water and city water are used directly, without additional treatment. River water, on the other hand, is subject to several processing steps, depending on the final use:

- All of the river water passes through intake screens. The screens are backwashed using their own inlet water. The backwash water is then discharged directly back to the river.
- The Unit 3 condensers use some of the screened water, without additional treatment.
- The balance of the river water, downstream of the screens, is pumped through various strainers, for use in high pressure service water (coal handling dust suppression, pyrite sluicing, air compressor cooling, floor washing), low pressure service water (equipment cooling, main cooling tower supplemental makeup, bottom ash seal, and Unit 4 GQCS), and ash sluicing water (Unit 3 ash handling, Unit 3 condenser vacuum ejectors) systems. The strainers are backwashed using their own inlet water.
- The Unit 4 GQCS system uses low pressure service water for various purposes and the treatment requirements vary, as indicated below:
    - No Additional Treatment - WFGD makeup (ME wash, gypsum dewatering, humidification water)
    - Clarification - ASU/CPU cooling tower
    - Clarification and Softening - DCCPS ME wash, DCCPS reagent prep, and DCCPS cooling tower supplemental makeup
    - Clarification, Ultrafiltration, and Reverse Osmosis - CPU process water

- The Unit 4 GQCS water treatment process main equipment components, chemical reagents, and byproducts are briefly presented below:
  - Clarification
    - Equipment: Reaction tank, solids contact clarifier, sludge recirculation and forwarding pumps, filter presses for sludge dewatering, pumps for sludge recirculation and filter press feed.
    - Chemical reagents: Ferric chloride (coagulant), polymer (flocculant/coagulant aid)
    - Byproducts: Filter cake (approximately 50% solids, chemically "fixed", expected to pass Toxicity Characteristics Leaching Procedure test).
  - Softening
    - Equipment: Ion exchange softener
    - Chemical reagents: Salt solution for regeneration
    - Byproducts (possibly use as WFGD makeup): Regenerant waste
  - Ultrafiltration and Reverse Osmosis
    - Equipment: Cartridge filters, ultrafiltration units, tanks, reverse osmosis feed pumps, and booster pumps, reverse osmosis units.
    - Chemical reagents: Possible reagents are sodium hypochlorite, acid, caustic, antiscalant, sodium bisulfite, detergent
    - Byproducts (use as WFGD makeup) : Ultrafiltration backwash, reverse osmosis reject (concentrated river water)
    - Byproducts (offsite processing): Rinses from chemical cleaning of reverse osmosis units.

Wastewater Treatment

Liquid effluent limitations for discharge to the Illinois River are identified in Table 3-7. The Unit 4 liquid effluents will not be discharged to the existing on-site ash ponds. Most of the Unit 4 WFGD and associated DCCPS system liquid waste will be recycled for fly ash wetting or reevaporated in the flue gas to the maximum possible extent to minimize high chloride waste streams requiring external treatment. Some Unit 4 streams, such as the main cooling tower and the ASU/CPU cooling tower blowdown, will be directed without further treatment to the discharge flume. These streams consist primarily of river water which has been concentrated due to evaporation in the cooling towers, with some small amounts of various circulating water feed chemicals (e.g. antiscalant, biocide, sulfuric acid, etc.) present. The ASU/CPU cooling tower makeup water portion of this stream will also have been softened, thereby exchanging sodium for calcium and magnesium ions. The other Unit 4 wastewater streams will be treated prior to release to the discharge flume.

Table 3-7
River Discharge Limits

Analysis Parameter (mg/l unless noted otherwise)	Criteria
Chloride	< 250
Sulfate	< 250
Fluoride	< 1.4
Phosphate	< 1.0
Ammonia, as N	< 4.54 (summer) < 2.03 (winter)
pH	6.0 – 9.0 standard units
Total Dissolved Solids	< 500
Oil & Grease	< 10 average < 15 max instant.
Total Suspended Solids	< 15 average < 30 max instant.
Aluminum	< 0.087
Antimony	< 0.006
Arsenic	< 0.05
Barium	< 1.0
Beryllium	< 0.004
Boron	< 1.0
Cadmium	< 0.012
Chromium, total	< 0.05
Cobalt	< 1.0
Copper	< 0.021
Iron	< 1.0
Lead	< 0.05
Manganese	< 0.15
Mercury	< 0.000012
Nickel	< 0.0963
Selenium	< 0.01
Silver	< 0.1
Thallium	< 0.002
Zinc	< 0.1426
Nitrate-Nitrogen, as N	< 10.0
Cyanide	< 0.1
Phenols	< 0.001
Hardness Dependent Metals Assumed	< 200 as CaCO3

Two distinct wastewater treatment processes are currently proposed for Unit 4 operations. The collection method, main equipment components, chemical reagents, and byproducts for each process are briefly presented below.

CPU Wastewater Treatment System (CPU WWTS)

The CPU WWTS includes pH adjustment and mercury polishing for the CPU Process Wastewater.

- Collection method: pumped directly from the CPU process systems
- Equipment: Cartridge filters, ion exchange vessels charged with specialized mercury polishing media, pumps
- Chemical reagents: Sodium Hydroxide (NaOH) for pH adjustment
- Byproducts:
    - Media backwash (only to occasionally "fluff" the media)
    - Removal of spent media for offsite regeneration and replacement

Unit 4 Wastewater Treatment System (Unit 4 WWTS)

The Unit 4 WWTS includes physical-chemical treatment of multiple wastewater streams.

- Collection method: Wastewater is pumped to an equalization tank from the DCCPS cooling tower, the CPU WWTS, and from the following other Unit 4 processes: steam cycle (sampling, condensate, blowdown, and miscellaneous drains), demin sumps, and coal handling dust suppression. Oily wastes are treated in an oil/water separator prior to being combined with other process wastewater streams.
- Equipment: Equalization tank, reaction tank(s), solids contact clarifier, sludge recirculation and forwarding pumps, filter presses for sludge dewatering, pumps for sludge recirculation and filter press feed.
- Chemical reagents: Ferric chloride (coagulant), organosulfide (metal precipitation), polymer (flocculant/coagulant aid).
- Byproducts: Filter cake (approximately 50% solids, chemically "fixed", expected to pass Toxicity Characteristics Leaching Procedure test) and waste oil, both of which are trucked off-site for final disposal.

Condensate Polishers

The repowering project will provide new condensate polishers, to maintain the purity of the condensate. Deep bed ion exchange vessels will be provided, to replace the existing out-of-service pre-coat type condensate polishers. Regeneration of the polishing resin will be done off-site under a service contract.

3.8 *Electrical and Control Systems*

3.8.1 Overall Plant Electrical Design

The 138 kV switchyard will be expanded to provide a new overhead distribution line to supply power to a new Unit #4 Aux Transformer. The switchyard expansion, overhead line, and Aux load primary metering is designed and supplied by Ameren T&D. Additionally, a number of existing overhead transmission and distribution lines need to be re-routed to free up plot space for new project equipment. These re-routes will be handled also by Ameren T&D.

One two-winding mineral oil-filled 100MVA auxiliary transformer will be provided to step down the voltage from 138kV to 13.8kV. A 4,000A, 63kA non-seg bus duct will connect the transformer secondary to new outdoor 13.8kV switchgear for distribution to the ASU, CPU, Boiler, and GQCS islands via 2,000A underground duct bank feeders.

Power to the new ASU/CPU Cooling Tower will be feed from an ASU island 4,160V Motor Control Center (MCC). A small electrical power distribution room containing a 4,160V MCC and 480V MCC located near the cooling tower will supply electrical power to the cooling tower loads.

Power to the new DCCPS Cooling Tower will be feed from a CPU island 4,160V MCC. A small electrical power distribution room containing a 4,160V MCC and 480V MCC located near the cooling tower will supply electrical power to the cooling tower loads.

The remaining new BOP equipment will be fed from a single new 4,160V MCC located in a new BOP electrical power distribution room. The MCC will be supplied from an existing 4,160V switchgear breaker that derives its electrical power from the existing Unit #4 main auxiliary transformer. The 4,160V MCC will distribute power to the medium voltage motors for the main cooling tower and the instrument air compressors, as well as three step-down transformers that supply 480V MCC's. One of the 480V MCC's is devoted to essential service loads, and is backed up by a 1,600kW diesel generator currently available for use at the plant. This essential service 480V MCC will also feed the essential service MCC's supplied with each island.

Existing BOP equipment will continue to receive power from their existing sources. New BOP loads will be fed from new electrical distribution equipment as described above. The new BOP UPS loads are minimal and therefore will be fed from the existing UPS system.

3.8.2 Instrumentation and Control (I&C) Systems

I&C Philosophy

The I&C control philosophy will be applied to all systems comprising the new unit configuration and will include:

- Common/consistent units of measure application
- Standardized HMI display formats, text, color and display methods
- Common/consistent logic and functional control designs
- Standardized alarm management techniques, rationalization and alarm summary displays
- Common signal/equipment segregation and partitioning techniques
- Consistent signal, processor, communication and power supply redundancy approaches
- Consistent interrogating voltages and signal formats
- Consistent methods, materials and accessories for instrumentation installation and mounting
- Consistent instrument and control element vendor/models
- Hardwired signal exchange of critical signals among the unit control systems and equipment packages
- Active participation by plant staff in the development of HMI displays

Boiler and Combustion I&C

A Distributed Control System (DCS) is provided for the plant control system (PCS) which serves as the main control system and human-machine interface (HMI) for regulatory control, monitoring, data acquisition, storage and display. The PCS is comprised of the Boiler Control System (BCS), Burner Management System (BMS), Gas Quality Control System (GQCS), Turbine Control and Balance of Plant (BOP) with interface to the independently controlled ASU and CPU control systems. The PCS also interfaces with all other control sub-packages provided as part of the operation of the Boiler and GQCS systems.

The PCS utilizes a common control platform while using existing I/O hardware for the Turbine and BOP systems. The ASU and CPU control systems are interfaced via an OPC server connection for data exchange to the PCS. Critical interlocks, control signals, and alarms required between any of the control packages employ hard-wired I/O for maximum reliability. Hardwired emergency trips (e.g. Boiler Master Fuel Trips, and Turbine Generator trips) are implemented at the PCS central HMI location. Non-critical signal exchanges between control packages and between the PCS employ soft communication techniques (e.g. ModBus, OPC, Ethernet). In order to maximize system reliability, rendundancy is provided for control processors, data highways, interface controllers and power supplies. The conceptual system architecture is shown in Figure 3-10.

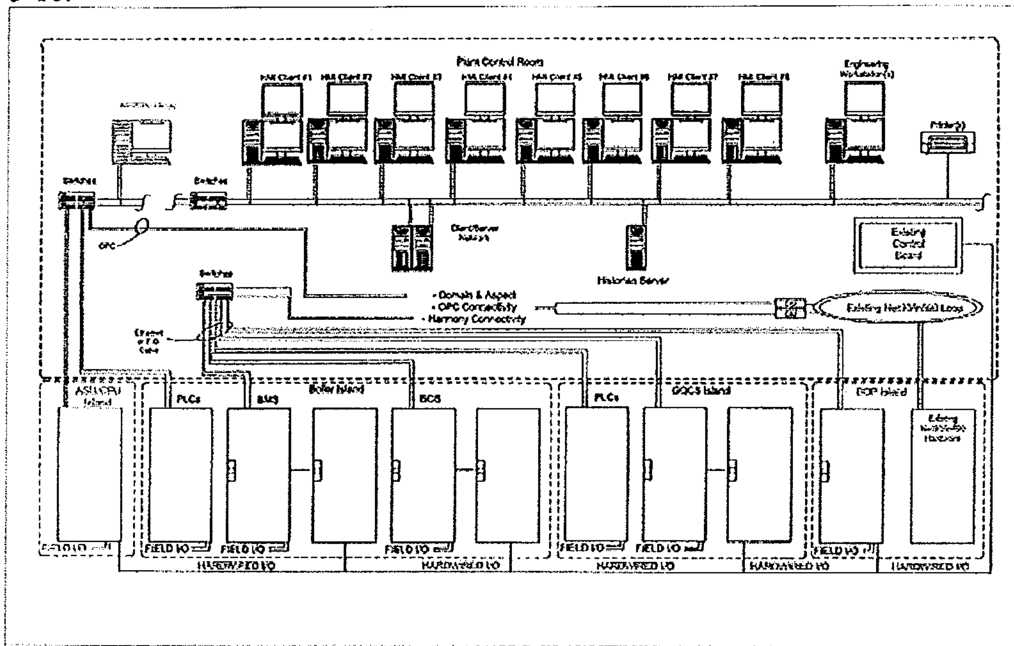

Figure 3-10
Plant Control System Architecture

Instrumentation manufacturers and model numbers/series are standardized as much as possible. Process measuring instruments are of microprocessor-based (Smart) design utilizing HART protocol.

The plant instrumentation and the PCS are designed to achieve the following:

- Maximize the integration of control sub-packages resulting in a comprehensive PCS that optimizes staffing levels.
- Apply a consistent control and instrumentation philosophy to the maximum extent possible throughout the plant.
- Standardize approaches to operating functions such as protection, automatic control manual control and monitoring.
- Utilize operating logic that minimizes operator action.

- Collect all information essential to plant operation, performance and maintenance in a central location.
- Provide performance monitoring subsystems that evaluate overall plant and major equipment performance.
- Apply techniques to prioritize alarms and suppress nuisance alarms.
- Minimize operator interaction through application of automation techniques (e.g., startup sequence blocks).
- Minimize the likelihood that any single failure results in a plant trip.

A high-fidelity simulator is also provided to facilitate operator training and increase operation proficiency. The simulator integrates the various dynamic models of the plant with the programmed control strategies of the PCS, ASU, and CPU control systems. The simulator environment including HMI's, consoles, and hardware is designed to duplicate the plant control room. The simulator emulates and provides accurate real-time responses for start-up, shutdown, varying operating loads and abnormal conditions of the plant.

ASU and CPU I&C

The ASU and CPU facilities will be designed for minimal but full time on-shift staffing. The operator will be able to start, control and stop all major pieces of equipment in the Facility from the Seller supplied control room. The Facility is equipped with suitable electronic instruments, process analyzers, and control devices to ensure safe and efficient Facility operation.

Equipment protection monitoring signals as well as Facility performance variables will be monitored and logged. This will allow the operators to monitor and trend the performance of the Facility over time and be able to make predictive maintenance calculations of the equipment. This enables the operating staff to better plan, coordinate and schedule any required maintenance.

Facility shutdown interlocks shall be designed for safety and to protect the equipment. If a shutdown interlock is activated, the Facility will automatically shutdown in a safe mode. Once the cause of the shutdown has been identified and fixed, the interlock will be cleared and the Facility can be restarted.

Balance of Plant I&C

The new unit configuration significantly increases the amount and variety of equipment, controls, alarms and monitoring items to be managed by the unit Operator. As such, emphasis must be placed on:

- Migrating the existing unit control, alarm and monitoring points to a single platform and interface

- Maximizing training and familiarization of unit personnel with the new systems.

To that end, much of the BOP I&C scope is focused upon migrating existing stand-alone systems into the common plant distributed control system (DCS) platform and supporting the development and provision of a high fidelity simulator for the project. Activities included in the BOP I&C modifications are:

- Migration of the existing unit sequence of events and alarm lamp box points to the DCS. The sequence of events points for the unit will be implemented in the DCS and applies a GPS clock for time stamp synchronization.
- Migration of unit-specific Main Control Board (MCB) indicator, recorder and indicating light values and statuses to the DCS
- Replacement of the hardwired motor controls with motor control logic and IO integrated into the DCS
- Provision of new Operator consoles for interface to the DCS
- Modification to existing BOP DCS process control and IO cabinets and hardware for integration into the new unit DCS platform
- Addition of new BOP DCS cabinets for migrated and new functions in support of the new unit configuration
- Replacement of the existing DCS loop (network) cabling for integration into the new platform
- Migration of the turbine water induction protection system into the DCS, including the addition of redundant feedwater heater level transmitters
- Migration of existing, key local control loop functions into the DCS
- Addition of redundant sensors/transmitters for critical control functions, such as deaerator storage tank level
- Replacement/refurbishment of existing unit instrumentation and control elements
- Integration of new vendor package programmable logic controllers via screen emulation in the DCS
- Development of steam turbine-generator and BOP dynamic models for a new high fidelity simulator
- Provision of simulator consoles for both training and configuration testing purposes that are essentially identical to the new DCS consoles

4.0 COST ESTIMATE AND SCHEDULE

4.1 *Project Cost Estimate*

The Project Cost Estimate was developed from the ground up, with each island supplier providing the costs for their respective island scope. The Project Division of Responsibility (DOR) was used as the guiding document to define scope splits between the participants. The specific estimating methods used varied between the islands, based on each participant's standard work processes, but generally encompassed the following.

- Preliminary equipment designs were prepared based on the Design Basis Document and other key process information contained in the Phase 1 engineering deliverables. In the majority of cases equipment was quoted by Vendors normally utilized by each island supplier in response to extensive technical/commercial request for bid packages. These quotes were validated against recent purchase information and tuned to reflect the best estimate of final price paid in a "real purchase" scenario.

- Where vendor quotes were not obtained, costs were estimated based on experience and internal cost database information.

- Material take offs (MTO's) for bulk items, including site preparation, piping, electrical, structural steel (pipe racks) and concrete foundation work, were prepared. These MTOs were used to feed cost estimate build-ups utilizing labor rates and productivity assumptions tuned to site-specific conditions. In many cases, local area Contractors who have serviced Ameren on recent large projects were used to independently develop estimates as validation.

- For those items not covered by vendor quoted subcontracts, engineering and installation labor was estimated based on the DOR, MTO's, and schedule using in-house information for each island supplier.

- Integrated project-wide (all islands included) engineering and construction schedules were developed and were utilized to assist with understanding work coordination and site density assumptions.

- Craft labor rates were based on labor survey information gathered from the local union halls.

- Management reserve was included based on a Monte Carlo analysis, with inputs from each participant for their respective cost items.

Table 4-1 presents a summary of the capital cost estimate results.

Table 4-1
Project Capital Cost Estimate Summary

Cost Category	Total Cost ($1,000's)
Direct Costs	$ 617,048
Indirect Costs	$ 124,147
Design Engineering	$ 103,024
G&A	$ 8,914
Fee	$ 14,975
Ameren Costs	$ 80,198
Escalation	$ 51,612
Construction/Startup Power	$ 2,462
Total EPC Costs	$1,002,378
Management Reserve	$ 83,693
Total Phase 2, 3, 4 Costs	$1,086,071
Phase 1 Costs	$ 12,554
Total Project Costs	$1,098,625

4.2 *Project Economic Evaluation*

This section is still under development by AER.

4.3 *Preliminary Schedule*

A preliminary Integrated Master Schedule (IMS) was prepared for the Project, built up and synchronized from individual schedules for each participant, including both engineering and construction activities and inputs. Interface milestones between the islands and participants were created based on information needed to complete each major design aspect or construction package within each island. These milestones were integrated into the IMS so that the associated activities are logically tied, but final agreement on key dates is still under discussion and the schedule will continue to be updated during subsequent Project phases.

The schedule does not include the Alliance pipeline and sequestration project schedule in detail, but selected Alliance milestones have been added to the IMS. Schedule integration with the Alliance is accomplished by contacting them on a monthly basis to review the status of their milestones and those selected activities that are carried in and impact the IMS.

The current revision of the full IMS contains approximately 14,000 individual activities identified through Phase 4 of the Project.

5.0 PROJECT RISK AND OPPORTUNITY ASSESSMENT

5.1 *Project Risks*

A Risk Management Plan has been developed for the Project, based primarily on AER's internal risk management procedures. Pursuant to those procedures, a risk matrix has been developed identifying known project risks.

A number of issues have been identified during Phase 1 that require further evaluation in Phase 2 to better quantify and mitigate Project risks and to allow the Project to take advantage of potential opportunities.

5.2 *Plant Performance Enhancements*

5.2.1 Auxiliary Power

This section is intended to describe some of the steps that may be taken in Phase 1B or Phase 2 (FEED) to reduce the aux power and thereby improve overall plant performance.

Table 5-1 shows the current auxiliary power prediction compared to the proposal estimate, based on performance coal and average ambient conditions. At the conclusion of the pre-FEED, an additional 15.7 MW of aux power has been identified when compared to the proposal.

Table 5-1
Auxiliary Power Comparison

	Current kW	Proposal kW	Increase kW	Phase 2 Target kW
Total	80,100	64,384	15,715	74,000 to 77,300

Basis of the Proposal Estimate

Boiler and Auxiliaries (includes GQCS)

<u>Fan Power:</u> The ID, Secondary and Primary fan power for the proposal was calculated using the proposal heat and mass balance flows assuming 80% fan efficiency and 95% motor efficiency. In addition, no margins were included in the proposal to cover any differences between calculated (theoretical) and actual fan performance.

Pulverizers: The preliminary design selected four B&W PGG 67G pulverizers with three in service at full load. During pre-FEED the comparison of current to proposal power it was discovered that the pulverizer power shown in the proposal table was erroneously based on two pulverizers in service instead of three. This represents a 200 kW underestimate (error).

GQCS: The GQCS estimate includes ash handling, baghouse (PJFF), wet scrubber and slurry prep system, gypsum system (WFGD), and the Polishing WFGD/DCC (now called DCCPS). The power estimate was factored from a previous project to account for scale but no design calculations were made due to limited time. The estimate for the Polishing WFGD/DCC was based on scaled down estimates for B&W PGG-AL's 800 MWe Integration Study and work in progress on a 700 MWe Reference plant design co-funded by EPRI.

ASU

The ASU power consumption for the proposal did not include any miscellaneous loads such as line/transformer losses, HVAC, lighting, etc.

CPU

The CPU power consumption for the proposal did not include any miscellaneous loads such as line/transformer losses, HVAC, lighting, etc.

Balance of Plant (existing equipment)

The balance of plant for the remaining existing equipment was estimated based on a percentage of gross power. No site information was available at the time. The proposal estimate is about 2.8% of the gross power. It was assumed that the auxiliary power for a new air-fired plant is about 8% of the gross power. The boiler and AQCS were assumed to be about 65% of that power leaving about 35% for the BOP. It was also assumed that the existing BOP would be refurbished to achieve modern performance.

Balance of Plant (additional due to oxy-combustion)

The ASU and CPU cooling were a very rough estimate scaled down from previous studies for greenfield plants. The cooling for the Polishing WFGD/DCC was considered as part of that system and included in the GQCS estimate.

Pre-FEED Predictions and Comparison with Proposal

Process Heat and Mass Balance

Several issues have changed the process heat and mass balances. In the following discussion, performance conditions assume typical coal analysis and average ambient conditions.

- The performance (design) coal properties selected early in Phase 1 are different from those used for the proposal. The shaded columns show the current typical coal analysis and the typical analysis used for the proposal. The impact of the differences on equipment sizing and auxiliary power will be discussed on a component basis.

- After initially providing recycle heater performance that was consistent with proposal assumptions, the vendor advised that their internal leakage calculation was erroneous and it was increased from 6.9% to 9.5%.

- It was decided that worst and best coals would be considered and a blend of up to 30% PRB was checked and found to be acceptable with minimal cost impact.

- The design would focus on low capital cost to maximize the ability to achieve the cost targets, which generally results in lower efficiency as well. This is particularly relevant to the large flue gas fans in which the lower cost single speed centrifugal fans selected in the pre-FEED are less efficient than variable-pitch axial fans that would give the higher efficiencies assumed in the proposal aux power estimate.

- The design would focus on low capital cost to maximize the ability to achieve the cost targets, which generally results in lower efficiency as well. This is particularly relevant to the large flue gas fans in which the lower cost single speed centrifugal fans selected in the pre-FEED are less efficient than variable-pitch axial fans that would give the higher efficiencies assumed in the proposal aux power estimate.

Some of these factors will be addressed in Phase 2 to reduce cost and auxiliary power as much as possible.

Boiler and Auxiliaries (includes GQCS)

Several factors have contributed to the increase in boiler auxiliary power. These factors are detailed below.

Fan Power: The reduction in heating value for the typical coal and the increase in recycle heater leakage produced flows under performance conditions that are significantly increased compared to the proposal. In addition, the fans operate at a lower efficiency under performance conditions (about 65% compared to 80% assumed in the proposal). The fan efficiency of 80% reflects either a centrifugal fan with a variable speed drive (VSD) or an axial fan with variable blade pitch, both of which are generally not considered low capital cost options. The low capital cost option considered in Phase I for the fans is two speed centrifugal fans with variable inlet vanes. These fan designs typically have a fan efficiency of approximately 65% at the full load operating point. Since the fans are operating down on their efficiency curve, experience has shown that fan vendors are less accurate in meeting their predicted performance so margin has been applied to their predicted power values compensate for vendor inaccuracy. The combination of these factors increased fan power by about 3,355 kW compared to the proposal estimate.

Pulverizers: The reduction in fuel heating value for the typical coal requires 11.4% more fuel to be handled by the pulverizers. This fuel difference along with an increase in coal fineness requirements (to improve combustion efficiency) result in an additional 350 kW in pulverizer power consumption over the proposal estimate.

GQCS: The total GQCS aux power came out about the same as the estimate in the proposal. The factors mentioned above that have impacted the other areas such as the difference in fuel properties, increase in recycle heater internal leakage, and the sizing of equipment to accommodate a wider range of properties (i.e. worst coal and 30% PRB blend) also impacted the GQCS aux power estimate. However, the scaled down estimate for GQCS aux power put in the proposal appears to have been conservative enough to absorb these factors and so the Phase 1 (pre-FEED) aux power is relatively close to the proposal estimate.

Balance of Plant (existing equipment)

The original existing BOP aux load was simply estimated for the proposal, based on an assumed typical percentage of gross output. During Phase 1, a more rigorous analysis of the existing auxiliary loads was completed by URS, based both on historical performance as well as an individual load list buildup, and results in the higher final BOP aux load figure shown in Table 5-1. Besides being the result of more rigorous evaluation, the increase in auxiliary load can also be partly attributed to the following factors:

- The Meredosia site is a multiple unit site, with a number of miscellaneous components planned for reuse, but designed to serve the entire common plant. Since these loads are not optimized for Unit 4 operation only, auxiliary power consumption will be higher than expected for a new plant.

- Many of the existing auxiliary loads are original equipment that are planned for reuse without refurbishments that would improve performance. The original proposal estimate was based on modern new and clean performance.

- Because the original Unit 4 boiler was oil-fired, the original proposal assumption of 8% of gross output for total existing aux load appears reasonable. In fact, existing Unit 4 performance indicates that actual baseload auxiliary power has been around 7% of gross output. However, with the new Boiler 7, additional loads for equipment associated with coal-fired applications (e.g., coal handling, ash handling, etc. – existing equipment, but currently only associated with Units 1, 2, and 3) must be included, and were likely not adequately accounted for in the proposal estimate.

Balance of Plant (additional due to oxy-combustion)

The additional auxiliary power estimated for new BOP equipment related to oxy-combustion was limited to cooling of the ASU and CPU in the proposal stage. It was based on scaled down estimates from previous studies for larger plants that used adiabatic compression with the heat integrated into the steam cycle to produce additional gross power. During Phase 1 it was determined that the existing turbine-generator is limited to about 210 MWe of gross power so the degree of integration of the ASU and CPU heat was found to be defined by the amount of heat needed to compensate for the steam required for oxidant heating and the flue gas reheaters. Thus the heat added to the steam cycle is essentially equal to the heat used, and that was determined to be less than the ASU and CPU heat available, therefore resulting in more waste heat and cooling than the proposal estimated. Additionally, the small scale of the unit and the desire to minimize capital led to the selection of isothermal compressors in the CPU (heat integration done in the ASU) which produce more unrecoverable waste heat than adiabatic compression and are less efficient (see ASU and CPU discussions). These factors resulted in overall higher ASU and CPU cooling loads and therefore higher auxiliary power loads for the resulting BOP cooling water components, contributing to the overall aux load increase by approximately 2,943 kW.

Beyond the cooling water issue above, several additional new loads were identified in Phase 1 that were not expected when the proposal was prepared. These include the following:

- Air compressors – the ASU has a significant instrument air demand that cannot be accommodated by existing compressors or by the ASU compressors which are at too low a pressure.

- Water and wastewater treatment equipment – due to permitting requirements and the increased makeup water requirements associated with the oxy-combustion process (mainly increased ASU/CPU cooling), additional equipment is required for treating both makeup water and wastewater.

Phase 2 FEED Steps to Reduce Auxiliary Power

The following describes work anticipated to be done early in Phase 2 of the Project to evaluate various design issues that may improve overall auxiliary power consumption. These issues are part of a larger scope than encompasses performance optimization or "value engineering" in general.

Boiler and Auxiliaries (includes GQCS)

<u>Fans:</u> Since the difference in coal properties is not likely to be changed and it is desirable to provide test flexibility and capacity for a wider range of coals than considered in the proposal, those effects cannot be reduced. However, there are options that can be pursued in Phase 2 that could result in a reduction in fan power as much as 2 MW with additional capital expenditure. The key items are:

- Work with the recycle heater vendors to reduce internal leakage.

- Consider fan configurations and drives to improve fan efficiency (e.g. centrifugal fans with variable speed drives and/or axial fans with variable blade pitch).

- Work with the selected fan vendor to reduce margins.

- Optimize flue design and arrangement as well as equipment design to reduce pressure losses which will decrease the pressure rise required by the fans.

ASU & CPU

Further optimizations that have the potential to lower the ASU and CPU power consumption will be done in Phase 2.

Balance of Plant (existing equipment)

The existing BOP equipment was extensively evaluated during Phase 1, and with few exceptions was found to be of appropriate capacity and in good condition for reuse in the repowered facility. Consequently, there is little value expected to be gained by replacing or upgrading existing components, so further evaluation during Phase 2 is expected to be minimal. In general, Phase 2 will only address component upgrade or replacement when and if existing equipment design is discovered after detailed design to be insufficient to supply the required utility conditions. Otherwise, the only specific evaluation issue planned specifically to target lower auxiliary power consumption is a study of the benefits of replacing existing motors with new high efficiency motors.

Balance of Plant (additional due to oxy-combustion)

In general, design efforts during Phase 2 are expected to result in somewhat lower BOP auxiliary power consumption, just due to better defined design criteria and the consequent reduction in design margins applied to final equipment sizing calculations. Beyond this, optimization of the DCCPS cooling tower and circulating water pump design will be evaluated, targeting a lower flow, higher temperature cooling tower design, which could reduce system auxiliary loads by as much as 500 kW.

5.2.2 Additional Performance Opportunities

Besides auxiliary power, several other plant performance related issues were identified during Phase 1 as potential opportunities for improvement. The following issues are expected to be addressed during Phase 2:

- Further optimization of heat integration between BOP and other islands. While additional heat integration may be difficult – as explained in Section 2.5 – further optimization (pressures, temperatures, etc.) may be possible.

- Additional steam turbine refurbishment or upgrades to improve plant performance and potentially allow additional heat integration. Note that estimated turbine performance degradation alone translates into approximately 1.2 percentage points in overall plant efficiency. Much of this performance loss could likely be recovered just from a turbine overhaul.

- Optimize boiler fan design and evaluate redundancy on boiler fan trains. Elimination of redundancy may improve both the cost and performance of the plant.

- Further evaluation of the benefits of overhauling/refurbishing existing equipment to improve performance. While the plant assessment report provided recommendations based on achieving and maintaining plant service life and reliability goals, additional performance benefits were not quantified.

5.3 *Plant Cost, Reliability, Operability, and Maintainability Enhancements*

While not specifically related to plant performance, many issues were identified during Phase 1 as potential opportunities for improvement in overall plant cost, reliability, operational flexibility, and maintainability. Further evaluation of the following issues may be addressed in subsequent Project phases.

- Existing steam turbine limitations and potential upgrades required to accommodate wider range of oxy-combustion plant operation.

- Auxiliary boiler capacity - whether to include building heating and other potential loads in capacity.

- Main boiler startup and auxiliary boiler fuel source - No. 2 fuel oil vs. natural gas.

- Upgrades of existing CHS equipment (additional crusher, feeders, etc.) and the impacts to main boiler design and coal handling system (CHS) to accommodate PRB coal blend. Boiler and CHS can currently accommodate limited mix of PRB, but will confirm in Phase 2 and will more thoroughly assess cost impacts for accommodating this blend.

- Cost and design impacts for eliminating air-firing capability (SCR accommodations) entirely.

- Use of truck storage (vs. permanent silo storage) for Trona, limestone, and other non-fuel consumables.

- Alternative landfill sites for ash/gypsum other than Duck Creek

- GQCS (WFGD and DCCPS mainly) materials of construction (reliability, maintainability, cost issues)

- Additional redundancy for systems which currently have non-redundant equipment

- Increase ASU O_2 storage to accommodate extended ASU outages

- Removal of CPU and ASU compressor buildings, with use of noise hoods for noise abatement

- Scope and function of high-fidelity plant simulator

- Elimination of copper from the feedwater system (includes replacement of LP feedwater heaters as well as change of ASU/CPU heat exchanger materials) to improve boiler water chemistry.

- Additional underground piping installation (vs. current general aboveground plan, especially in ASU/CPU areas)

- Features to allow extended and more efficient plant turndown

- Use of dry limestone injection vs. wet limestone slurry

- Installation of a new elevator to serve new Boiler 7

- Purchase of spare pumps (or rotating elements) and motors in lieu of overhauling existing equipment to minimize downtime after equipment failures. Mainly to be considered for large pumps (feedwater, condensate, circulating water, etc.)

- Plume abatement for new main cooling tower, as well as ASU/CPU and DCCPS cooling towers

- Transient analysis of LOx switchover (if ASU trips) and ability to continue uninterrupted oxy-combustion operation

6.0 PRELIMINARY PERMITTING AND NEPA

6.1 *Permits*

URS continues to work with the B&W PGG, ALPC and the URS design teams to develop needed information for air emission, solid waste generation, water use, and wastewater discharge data. This data is needed so Ameren-Environmental may determine the appropriate permitting strategy and what types of permits will be required. Ameren is writing permit strategy white papers for air, water, and solid wastes to provide management with options and potential impacts associated with those options. Ameren and URS are gathering data to determine the applicability of regulatory requirements under US EPA, Illinois EPA, Illinois DNR, and the U.S. Army Corps of Engineers.

6.2 *Environmental Information Volume*

Based on direction from DOE at the January 26, 2011 meeting at Ameren, URS is not developing an EIV document, but is providing information to DOE's Environmental Impact Statement (EIS) contractor, PHE. URS will provide the information as it becomes available for PHE's use in developing the EIS. Also, in accordance with DOE direction, PHE will conduct the field work needed to support the EIS, based on input from URS and Ameren.

URS has also provided data to PHE for the EIS to include the following:

- A technical memorandum with site-specific information needed to conduct field studies for ambient noise measurements
- Maps showing locations of impacts in and around the facility
- Map of the probable location of a natural gas line and ROW width if the project determines that one is needed; narrative descriptions of the existing plant and proposed modifications
- General arrangement plan
- Selected air permits
- Information on descriptions of processes, process inputs and outputs, and construction estimates.

Ameren has coordinated with PHE to conduct initial field work for the Ordinary High Water Mark, wetland delineations, traffic counts, noise measurements, and initial field survey for threatened and endangered species in and around Meredosia.

URS is working with Ameren to provide PHE with siting criteria for a potential off-site landfill, information on existing information regarding the facility's current operation to include permits, discharge reports, and operating procedures. Ameren will be discussing potential impacts to aquatic life in the river with the regulatory agencies to determine if field studies will be required in addition to obtaining clarification of regulatory requirements for barge unloading at Meredosia.

FutureGen 2.0 - Oxy-Combustion Project Cost Review
Proposal Cost vs. Phase 1 Cost State

Component	Total Project Cost Estimate at Proposal	Total Project Cost Estimate at Phase 1 Completion	Difference Drivers
B&W – Boiler and AQCS	$262M	$394M	•Assumed Foundations and HV Electrical by Others. •"Demonstration Quality" equipment. •Fuel Flexible Capability. •Structural Steel underestimated. •No A&G or Contingency estimated.
Air Liquide – ASU and CPU	$314M	$366M	•Increased ASU size for air leakage. •CPU lessons-learned from Callide. •No A&G or Contingency estimated.
AER/AE/EPC	$161M	$340M	•Stack, Cooling Towers, Transformers, Switchgear and Water Treatment not estimated. •Switchyard Construction and Transmission Line relocation not estimated. •Most of Condition Assessment findings not estimated. •No A&G or Contingency estimated.
TOTAL PROJECT	**$737M**	**$1.1B**	**$363M**