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ABSTRACT

The primary objectives of the FutureGen 2.0 Oxy-Combustion Large Scale Test Project were to site, permit, design, construct, and commission, an oxy-combustion boiler, gas quality control system, air separation unit, and CO_2 compression and purification unit, together with the necessary supporting and interconnection utilities. The project was to demonstrate at commercial scale (168MWe gross) the capability to cleanly produce electricity through coal combustion at a retrofitted, existing coal-fired power plant; thereby, resulting in near-zero-emissions of all commonly regulated air emissions, as well as 90% CO_2 capture in steady-state operations. The project was to be fully integrated in terms of project management, capacity, capabilities, technical scope, cost, and schedule with the companion FutureGen 2.0 CO_2 Pipeline and Storage Project, a separate but complementary project whose objective was to safely transport, permanently store and monitor the CO_2 captured by the Oxy-Combustion Power Plant Project.

The FutureGen 2.0 Oxy-Combustion Large Scale Test Project successfully achieved all technical objectives inclusive of front-end-engineering and design, and advanced design required to accurately estimate and contract for the construction, commissioning, and start-up of a commercial-scale "ready to build" power plant using oxy-combustion technology, including full integration with the companion CO_2 Pipeline and Storage project. Ultimately, the project did not proceed to construction due to insufficient time to complete necessary EPC contract negotiations and commercial financing prior to expiration of federal co-funding, which triggered a DOE decision to closeout its participation in the project.

Through the work that was completed, valuable technical, commercial, and programmatic lessons were learned. This project has significantly advanced the development of near-zero emissions technology and will be helpful to plotting the course of, and successfully executing, future large scale demonstration projects. This Final Scientific and Technical Report describes the technology and engineering basis of the project, inclusive of process systems, performance, effluents and emissions, and controls. Further, the project cost estimate, schedule, and permitting requirements are presented, along with a project risk and opportunity assessment. Lessons-learned related to these elements are summarized in this report. Companion reports on Oxy-combustion further document the accomplishments and learnings of the project, including:

A.01 Project Management Report which describes what was done to coordinate the various participants, and to track their performance with regard to schedule and budget

B.02 Lessons Learned - Technology Integration, Value Improvements, and Program Management, which describes the innovations and conclusions that we arrived upon during the

development of the project, and makes recommendations for improvement of future projects of a similar nature.

B.04 Power Plant, Pipeline, and Injection Site Interfaces, which details the interfaces between the two FutureGen projects

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1.0 EXECUTIVE SUMMARY

1.1 Summary Statement

The U.S. Department of Energy's (DOE) FutureGen 2.0 Program involves two projects: (1) the Oxy-Combustion Large Scale Test Project and (2) the CO_2 Pipeline and Storage Project. This report is focused on the Oxy-Combustion Large Scale Test Project as well as addressing interface considerations between the two projects.

The project was conducted as a partnership between DOE and the FutureGen Alliance with the active support of the State of Illinois and local community. The FutureGen Alliance is a non-profit consortium of companies with business interests in the coal industry, currently including Alpha Natural Resources, Anglo-American, Glencore, JoyGlobal, and Peabody Energy. In addition, numerous technology and service providers supported the project.

The FutureGen 2.0 Oxy-Combustion Large Scale Test Project successfully achieved all technical objectives inclusive of front-end-engineering and design, and advanced design required to accurately estimate and contract for the construction, commissioning, and start-up of a commercial-scale "ready to build" power plant using oxy-combustion technology including full integration with the companion CO_2 pipeline and storage site. Ultimately, the project did not proceed to construction due to insufficient time to complete related EPC contract negotiations and commercial financing prior to the expiration of federal co-funding, which triggered a DOE decision to closeout its financial participation in the project ("closeout decision"). While most commercial issues had been resolved at the time of the closeout decision, several interlinked commercial issues remained to be resolved (two litigation issues, several EPC contract issues, and final financing commitments). Had additional time been available, there was a high likelihood all remaining issues could have been resolved.

Among the project's accomplishments were:

- Secured approval from the Illinois Commerce Commission for 20-year power purchase agreements (PPAs) with two Illinois utilities. The cost of service agreements provide a guaranteed market for 100 percent of FutureGen 2.0's energy production and provided rate recovery for the added cost of carbon capture and storage. The PPAs were the first to be successfully negotiated under the Illinois Clean Coal Portfolio Standard.
- Developed a detailed design for the integration of oxy-combustion boiler technology provided by the Babcock & Wilcox company with air separation and CO_2 compression and purification technologies provided by Air Liquide; not only at steady state, but in startup, shutdown and during transient conditions.

- Developed an integrated approach to power plant operations, inclusive of CO_2 production from the plant, with the transportation and storage of CO_2. This included not only process controls integration, but also the conduct of an integrated hazards review that uncovered and resolved a number of critical technology interface issues.
- Developed detailed designs for the power plant islands. In addition to completion of a typical front-end engineering and design (FEED), the design was advanced to a much greater state of design detail. As a result, the project scored best-in-class during a formal project development readiness index (PDRI) review.
- Negotiated firm price contracts for all of the primary mechanical components within the islands, and in many cases executed those contracts on a limited notice to proceed basis in order to secure detailed vendor engineering data required for advanced plant design. This provided both cost and design surety as the definitive cost estimate was developed and the EPC contracts were negotiated.
- Negotiated and executed a project labor agreement (PLA) with the 17 craft labor unions to supply construction labor for the project. While the project did not proceed to full construction, the PLA governed early construction activities at the power plant. This agreement was designed to ensure that the project received the skilled staffing required for the construction effort, that work rules and work jurisdiction was negotiated and agreed in advance, and that the cost of labor for the life of the construction project was established and agreed. These points were critical to negotiation of the EPC contracts and to the surety of project cost, substantially increasing project financeability.
- Attracted a major utility, partnered with a class-leading equity investment fund, which together had completed first-level project due-diligence, and were initiating final due-diligence to support a firm equity commitment when the closeout decision was made.

1.2 Background

The primary objectives of the FutureGen 2.0 Oxy-Combustion Large Scale Test Project were to site, permit, design, construct and commission an oxy-combustion boiler, gas quality control system (GQCS), air separation unit (ASU), CO_2 compression and purification unit (CPU), together with the necessary supporting and interconnection utilities. The project was to be fully integrated in terms of project management, capacity, capabilities, technical scope, cost, and schedule with the companion FutureGen 2.0 CO_2 Pipeline and Storage Project.

In pursuit of this master objective, a set of performance milestones were stipulated by DOE in the Cooperative Agreements for each of the two projects. Those that fall within the scope of the Oxy-Combustion Large Scale Test Project are as follows:

- Submission to DOE of Power Purchase Agreements
- Completion of Front-End Engineering and Design (FEED)

- Submission to DOE of a definitive estimate of project cost
- Execution of Engineering Procurement and Construction (EPC), and Operating & Management (O&M) contracts
- Achieve financial close

1.3 Project Status as of the Cooperative Agreement Closeout

The status of each major Cooperative Agreement performance milestone as of receipt of the January 28, 2015 notice that the DOE had decided to closeout its financial support of the project (closeout decision) due to insufficient time remaining for project completion prior to expiration of the federal funding is discussed below. The full final scientific and technical report contains detailed information associated with each milestone as noted:

Submission to DOE of Power Purchase Agreements

On June 26, 2013, the Illinois Commerce Commission issued a final order that the power purchase agreements negotiated by the Alliance (the seller) and Illinois utilities, Ameren and Commonwealth Edison (ComEd) (the buyers) was approved. This led to each entity signing PPAs effective August 22, 2013—ahead of schedule. The PPAs are notable in that they are the first approved by the authority granted to the Illinois Commerce Commission under the Clean Coal Portfolio Standard. The PPAs are cost-of-service based and provide a market for 100 percent of FutureGen's electricity. The PPAs incorporate a pre-approved return on equity and enabled the Alliance to engage the commercial financing market as a long-term contracted asset. Feedback from financial markets on the PPAs was extremely strong.

The Alliance and Illinois Commerce Commission successfully defended an appeal in the Illinois First District Court of Appeals. A subsequent appeal, by the Illinois Competitive Energy Association (ICEA) and the Illinois Industrial Energy Consumers (IIEC), is currently pending before the Illinois Supreme Court. Efforts to continue litigation of this matter are ongoing, but are not supported by federal co-funding.

Completion of Front End Engineering Design (FEED)

The FEED was submitted to the DOE on December 13, 2013—on schedule. Over 1,100 individual deliverables were included in the FEED package and provided a solid basis for construction estimating and planning inclusive of:

- Coordinated 3D-CAD models of the power plant islands
- Fully designed large bore and high energy 3D-CAD pipe designs
- Extremely advanced Boiler and AQCS equipment designs – approximately 80% complete

At the time of submittal, the FEED package scored a 330 out of 1,000 (lower is better) on the Construction Industry Institute project development readiness index (PDRI). Such a score indicates an extremely well developed project at the FEED stage, well beyond bid-ready, and nearly construction-ready.

Submission to DOE of a definitive estimate of project cost

The definitive cost estimate of $1.27 billion was delivered on March 31, 2014—on schedule. The capital cost estimate included EPC direct and indirect costs, owner's costs, EPC management reserve (contingency), EPC fees, owner's costs (including financing costs), and owner's management reserve that were anticipated to be sufficient to finance and construct FutureGen 2.0. The estimate fit within the DOE project budget, the ICC pre-approved CAPEX limits, and the Illinois statutory rate caps. Further, the definitive cost estimate:

- Was based on a 65% to 90% complete design – well beyond normal FEED-derived cost estimates.
- Was supported by firm price contracts for all of the primary mechanical components within the process islands.
- Was consistent with commercial pricing for two island-based EPC contract wraps provided by B&W and Air Liquide.
- Included the addition of a steam turbine upgrade to the CAPEX budget (later determined to be unnecessary and resulting in subsequent cost savings).
- Was based on provision of oxygen via a traditional over-the-fence (OTF) financing arrangement.

Issuance of Non-appealable Air and Water Permits

Air and water permits were issued by the Illinois EPA on schedule and are final and effective.

While not a formal appeal, the Sierra Club filed a citizen's suit in the U.S. District Court for the Central District of Illinois arguing that Ameren and the Alliance had failed to obtain a Prevention of Significant Deterioration (PSD) permit in violation of the Clean Air Act. The court dismissed the Sierra Club lawsuit, stating that the case should be heard by the Illinois Pollution Control Board. The Sierra Club filed a challenge with the Illinois Pollution Control Board, which ruled against the Sierra Club on November 6, 2014. The Sierra Club then challenged the Illinois Pollution Control Board decision in a lawsuit filed with the Illinois Fourth District Appellate Court. Efforts to continue litigation of this matter are ongoing, but are not supported by federal co-funding. While not a direct appeal, depending on the type and structure of commercial financing, the litigation causes varying degrees of investor concern. Thus, while the project's legal team is confident in the case ultimately being resolved in the project's favor or settlement being reached, the Sierra Club's action has contributed to delays in achieving financial close and a notice to proceed with full construction.

Execution of Engineering Procurement and Construction (EPC), and Operating & Management (O&M) Contracts

The EPC Contracts were negotiated in nearly all respects at the time of the close-out decision with one first-tier issue remaining to resolve, along with a handful of second-tier issues. The first-tier issue is the ability to secure an adequate guarantee on CO_2 flue gas concentration (CO_2

FGC) – a prerequisite for commercial financing. This open issue on the boiler island EPC contract is a precursor to completing the CO_2 compression and purification island EPC contract. It is a prerequisite to managing the risk of completing the plant on schedule with the performance required to meet the requirements of the PPA and the Clean Coal Portfolio Standard law, which is the statutory framework under which the PPA was approved. There is little to no doubt that the required concentration can be technically achieved; it is a question of the ability to secure an EPC guarantee at a reasonable price.

It is noteworthy that there are several commercial and technical approaches that could be employed together or separately to improve the ability to structure an adequate guarantee on the CO_2 flue gas concentration, but the approaching federal funding expiration deadline and associated closeout decision did not afford the time needed to implement these solutions.

Achieve Financial Close

Financial close (i.e., the final commitment of debt and equity to the project with an associated notice to proceed to full construction) had not been reached at the time of the closeout decision. Three interlinked factors were the drivers: (1) one outstanding appeal related to the PPA and a collateral Sierra Club citizen suit; (2) the outstanding EPC contracts, principally driven by the outstanding CO_2 flue gas concentration issue; and (3) final debt/equity structuring and commitment to fund requires resolution of the first two items. While there is a path to resolve all these matters, it is a path that takes more time than remained prior to the statutory expiration of federal co-funding.

At the time of the closeout decision, the Alliance had negotiated a letter of intent to provide full equity to the Oxy-Combustion Large Scale Test Project contingent upon a final stage of investor due diligence. The equity investors included a major energy company with substantial coal-fired power plant, pipeline, and gas storage operating experience, as well as a best-in-class energy-focused equity investment funds.

1.4 Lessons-Learned

Safety

Successful completion of all early construction efforts with zero recordable safety incidents and no lost time accidents is certainly an important achievement of the FutureGen 2.0 Oxy-Combustion Power Plant Project. The project involved substantial activities for nearly two years to maintain the idled Meredosia power plant in a retrofit-ready condition. Other early construction work, such as installation of a chimney foundation and installation of underground piping was performed. During this work there were zero recordable safety incidents, an achievement also met by the companion CO_2 Pipeline and Storage Project. Demonstrated emphasis on safety during the early stages of the project, while worker and community trust is being built, is critical to long-term success. Safety started with a strong safety culture created by the Alliance and subsequently reinforced with all contractors. As the work progressed, safety priority was further implemented by selecting only contractors who demonstrated an emphasis on safety within their own organizations, and who achieved strong safety performance in their prior projects. All Alliance contracts were awarded with contractor safety performance as a primary selection criterion.

Technology Integration

Projects of this complexity require that substantial attention be paid to the integration of the technologies. The design must take into account that the connected technology will have to start up and shut down safely, and will have to operate, at times, in upset conditions or in a fouled or otherwise degraded state.

Technology Guarantees

Demonstration of near-zero emissions power generation technology at commercial-scale quickly becomes a billion-dollar plus enterprise. At this scale of resources, substantial private capital is required beyond what government resources may be available. In the power sector, returns (particularly when regulated) are not sufficient to justify high risk investment. Therefore, early identification of required guarantees from technology providers and the associated financial penalties for non-performance should be prioritized as early as possible in the project development process and factored into contractor and technology provider selection.

Market Conditions and Contracting

With regard to EPC and operating contracts, it is important to recognize market conditions when developing contract requirements, and to find win-win strategies when in some cases only one or two viable service providers are available and qualified. These objectives were very successfully achieved by the FutureGen 2.0 contract development team in most instances, as evidenced by the high percentage of competitive firm pricing content obtained, while also maximizing joint owner/contractor incentives to meet or beat the budget for content that was not practical to firm price. Most significantly, stressing safety performance and safety planning as a critically important contractor selection criterion was almost certainly a contributing factor to the project's outstanding safety record, and had the added benefit of aligning the project with contractors who possess the coincident traits of strong organization and planning capabilities.

2.0 INTRODUCTION AND PROJECT DESCRIPTION

2.1 Project Description

The Department of Energy's FutureGen 2.0 Program has made step-change improvements to clean coal and carbon capture and storage (CCS) technology. The program involved two projects: (1) the Oxy-Combustion Large Scale Test Project and (2) the CO_2 Pipeline and Storage Project. The Oxy-Combustion Large Scale Test Project focused on the design, construction, and subsequent commercial operation of a first-of-a-kind, near-zero emissions, coal-fueled power plant. To support these objectives, the FutureGen Industrial Alliance (Alliance) was to permit, construct, operate, and test an advanced oxy-combustion power generation plant at the Meredosia Energy Center. The project was focused on repowering the Meredosia Unit 4 steam turbine generator, capturing most of its CO_2 for subsequent transport and storage in a linked downstream portion of the program, undertaken separately by the Alliance. The Alliance executed a Cooperative Agreement with the Department of Energy (DOE) for a federal cost share of approximately $590 million of the project. The Alliance worked with Air Liquide Process and Construction, Inc. (ALPC) and Babcock & Wilcox Power Generation Group (B&W PGG) on the engineering design, and contracted URS Corporation (now AECOM, Inc.) as owner's engineer for project permitting support and other engineering services. Ameren Energy Resources (now Ameren Medina Valley Cogen, LLC) maintained the existing, idled Meredosia facility as well as supporting permitting activities.

The repowered plant was designed for an expected 30-year life with respect to operability, maintainability and reliability. It was designed to utilize as much of the existing Unit 4 equipment and systems as possible, with the exception of the boiler, which was to be demolished and replaced with an oxy-combustion boiler, while also using coal-based infrastructure from Units 1, 2, and 3, and the plant's common facilities. Due to the limited operating hours accumulated on Unit 4 since its construction in 1975, much of the existing equipment was determined to be reusable.

2.2 Project Schedule

The Oxy-Combustion Power Plant Project was divided into four phases over time, as follows. See Section 5.3 for a detailed discussion of the schedule development.

Phase I: (October 1, 2010 – October 31, 2012) Pre-Front End Engineering Design (pre-FEED) work necessary to establish the initial plant performance, component sizes, preliminary specifications, and preliminary cost estimate, along with initiation of project permitting and NEPA processes.

Phase II: (June 1, 2013 – August 2015) Completion of final FEED and the majority of detailed design; NEPA process; and all major environmental permits needed for construction, including the Clean Air Act construction permit, along with a definitive project cost estimate.

Phase III: (August 2015 – November 2018) Completion of required construction permitting, the remainder of 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 IV: (November 2018 – June 2019) project testing, data collection, securing the final Clean Air Act operating permit, and performance reporting.

2.3 Project Scope – Division of Responsibility

In Phase II, design work was divided into the following engineering procurement, construction, startup and commissioning islands:

- B&W-PGG
  - Boiler
  - Gas Quality Control System (GQCS) and
  - Balance of Plant (BOP)
- ALPC
  - Air Separation Unit (ASU)
  - CO_2 Compression & Purification Unit (CPU)
- Alliance/URS
  - Existing Facilities (Legacy Plant)

A Mechanical Interface List was developed to define the process streams and utilities and services that cross between power plant process islands. These process streams and utilities were to be supplied to and from a single location at or within the battery limits of each island, with distribution of those utilities beyond the interconnect location within each island by the individual island suppliers. This list was a dynamic list, changing as more detailed information was developed during Phase II.

The Alliance was to own the repowered plant and was to operate and maintain all systems within it. An over-the-fence (OTF) commercial arrangement was to be executed for the ASU, whereby the ASU was to be owned, operated, and maintained, in coordination with the other islands, solely by AL under a services contract developed between the Alliance and Air Liquide Large Industries US (ALLIUS).

2.4 General Project Requirements and Design Philosophy

Conventional coal-fired boilers combust coal in the presence of air. An oxy-combustion boiler combusts coal with a mixture of recycled CO_2-rich flue gas and nearly pure oxygen. By utilizing oxidant that is primarily a mixture of oxygen and CO_2, rather than air which is primarily oxygen and nitrogen, the post-combustion gas (flue gas) is primarily CO_2, and nearly devoid of nitrogen. Elimination of nitrogen in the flue gas significantly reduces the volume and mass of the flue gas which needs to be exhausted and facilitates the capture of high purity CO_2 from the flue gas for subsequent transport and storage.

To support continuous operation of the oxy-combustion boiler, oxygen (O_2) is supplied by an ASU. Compression and purification of the relatively pure post-combustion flue gas is achieved by the CPU. The CPU purifies the captured flue gas for transportation and storage.

Plant design was based on achieving successful oxy-combustion operation within the project budget and schedule constraints. Among the overall project design objectives were:

- Minimum approximate gross electrical output of 168MWe.
- Target minimum CO_2 capture percentage of 70% on a plant-wide annual average basis (allowing for startups, shutdowns, and operation in air-fired mode).
- Target minimum CO_2 capture percentage of 90% on a steady state basis while operating in oxy-combustion mode.
- Target minimum CO_2 annual capture rate (based on 85% capacity factor) of 1.1 million metric tons.
- Minimum Illinois bituminous coal use of 51% of total fuel mix (the final design fuel blend was 60% bituminous).

The boiler capacity and configuration was set to optimize performance for the oxy-combustion operation mode, given the existing subcritical steam cycle. It should be noted that, by reusing the existing subcritical cycle and reducing the plant capacity to something less than the original cycle design capacity of approximately 200 MW gross, the baseline heat rate, prior to oxy-combustion, would have been higher than a typical new conventional plant and would, therefore, constrain the oxy-combustion cycle performance that could otherwise be achieved with a newer plant.

The ASU and CPU were each designed with a single 100% capacity train, sized to accommodate 100% boiler Maximum Continuous Rating (MCR) load at peak summer design temperatures. The engineering and design of the project integrated each of the process islands to provide for fully integrated systems, such that their function, operation, safety and performance would have been well coordinated and not impaired.

2.5 Oxy-combustion Process Description

Figure 2-1 shows the oxy-combustion process schematic for the FutureGen 2.0 Project. The combustion process employs the B&W PGG-ALPC cool recycle process firing a mixture of high sulfur bituminous coal and low sulfur sub-bituminous coal. The system was optimized within the constraints of the budget and reutilization of the existing steam cycle and equipment. Waste heat from the ASU is incorporated into the condensate cycle, while waste heat from the steam cycle is used for flue gas reheating and other process heat loads. Because the project involved repowering an existing steam turbine, turbine design limits restricted the amount of heat that could 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 could not be achieved for this project.

In the cool recycle process, hot gas leaves the boiler and passes through a regenerative advanced quad-sector secondary and primary recycle heater (air heater). This recycle heater is internally arranged to prevent any leakage of the oxidant from the ASU into the flue gas stream to the stack or CPU.

Following the air heater, the flue gas passes through a Circulating Dry Scrubber (CDS) where most of the SO_2 and SO_3 is removed, and then into the Pulse Jet Fabric Filter (PJFF) where particulate matter is removed. From the PJFF the flue gas pressure is boosted by the Induced Draft (ID) fan and the flue gas flow splits. A continuous recirculation stream is sent back to the inlet of the CDS to ensure a minimum allowable gas velocity through the CDS absorber for all boiler loads. After this recirculation stream takeoff, the gas stream splits once again. One stream from this split is boosted by the Secondary Recycle (SR) fan and then passes through a gas reheater to avoid downstream moisture condensation at low loads. Oxidant (nearly pure oxygen) is introduced into the secondary recycle flow after the SR fan via Floxynators™ (proprietary oxygen dispersion injectors) before re-entering the recycle heater for heating prior to the boiler wind box. The SR fan controls the secondary flow to the boiler. The remaining flue gas stream passes through a Direct Contact Cooler Polishing Scrubber (DCCPS) where moisture is reduced and additional SO_2 and particulate matter is removed.

Saturated gas leaving the DCCPS is reheated to avoid downstream moisture condensation and is again split with one stream flowing to the CPU, and the other stream supplying the Primary Recycle (PR) fan. The PR fan provides the flow required to dry and convey the pulverized coal to the burners. Oxidant is introduced into the primary recycle flow after the recycle heater via Floxynators™. 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 primary and secondary recycle and CPU streams are isolated by dampers and all of the gas leaving the ID Fan flows to the stack as in a conventional air-fired design. The primary and secondary recycle dampers are closed and 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.

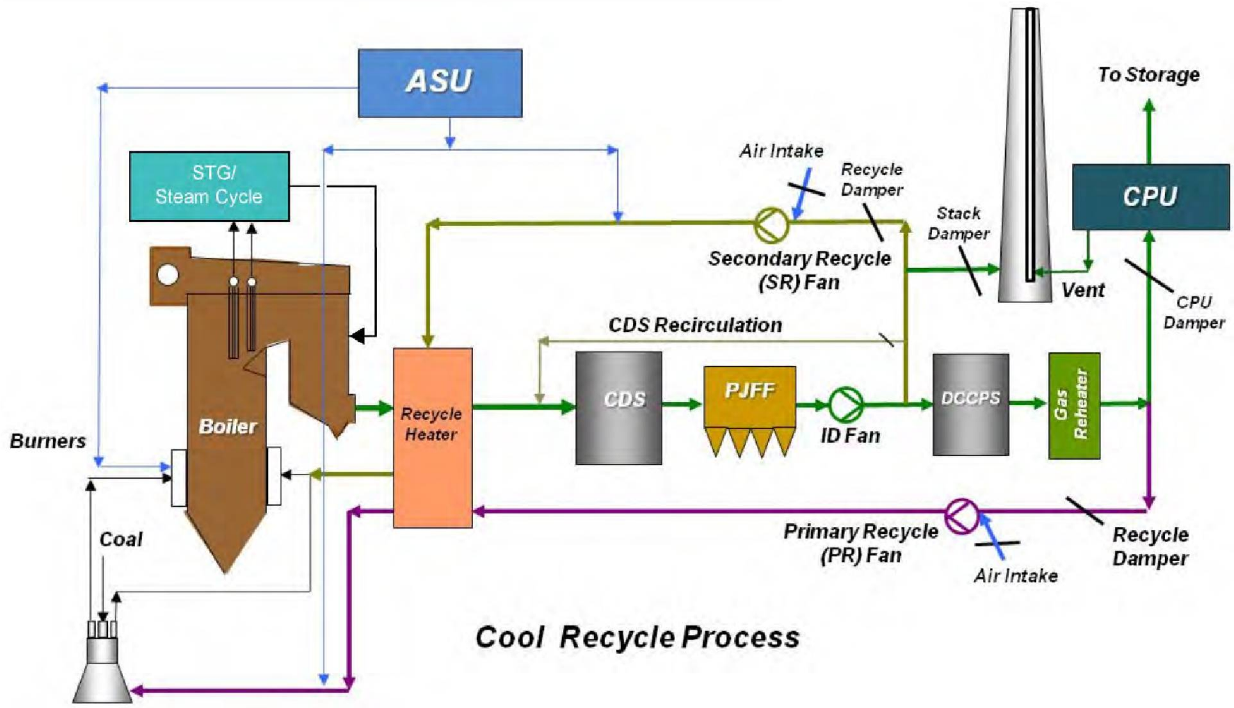


Figure 2-1: Oxy-combustion Cool Recycle Process Schematic

3.0 Project Design

This section describes the preliminary design and performance of the project as established during Phase II.

3.1 Plant Performance

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

- Ambient Dry Bulb Temperature: 11.7 ºC (53 ºF)
- Ambient Wet Bulb Temperature: 8.9 ºC (48 ºF)
- Full load operation of all islands, based on the following criteria:
    - Oxy-combustion operation of boiler at maximum continuous rating on 100% design fuel (60% Illinois No. 6 bituminous coal, 40% PRB sub-bituminous coal, typical analyses), with 1% boiler drum blowdown.
    - Steam turbine at throttle conditions of approximately 1,950 psig and 1,000º F, with steam flow corresponding to approximately 168 MWe gross turbine output.
    - ASU at 100% load, normal operating mode
    - CPU at 100% load, normal operating mode, 98% CO_2 capture rate, discharging to the CO_2 pipeline, resulting in an annual capture of 1.08 million metric tons (MMT) per year of CO_2, based on a plant capacity factor of 85%.
    - All heat integration between islands operating normally, per the conditions established in the Project Design Basis Document.

Overall plant performance is presented in Table 3-1, based on both expected boiler performance as well as on the latest agreed upon boiler performance guarantees. Based on an evaluation of the limited Unit 4 performance data available, the expected performance figures include an estimated 3.1% degradation from new and clean turbine performance reported on the original turbine heat balances. The stated expected performance is as projected for oxy-combustion repowering of an older plant with a relatively small subcritical steam cycle, and any meaningful comparison of the results for this first-of-a-kind plant must consider the underlying technical aspects unique to this project. When all factors are considered, the expected performance results presented here are consistent with project expectations and objectives.

Table 3-1: Overall Plant Thermal Performance

Boiler Performance Basis	***Expected***	***Guaranteed***
Steam Turbine Generator Output (gross)	167,622 kW	160,150 kW
Generator Step-Up Transformer Losses	674 kW	644 kW
Steam Turbine Gross Generation to 138 kV Grid	166,948 kW	159,506 kW
Plant Auxiliary Power		
Boiler	5,776 kW	
GQCS	1,162 kW	
ASU	27,246 kW	
CPU	21,492 kW	
BOP New	5,600 kW	
BOP (Legacy – Existing)	7,103 kW	
Aux Transformers	275 kW	
Total Plant Auxiliary Power	68,654 kW	69,509 kW
Plant Net Generation	**98,294 kW**	**89,997 kW**
Boiler Heat Output	1,450.7 GJ/hr (1,375.0 MMBtu/hr)	1,400.6 GJ/hr (1,327.5 MMBtu/hr)
Boiler Fuel Efficiency (HHV)	87.04 %	86.80 %
Fuel Heat Input (HHV)	1,666.7 GJ/hr (1,579.7 MMBtu/hr)	1,613.6 GJ/hr (1,529.4 MMBtu/hr)
Coal Consumption	72,870 kg/hr (160,640 lb/hr)	70,545 kg/hr (155,525 lb/hr)
Plant Net Heat Rate, HHV	**16,956 kJ/kWh (16,071 Btu/kWh)**	**17,930 kJ/kWh (16,994 Btu/kWh)**
Net Plant Efficiency, HHV	**21.2%**	**20.1%**

3.1.1 Plant Power Consumption Changes from Phase I

Although auxiliary power was identified as part of the Phase I opportunity assessment for potential Phase II performance improvements, the total plant auxiliary load for Phase II decreased only slightly from Phase I. While there was a reduction in auxiliary load for the ASU, CPU, Boiler and GQCS islands, this reduction was offset by increased BOP loads, as further described below.

3.1.1.1 ASU and CPU

During Phase II AL considered the following possible power saving scenarios:

- Continuing process optimization studies to further improve energy efficiency (this would potentially involve some additional investment)
- Working with B&W PGG to optimize the split of the MP and LP O_2 flowrates
- Heat recovery of the LOx purge refrigeration loss by means of an efficient heat exchange
- Optimization of membrane energy requirements (to be confirmed via physical testing), with expected improvement (up to 10 kWh/metric ton) in predicted performance

Due to the effort in Phase II, the auxiliary power consumption was reduced by 810 kW.

3.1.1.2 Balance of Plant (BOP)

Phase I BOP new equipment auxiliary loads were based on budgetary equipment estimates. The cooling tower loads increased during Phase II when final heat exchanger heat duties and all cooling water flow requirements were finalized.

The water treatment area was sized on preliminary permitting requirements. In Phase II, with the final permit requirements, the water treatment area doubled in size and equipment requirements, thereby increasing the auxiliary loads.

The BOP auxiliary loads effectively increased by 1,306 kW from Phase I estimated loads to Phase II engineered loads. This increase excludes any changes due to load accounting transfers between islands (i.e. Phase I Boiler and GQCS Island loads that were moved to the BOP Island for Phase II).

3.1.1.3 Boiler and Auxiliaries (includes GQCS)

At the end of Phase I it was reported that options would be pursued in Phase II that could result in a reduction in auxiliary power. The key items were:

- work with the recycle heater vendors to reduce internal leakage
- work with the selected fan vendor(s) to reduce fan auxiliary power
- optimize flue design and arrangement as well as equipment design to reduce pressure losses which will decrease the pressure rise required by the fans
- refine the auxiliary power prediction for the GQCS

As a result of Phase II, the expected auxiliary power consumption for the Boiler and GQCS islands was reduced by approximately 563 kW (based on typical ambient conditions and typical blend fuel) compared to the Phase I values and exclusive of any load accounting transfers.

For the boiler island, most of the reduction came from the induced draft and primary recycle fans, mostly due to fan efficiency data that was not available in Phase I and higher than the Phase I estimated efficiencies. In addition, refinement of the Phase II flue and duct arrangement resulted in a lower pressure drop throughout the system.

For the GQCS island, significant power savings came from the change in Phase II from a pebble lime reagent system to hydrated lime reagent for the CDS. This enabled the removal of several pairs of lime conveying blowers, the lime hydrator and associated equipment. Firming up the design of the DCCPS piping in Phase II resulted in some additional power savings as the pumps in the DCCPS area are relatively large power users.

3.1.2 Plant Performance Basis and Benchmark Comparison

Because the existing Meredosia plant is a relatively small commercial scale and employs a subcritical steam cycle, turbine cycle and corresponding baseline air-fired plant efficiencies are expected to be significantly lower than those for a typical more modern Rankine cycle plant. As a comparison, using the original Meredosia Unit 4 turbine cycle heat rate, but assuming a typical boiler efficiency (87%) and auxiliary load (10-11% of gross power generated) for a similar size, coal-fueled, air-fired plant of the same vintage with all required environmental equipment, expected net plant efficiency would be around 33.5% new and clean.

Typical large modern air-fired ultra-supercritical plants, such as American Electric Power's Turk plant, employing main steam pressure exceeding 3,500 psia and steam temperatures of 1,100 ºF, can be expected to achieve net plant efficiencies on the order of 38% to 40%, depending on fuel, site conditions, and cooling system design. Most of the 4.5 to 6.5 percentage point difference between the comparable Meredosia new and clean efficiency of 33.5% and a new modern greenfield ultra-supercritical plant can be attributed to the difference in steam conditions, with the rest being due to plant size disparity and the impacts of new modern equipment design efficiencies compared to 30 year old equipment designs.

Recent studies have reported estimated efficiencies for new modern bituminous coal-fired supercritical/ultrasupercritical oxy-combustion plants from 29% (cold recycle) to 33.6% (warm recycle)[1], and around 31.5% (warm recycle)[2] for a similar coal-fired plant using PRB coal. While the current predicted efficiency for FutureGen 2.0 is only 21.2%, any direct comparison to the higher efficiencies in these recent studies is not equitable due to the differences between the existing Meredosia unit and a typical modern plant. A more equitable comparison can be made by evaluating efficiencies for the same plant both with and without oxy-combustion or other CCS technology employed.

To make such a comparison for Meredosia, the aforementioned equivalent new and clean plant efficiency of 33.5% should also be corrected for existing Unit 4 steam turbine performance degradation over the past 30 years, since this degradation has been included in the stated oxy-combustion performance. Steam turbine degradation has been estimated at 3.1%, which

[1] DOE/NETL-2007/1291 "Pulverized Coal Oxycombustion Power Plants", J. Ciferno, et al. August 2007.
[2] EPRI Report 1021782 "Engineering and Economic Evaluation of Oxy-Fired 1100F Ultra-Supercritical Pulverized Coal Power Plant with CO_2 Capture; Final Report", D. Thimsen et al. July 2011.

translates to a 1% reduction in net plant efficiency. This results in a comparable baseline plant efficiency of approximately 32.5% for a coal-fueled, air-fired version of the Meredosia Unit 4 plant. Comparing this baseline efficiency to the estimated FutureGen 2.0 efficiency of 21.2% indicates an efficiency loss of slightly more than 11 percentage points due to oxy-combustion. For reference, recent study estimates for oxy-combustion plants firing bituminous coal showed about a 10 percentage point loss in efficiency[1,3] for oxy-combustion compared to a similar air-fired plant (due primarily to the large auxiliary power requirements for the ASU and CPU). Lower oxy-combustion efficiency penalties, as low as about 6-7 percentage points, have been reported[1,2], but these results are for oxy-combustion cycles that employ warm recycle, deep heat integration including flue gas cooling after the recycle heater, and oxidant preheating, none of which have been included in the FutureGen 2.0 design because of either project cost or technical limitations.

It therefore appears that the predicted FutureGen 2.0 oxy-combustion penalty is only slightly higher (1-1.5 percentage points) than what other recent studies have indicated. The small additional penalty is likely the result of other unique aspects for the FutureGen 2.0 project not accounted for in the above discussion, including:

- The CPU has been designed for a steady-state CO_2 feed concentration of approximately 90%, yielding a CO_2 capture rate in the CPU of 98%, vs. the typical 90% capture rate used as the basis for the above referenced comparative studies
- Due to project capital cost limitations, comparatively low efficiency ASU and CPU designs were selected
- The CPU design includes an oxidation catalyst to significantly reduce CO emissions
- Because of project capital cost limitations, the selected plant gross capacity of 167.6 MWe results in the existing BOP portion of the plant being operated at a less efficient part load condition

3.2 Plant Effluents and Emissions

3.2.1 Air Emissions

Table 3-2 summarizes air emission limits for the oxy-combustion boiler, and Table 3-3 summarizes air emission limits for the auxiliary boiler as listed in the issued air construction permit, as well as the applicable state and federal standards as referenced in Section 4 of the construction permit application. Emissions of criteria pollutants (CO, SO_2, NOx, PM, VOM, Hg) were expected to be significantly lower than what would be expected from a new, conventional, coal-fired plant.

[3] CRS Report for Congress R41325 "Carbon Capture: A Technology Assessment", P. Folger. Coordinator, July 2010

Table 3-2: Project Air Emissions (Oxy-combustion Boiler)

Emissions Constituent	Construction Air Permit Limits		Applicable Illinois State Standards	Applicable Federal Standards	
	lb/hr[1]	Tons/Year		40 CFR 60 Da	40 CFR 63 UUUUU
CO	110	281.2	200 ppm@ 50% excess air (air fire only)	1.1 lb/MWhr (gross); or 1.2 lb/MWhr (net)[4]	-
NO_x	--[2]	1,691.7	0.25 lb/MMBtu (ozone season average)	0.70 lb/MWhr (gross); or 0.76 lb/MWhr (net)	-
VOM	2.65	9.9	-	-	-
PM Filterable	7.45	27.8	0.10 lb/MMBtu	-	0.090 Lb/MWhr (gross)
PM-Total	-	-	-	0.090 lb/MWhr (gross); or 0.097 lb/MWhr (net)	-
SO_2	--[2]	196.4	1.2 lb/MMBtu	1.0 lb/MWhr (gross); or 1.2 lb/MWhr (net); or 97 % reduction	1.0 lb/MWhr
Hg	-	-	0.0080 lb/GWh gross or 90% control	-	0.0030 lb/GWh
Pb	0.034	0.15	-	-	-
Fluorides	0.63	1.6	-	-	-
Sulfuric Acid Mist	1.70/2.97[c]	10.5	-	-	-
CO_2	--[2]	1,448,759[3]	-	-	-

[1]Limits apply as three-hour averages
[2]Limits not set because continuous monitoring is required for this pollutant
[3]A more restricted limit, requiring a 70% reduction in CO_2 emissions, is a statutory requirement of the Illinois Clean Coal Portfolio Standard
[4] NOx/CO alternative to NOx standard

Table 3-3: Project Air Emissions (Auxiliary Boiler)

Emissions Constituent	Construction Air Permit Limits		Applicable Illinois State Standards	Applicable Federal Standards	
	lb/hr[1]	Tons/Year		40 CFR 60 Dc	40 CFR 63 JJJJJJ
CO	3.5	41.6	200 ppm@ 50% excess air	-	-
NO_x	--	--	-	-	-
VOM	0.4	1.66	-	-	-
PM Filterable	2.9	12.5	0.1 lb/MMBtu	0.03 lb/MMBtu or Fuel Sulfur < 0.5% by weight	-
PM-Total	-	-	-	-	-
SO_2	-	0.62	0.3 lb/MMBtu	Fuel Sulfur < 0.5% by weight Or SO_2 < 0.5 lb/MMBtu	-
Hg	-	-	-	-	-
Pb	-	-	-	-	-
Fluorides	-	-	-	-	-
Sulfuric Acid Mist	-	0.0124	-	-	-
CO_2	-	-	-	-	-

[1]Limits apply as three-hour averages
[2]NESHAP for oil fired industrial boilers at area sources does not include numerical limits.

3.2.2 Liquid and Solid Effluents

The major project effluents at average annual operating conditions are summarized in Table 3-4.

Table 3-4: Project Effluents

Solid Effluents	**Effluent Rate**
Bottom Ash (dry)	1,179 kg/hr; 28.30 tonnes/day (2,600 lb/hr; 31.2 tpd)
Fly Ash (dry, incl. CDS reaction products)	15,831 kg/hr; 379.93 tonnes/day (34,900 lb/hr; 418.80 tpd)
Water/Wastewater Treatment Solids	16.2 m^3/day 24 yd^3/day
Liquid Effluents (refer also to Water Balance)	**Effluent Rate**
Cooling Water	34 Ml/day (9.0 MGD)
Process Wastewater	1.35 Ml/day (0.357 MGD)
Intake Screen Backwash	1.01 Ml/day (0.266 MGD)
Sanitary Sewage	12.3 lpm; 17.7 m^3/day (3.25 gpm; 4.68 kgal/day)

3.2.3 CO_2 Recovery, Production, and Quality

During full load steady state design oxy-combustion 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 3-5.

Table 3-5: CO_2 Recovery, Production, and Quality

CO_2 Recovery (mass basis)	98%(of the CO_2 entering the CPU)
Mass flow (CO_2)	144,700 kg/hr (319 klbs/hr) 3,473 tonnes per day (3,828 tpd) 1.08 million metric tons/year (based on 85% capacity factor)
Pressure	145 barg (2,100 psig) *
Temperature	21.7 °C (71°F)
CO_2 content	99.8% (by mass, dry basis)
Inerts (Ar, N_2)	≤ 0.04% (by mass, dry basis)
Water (H_2O)	≤ 1 ppmw
Oxygen (O_2)	≤ 20 ppmw (dry basis)

Total Sulfur (SO_x)	≤ 1 ppmw (dry basis)
Hydrogen Sulfide (H_2S)	Negligible
Nitrous Oxides (NO_x)	≤ 1,200 ppmw (dry basis)
Mercury (Hg)	≤ 1 ppbw (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 II.

3.2.4 Major Plant Consumables

Major plant consumables at average annual operating conditions are summarized in Table 3-6.

Table 3-6: Oxy-PC Plant Consumables

Consumable	Consumption Rate
Boiler/GQCS Consumables	
Fuel (Coal)	72,870 kg/hr (160.6 klb/hr) 1,748.9 tonnes/day (1,927.8 tpd)
Illinois Bituminous Coal	43,720 kg/hr (96.4 klb/hr) 1,049.3 tonnes/day (1,156.6 tpd)
Powder River Basin Coal	29,150 kg/hr (64.3 klb/hr) 699.6 tonnes/day (771.1 tpd)
Lime	6758.6 kg/hr (14.9 klb//hr) 162.2 tonnes/day (178.8 tpd)
Trona	113.4 kg/hr (250 lb/hr) 2.7 tonnes/day (3.0 tpd)
Water (refer also to Water Balance)	
River Water Intake	48.7 Ml/day (12.9 MGD)
River Water Consumption	13.3 Ml/day (3.5 MGD)
City Water	16.3 kl/day (4.3 kgal/day)
Demin Water	253 kl/day (67 kgal/day)(50 gpm)
Total Water Consumption	13.3 Ml/day (3.5 MGD)

3.3 Plant Control

3.3.1 Oxy-PC Plant Considerations

Control of an oxy-combustion plant, though very similar to a conventional air-fired plant, would have required some significant additional considerations. The steam cycle and balance of plant were essentially the same as with air firing, though additional systems, such as the cooling tower integrated with the DCCPS, were required (see Figure 3-1). There were only minor differences in the boiler. To avoid air infiltration, the boiler was to be operated slightly pressurized on the gas side, and due to the difference in heat transfer properties of the flue gas, the furnace was to be slightly shorter than with air firing. The oxy-combustion boiler was to be followed by a GQCS that would have prepared the flue gas for the CPU rather than controlling air emissions as in a conventional Air Quality Control System (AQCS) used with air firing. The GQCS and AQCS would have had the same equipment; a circulating dry scrubber (CDS) and a pulse jet fabric filter (PJFF). These would have performed the same functions of removing particulate, SOx, acid gases, and heavy metals like Hg, As and Se.

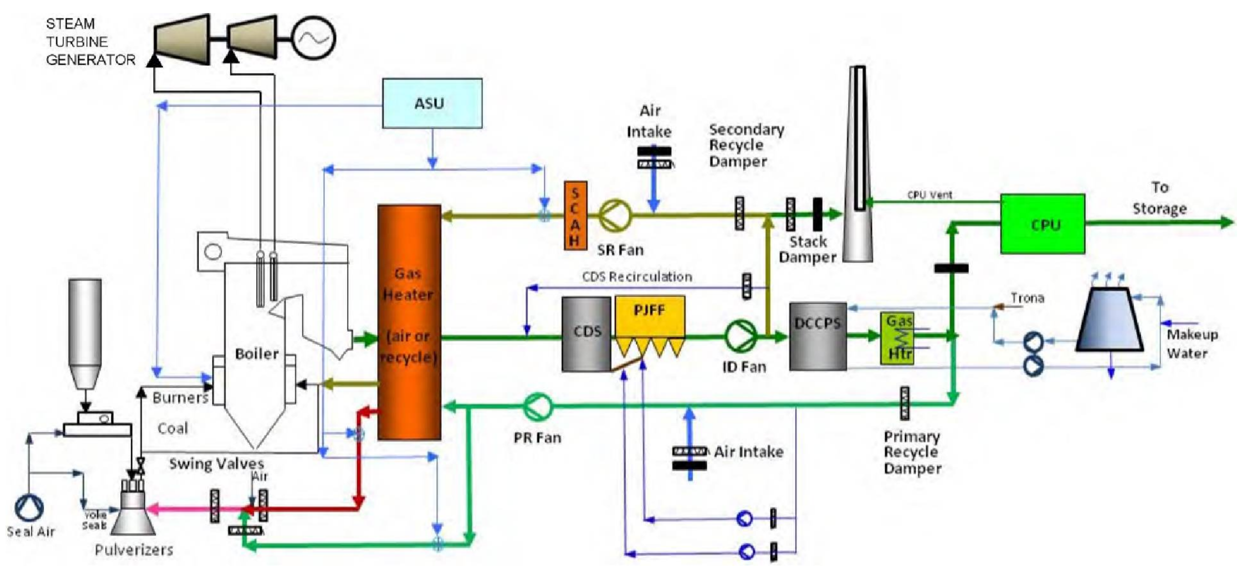


Figure 3-1: Oxy-combustion Plant Process Schematic

The flue gas composition leaving the boiler in oxy-combustion would have been much different, containing about 65% CO_2 and 26% water by volume compared to 14% CO_2 and 12% water with air firing. Due to the higher water content entering the CDS-PJFF, the adiabatic saturation temperature in oxy-combustion would have been slightly higher than with air firing, so the water content and temperature of the flue gas leaving the CDS would also have been somewhat higher than with air firing. To reduce flow and power consumption in the CPU and PR fan and to provide a drier primary recycle flow to the pulverizers, a DCCPS was to be provided. The DCCPS process would have utilized a wet cooling tower design to provide the necessary heat rejection. The moisture condensed from the flue gas in the cooling process would have made up for the water consumed in the DCCPS tower due to evaporation, thus minimizing overall makeup water needs and avoiding the need to treat significant amounts of condensate. Since the gas leaving the DCCPS would have been saturated, it would also have been reheated to avoid condensation in the downstream flues. During the cooling process, some trona (sodium sesquicarbonate) would have been added to the cooling water to further reduce the flue gas SO_2 level to around 1-2 ppm to minimize corrosive conditions in the CPU.

In addition to significant differences in flue gas composition, the flue gas flow at full load would also have been much lower in quantity than with air firing (about one-third as much mass flow) due to the elimination of nitrogen from the combustion process.

The unit would have started up in air firing mode just as a conventional plant would, but then would have transitioned to oxy-firing at a low load. Flue gas was to be recycled to the boiler to make up for the mass of nitrogen that would have been present in air firing, and oxidant provided by the ASU was to be injected in four locations; to the burners, downstream of the SR fan, and downstream of the PR fan in the hot and tempering streams. The oxidant (the oxygen plus small amounts of argon and nitrogen) could have been controlled separately from the recycled flue gas, where with air-firing the oxygen content in air was to be fixed. Unlike air-firing, where separate control of these parameters was not possible, oxy-firing allows more flexibility in controlling where and how much oxygen was to be added in the process to optimize combustion. Independent control of the secondary recycle flue gas flow (the primary recycle gas flow would have been dictated by the pulverizer demand) also would have allowed freedom to adjust the mass flow to the boiler to control reheater outlet temperature, thereby minimizing spray attemperation and the consequent efficiency loss.

Since the unit would have started up on air firing and would have transitioned to oxy-firing, the boiler was to be capable of maintaining a controlled steam generation rate based on gas side measurements with two different working fluids – air for air-firing and recycled flue gas and oxidant for oxy-firing. Therefore, normal volumetric measurements were not sufficient for boiler control. Volumetric flows would instead have been measured and then converted to mass flows to provide a consistent control parameter regardless of firing mode. Volumetric air flow was to be measured at the fan air intakes; recycle gas flows were to be measured upstream of the PR and SR fans; and oxidant was to be measured at the outlet of the ASU. Using the known mole weights and temperatures of the various fluids, the measured volumetric flows were to be converted to mass flows to compare with the boiler mass flow set point. This control complication would have been an additional requirement for oxy-combustion that would not have been necessary with air firing.

The following sections describe the control of the various major systems during startup, load changing, shutdown, and under major trip conditions.

3.3.2 Dynamic Modeling

3.3.2.1 Plant Operation Overview

Since there is no operating experience for a fully integrated, commercial scale, oxy-combustion power plant, it was important to understand the physical dynamics of the plant, especially the aspects that differ from conventional air-fired plants. Unlike conventional air-fired, pulverized coal power plants that operate with an open, once-through gas path from fan inlet to the stack, the plant was to operate as a closed system in oxy-combustion mode. Flue gas was to be recycled to the boiler and, except during startup and transition, the flue gas produced by oxy-combustion, was to be routed to the CPU, where CO_2 was to be purified and compressed for pipeline transfer and deep geologic storage. Because the CPU incorporates a very large compressor, if not properly controlled, the CPU can adversely impact the boiler/GQCS process. To address this concern and to ensure safety and operability, an engineering-grade dynamic model of the plant was developed to evaluate how operational changes, trips, and transients might have impacted plant operation.

Since the gas path was to be closed and the CPU would have influenced the gas-side dynamics in the boiler/GQCS process, it was necessary to obtain accurate gas-side pressure transients in order to verify that continuous and transient design gas pressures in equipment, and flues, and ducts were not exceeded during various trip and operating conditions. Other scenarios were also investigated to establish the validity of design parameters. Study of additional cases to support safety investigations, were planned for Phase III. To ensure the model accurately captured the correct gas-side pressure, temperature, and flow responses, a high level of fidelity was incorporated. The model fidelity includes: non-approximated thermodynamic equations (fundamental physics), sufficient nodal resolution at all locations, fine resolution of certain physical components, and detailed controls. The dynamic model was sophisticated and exceeds the fidelity typically found in a plant simulator for operator training. The component characteristics were also modeled to match the final equipment characteristics to as great an extent as practical based on the vendor supplied information and other available information. In addition, the control philosophies for major trips (MFT, CPU trip, Pulverizer trip), and some transients were preliminarily evaluated. Once the model was fully tuned in Phase III, a variety of operating scenarios such as transition and pulverizer start, and the major and some minor trips were to have been evaluated. Eventually, in the advanced stages of Phase III, this model was to become the engine for the operator training simulator.

3.3.2.2 Model Description

The Dynamic Model was run in two modes; Worst-Case Modeling and Nominal Modeling. The Worst-Case Model was built first and then evolved into the Nominal Model. The Worst-Case Modeling effort was completed August 2013 and the Nominal Model continued to be developed until the closeout decision. Both models include the boiler gas and steam systems and the GQCS. B&W data from previous projects was used to build these systems during the initial modeling effort. Feedwater inlet and steam outlet to the turbine, the ASU, and the CPU were simulated as boundary conditions in the initial worst-case model. In parallel, AL developed a CPU model which has now been incorporated into the Nominal Model. The ASU model was to have been added as the simulator evolved into the Operator Trainer. Other data such as the turbine, feedwater system, and balance of plant systems had not yet been incorporated. The Nominal Model was to have continued to be refined as vendor information, including component control data such as fan stall characteristics and complete BMS control logic, was obtained during Phase III.

The Dynamic Model was built using GSE software. A schematic, depicting how the B&W-GSE process model communicates with the AL and B&W models, is illustrated in Figure 3-2. Although boundary conditions were used in place of the AL models for the Worst-Case modeling, the communication shown in Figure 3-2 was expected to be used in Phase III work, except that the AL models would have needed to physically reside close to the B&W models in order to achieve real-time simulation. Note that the connection between the B&W-GSE process model and the AL model is shown in the diagram. The AL CPU model for their engineering studies was built in HYSYS. Typical variables transferred between the models included gas flow rates, temperature, pressure, etc.

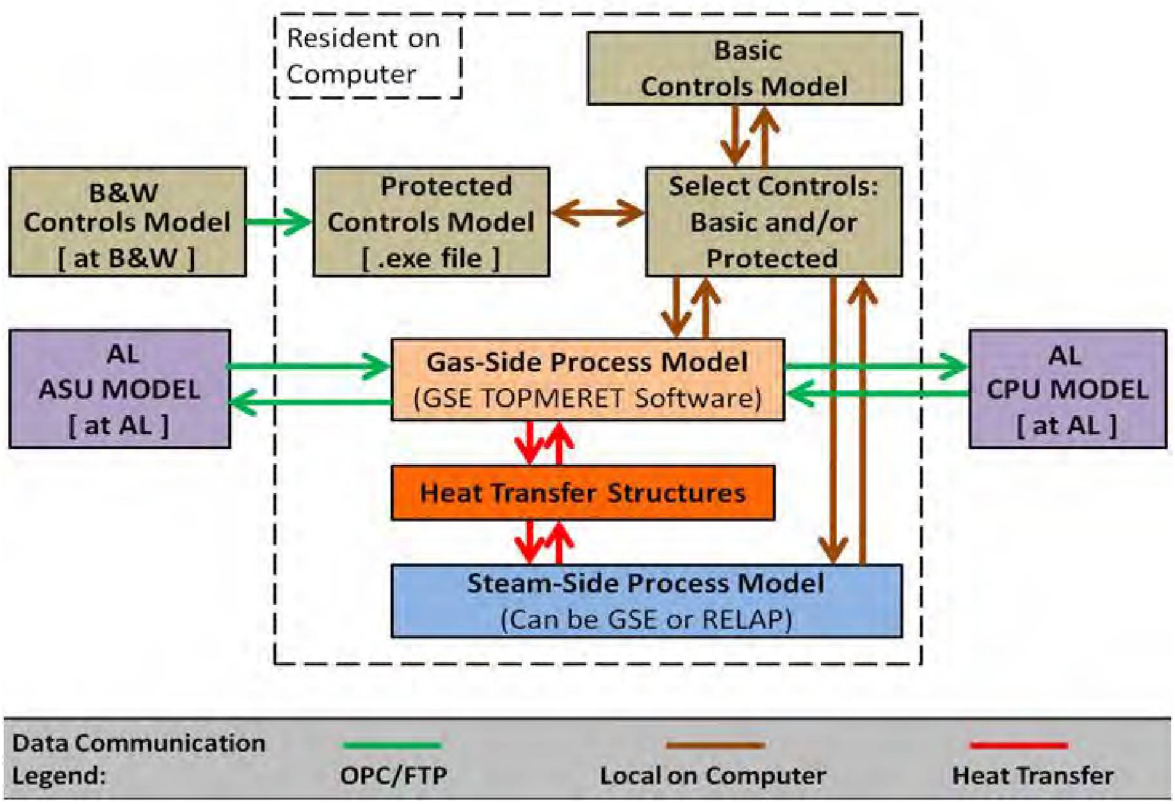


Figure 3-2: Communication between the B&W-GSE and AL Models

At the point where work was halted, the CPU model communicated with the boiler model over a secure VPN connection between the AL network and the GSE network. The two models were synchronized using a heartbeat transmission and the models each took time steps of 1/40th of a second. The boiler model set the boundary flows and the CPU model set the boundary pressure. This model integration scheme would have provided accurate results and would have allowed the two models to be physically separated during development.

3.3.2.3 Preliminary Results

Two trips were identified as needing evaluation during Phase II to confirm design assumptions. In order of priority, first was a CPU trip and the second was a single pulverizer trip. For both, the primary question was how much time would be available for corrective action following the event.

A CPU trip during oxy firing would result in a blocked exhaust path until the stack tight shut-off (TSO) damper opens. If the stack TSO damper did not open or was delayed, the system pressure would begin to rise. Of interest was the potential impact on the structural integrity of flues and equipment and the possibility of maintaining boiler operation through and after the event.

A pulverizer trip represents a significant and rapid loss of heat input to the boiler and resulting flue gas product. If not carefully managed, this would have resulted in a rapid drop in flow to the CPU and potential problems for the booster fan to control the pressure at its inlet.

Since an ASU trip initiates a Main Fuel Trip (MFT), the response was straightforward and was not evaluated at Phase II.

Worst-case modeling conditions simulated two separate trips, each with two conditions selected to span the anticipated range of response possibilities;

a) CPU Trip:
   - CPU flow stops instantaneously
   - Two conditions for stack TSO damper response
     (i) does not open rapidly – remains closed
     (ii) opens in 5 seconds after 5 second control signal delay
       (purchased stack and CPU TSO dampers can open in 1second with no delay)
b) Single Pulverizer Trip:
   - One of the two operational pulverizers experiences a trip (in oxy-mode)
   - Two conditions for CPU response
     (i) does not run-back and continues at 100% of BMCR CO_2 compression rate
     (ii) does run-back to 50% BMCR CO_2 compression rate along a defined transient

A summary of Dynamic Model preliminary results for these worst-cases were:

a) CPU Trip

The preliminary analysis indicated that the plant had between 20 and 40 seconds before the transient design pressure limit was reached. Since the stack TSO damper was to be fast acting (full stroke in 1 second), there would have been sufficient time for the stack damper to open and prevent any structural damage. Figure 3-3 shows the trend of the furnace pressure vs. time. It was also desirable to open the stack damper fast enough to avoid an MFT due to high furnace pressure (this limit was much lower than the structural pressure limit). Although additional evaluation was needed in Phase III, this analysis indicated it might be possible that the controls could be tuned and stack damper position set to accomplish this. If the unit could run through a CPU trip, it would have allowed time for the operator to decide whether to drop load and continue to run until the CPU was again available or shut the unit down normally for CPU repair.

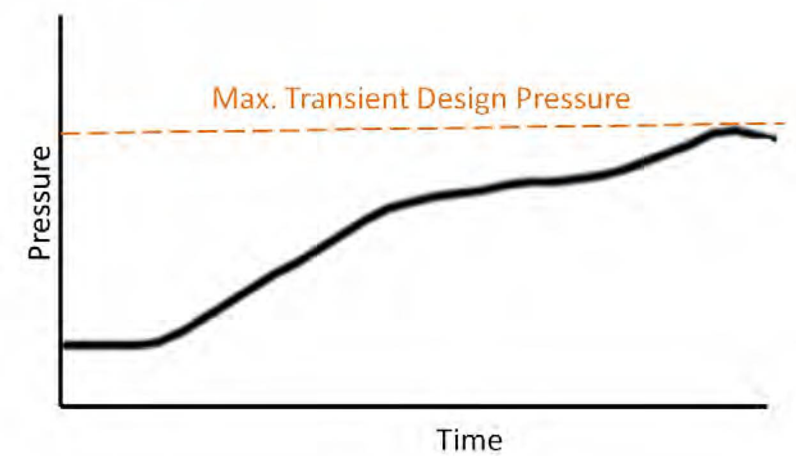


Figure 3-3: Transient Furnace Pressure vs. Time for CPU Trip with Closed Stack Damper

These preliminary worst-case results also qualitatively agreed with results from a separate B&W in-house developed low-fidelity analytical model. That second analysis provided a ball-park check on these higher fidelity modeling results.

b) Single Pulverizer Trip

Since the unit was designed to operate at MCR with two pulverizers in service, the loss of one pulverizer at high load and the resulting rapid decrease in furnace heat input and flue gas flow production could cause a CPU trip. The preliminary analysis showed that there was roughly one minute following a single mill trip before the minimum transient design pressure limit was reached at the CPU inlet flue (see Figure 3-4). Though this result was to be verified with final equipment and CPU characteristics in Phase III, it appears possible that the CPU could have been run-back to a lower load and avoided a CPU trip.

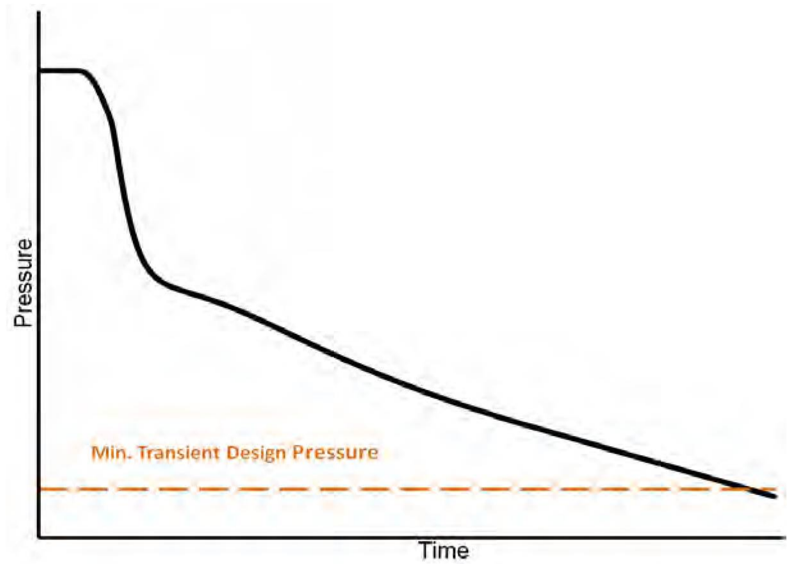


Figure 3-4: Transient Pressure at CPU Inlet vs. Time for Pulverizer Trip

3.3.2.4 Future Modeling

The Nominal Model, which was an engineering-grade model, was to have continued to be developed during Phase III, eventually evolving into the operator trainer.

Although the model continued to be refined, scenarios with full controls had not yet been simulated. The modeling effort described here was intended to test the control philosophies and evaluate key trips at a preliminary level. During Phase III, the model tuning based on final vendor equipment characteristics and complete control logics was to have been incorporated, and a more extensive list of trips and transients was to have been simulated to fully evaluate plant response.

The Nominal Model currently requires further development to add the steam turbine, condensate and feedwater, and other BOP systems, update physical and dynamic characteristics with actual vendor information, enhance the control logics, and finalize the link to a real-time CPU model(while the preliminary transient simulations have been run, the CPU was simulated by a boundary condition). Trips & transients still requiring additional simulation to be performed include:

1. Determine idle positions for the Air Intake and Stack controllable dampers (find damper position that minimizes fan upset during fast opening of TSO and establish opening rate)
2. Reassess MFT and CPU trip with full CPU model incorporated
3. Bringing a pulverizer into service
4. Pulverizer trip with full CPU model incorporated
5. Load ramps
6. Transition from air-to-oxy and oxy-to-air operation
7. Initial cold, hot and warm start-up studies

Future model development work was also to have focused on human factors and developing a link to a DCS simulator and/or hardware to facilitate implementation of an Operator/Engineer training program.

3.3.3 Plant Start-up

3.3.3.1 General Sequence

Details on the startup of the individual process islands are provided in subsequent sections. This section addresses the general sequence for a plant startup, which involves the following major process island steps (see Figure 3-5):

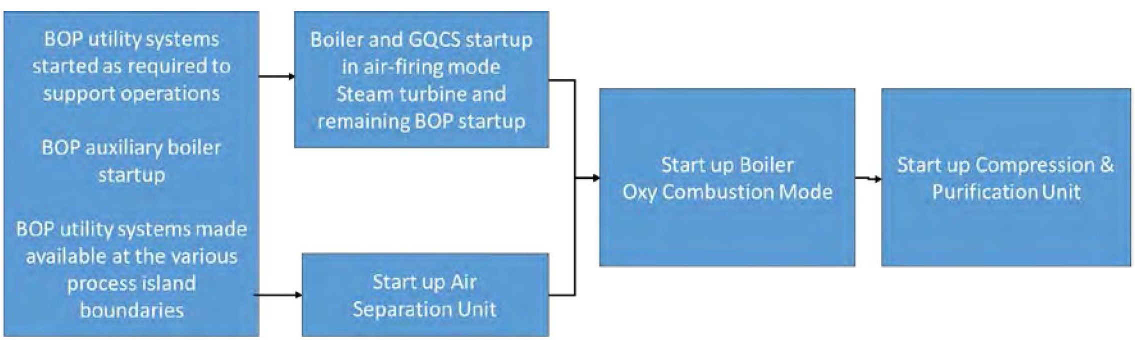


Figure 3-5: General Startup Sequence

The details of exactly when each of the above steps occurs, the extent to which BOP systems must be available, and the prerequisites necessary to perform the next step depends on the state of the plant at the time startup is commenced and especially the duration of the previous shutdown period. As with any plant, longer duration shutdowns require longer times for subsequent startup. Of the various island processes involved, the startup of the ASU is the most time consuming and will drive the overall plant startup time.

As an example of the general process sequence required for plant startup, the following describes a nominal plant startup after a 48-hour, or longer, prior outage, with no liquid level remaining in the ASU cold box (i.e., 80 nominal ASU startup time). The entire process is depicted in Figures 3-6 and 3-7.

With sufficient BOP utility and support systems established, the ASU is started. Prior to the ASU reaching 50% oxidant purity, preparations for boiler startup on air can be made, including placing the remainder of the BOP systems in service, inclusive of boiler fuel supply systems. Approximately 72 hours into the nominal plant startup sequence, once the necessary BOP systems are operating and control systems permissives are met, the boiler is started on oil in air-fired mode, and then transitioned from oil to coal, while still operating in air-fired mode. For further description of the boiler and GQCS startup procedures, see Section 4.3.3.5.

The process of starting the boiler and turbine and achieving stable operation at the transition point is expected to take about 8 hours. Once stable, coal-fired operation is achieved, and once the ASU is producing oxidant of acceptable quality, the plant is ready to transition to oxy-combustion mode.

The transition from air-firing to stable oxy-mode operation is expected to take about 30 minutes. Throughout the entire boiler startup process to stable oxy-mode operation, boiler exhaust flue gas is discharged to atmosphere via the main stack. With the boiler/GQCS in oxy-mode, the CPU can be started as soon as flue gas is available at a CO_2 concentration sufficient to support cold-box cooling procedures.

The CPU startup consists of progressively processing the flue gas in a stepwise fashion, exhausting the processed gas from each successive stage back through the stack until the entire CPU system has reached stable operation and processed CO_2 purity is proven to meet the pipeline specifications. At this point, the discharge flow of processed flue gas (CO_2) is transitioned from the stack to pipeline, for delivery to the storage site.

Overall plant startup time for this nominal scenario is around 103 hours from ASU start to CO_2 flow into the pipeline. As indicated previously, the total duration would be reduced to about 55 hours if the ASU had sufficient coldbox liquid level to start.

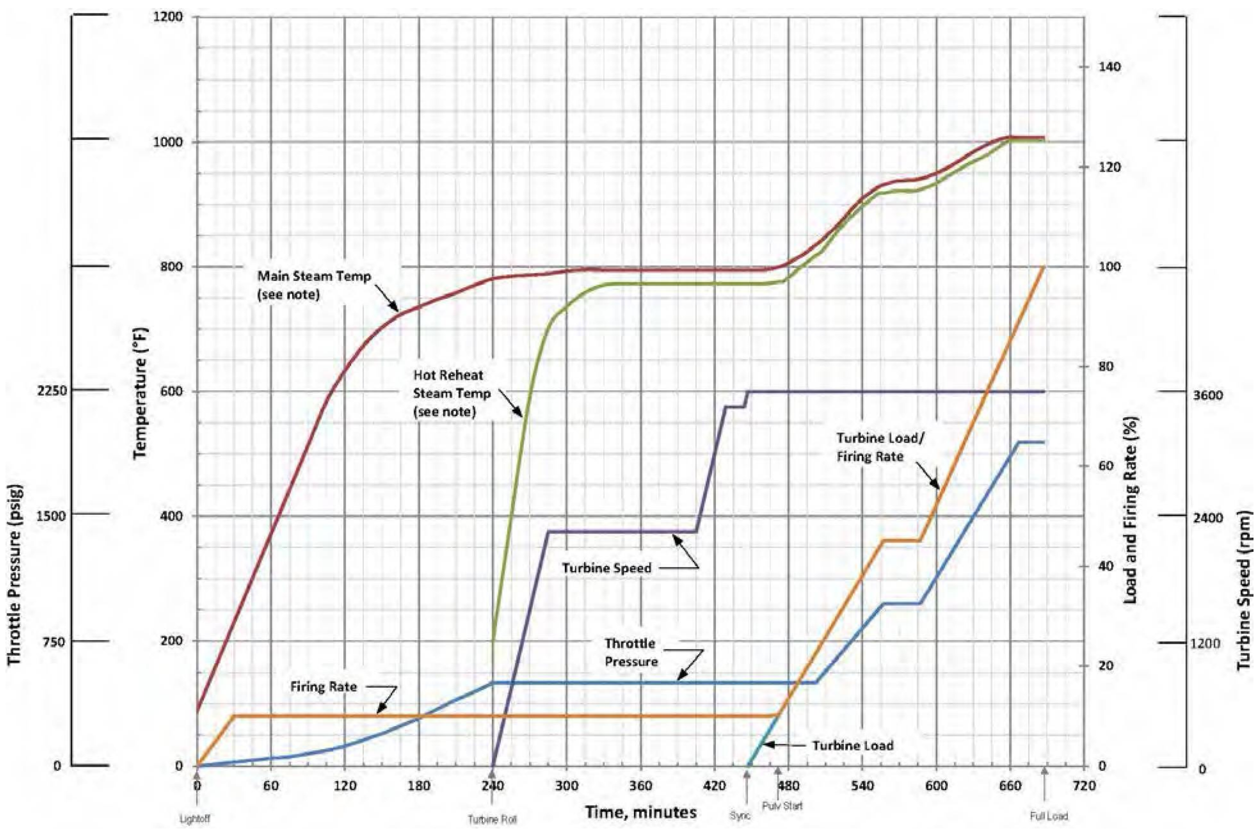
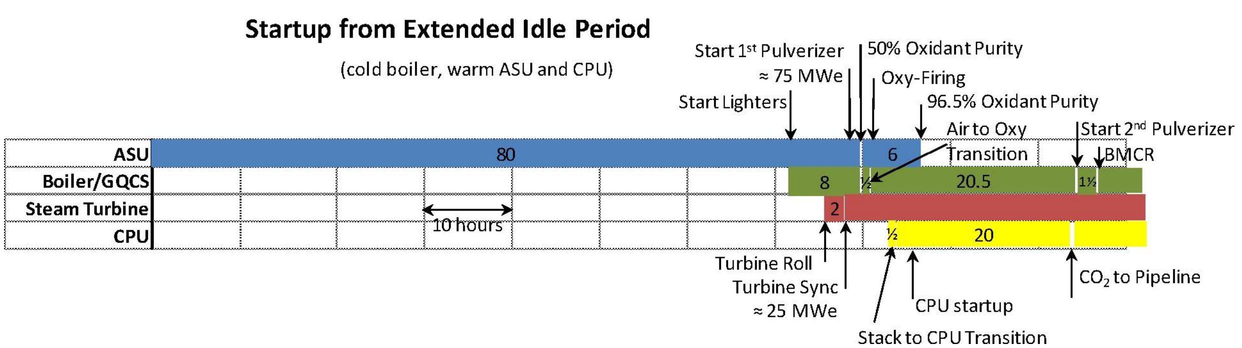


Figure 3-6: Boiler Turbine Cold Startup Curves



NOTE: 80 hr to achieve 50% purity would become about 32 hr if there is liquid level in the coldbox reducing the total duration from 103 hours to 55 h

Figure 3-7: Overall Plant Startup from Extended Idle Period

3.3.3.2 BOP Startup

To support operation and startup of the boiler and ASU, the following BOP systems and equipment were to be initially placed in service:

- Compressed Air:
  - Instrument air compressors and dryers: To provide air to air actuated valves
  - Service air compressors: To provide air for auxiliary and main boiler fuel atomization
- Plant Drains: To convey plant drains to treatment systems or to plant outfall
- Water Treatment and related support systems: To provide water for maintaining Condensate and Service Water Tank levels
  - LP Service Water: Provides cooling water to Unit 4 turbine building system, makeup to Unit 4 cooling tower, and supply to water treatment clarifiers
  - Raw Water Treatment: Clarifies river water for use in service water system
  - Service Water: Provides makeup water to UF/RO Water Treatment system and miscellaneous plant water users
  - UF/RO Water Treatment: Provides makeup water to DCCPS storage tank and Condensate storage tank
- Condensate: To provide auxiliary boiler water supply and ASU compressor cooling water
  - Start a condensate pump to establish flow through the condensate minimum flow recirculation system to the condenser hotwell
  - Establish flow through the ASU Island which recirculates to the condenser hotwell
  - Pressurize system to support makeup supply to auxiliary boiler
- Fuel Oil: To provide fuel supply to auxiliary and main boiler
- Main Cooling Water: To carry off ASU Island compressor heat load from the condenser
  - Start one circulating water pump
  - Operate cooling tower in bypass mode until heat load was established, then initiate cooling tower startup
- Main Cooling Tower Chemical Feed: To treat main cooling water to control biological growth and scale formation
- Auxiliary Steam: To provide steam for startup
  - Startup auxiliary boiler

  - Warm up auxiliary steam lines
  - Steam for turbine seals
  - Steam for ASU Island
- Gland Steam: To provide seal steam to turbine seals
- Condenser Vacuum: To enable condenser to flash high temperature water to achieve a lower temperature and condense steam
  - Start both condenser vacuum pumps and establish condenser vacuum
- ASU/CPU Cooling Water System: To provide cooling to ASU Island coolers
  - Start one circulating water pump and establish flow thru the ASU Island
  - Operate cooling tower in bypass mode until heat load was established, then initiate cooling tower startup
- ASU/CPU Cooling Tower Chemical Feed: To treat ASU/CPU cooling water to control biological growth and scale formation

Other BOP systems were to remain in their normal shutdown configurations until the ASU startup was near completion and the remainder of the plant was started. The following additional BOP systems and components were then to be placed in service to support boiler and turbine operation:

- Coal Handling: To convey coal to coal silos which store coal fed to boiler
- Closed Cooling Water Systems: To provide turbine and boiler equipment cooling
  - Turbine Building system
  - Boiler system
- Cycle Chemical Feed and Process Sampling: To provide water chemistry control
- Condensate: To provide condensate to the boiler feed water pumps
  - Place deaerator in service
  - Start second condensate pump to meet system demand
- Feedwater: Provides feedwater to boiler
  - Start one pump in recirculation mode until boiler was ready to receive flow
  - Start second boiler feedwater pump to meet system demand
- Steam Turbine Lube Oil and Hydraulic Oil: To provide lube oil and control oil for steam turbine operation
- Hydrogen and Hydrogen Seal Oil: To provide generator cooling gas

- Auxiliary Steam: To provide steam to miscellaneous plant users
    - The auxiliary boiler would have operated until the main boiler was producing sufficient main steam to meet auxiliary steam demand
    - After steam was admitted to the turbine and the reheat steam system had sufficient flow, cold reheat steam would supply the plant auxiliary steam needs
- Main Steam, Cold Reheat and Hot Reheat: To provide steam from the boiler to the steam turbine
    - Open main steam line drains to allow steam line warming
    - Admit steam to the turbine after suitable steam conditions are achieved
    - Roll turbine to rated speed and synchronize generator
    - Increase load on turbine in coordination with boiler controls
- Vent and Drains: To vent non-condensables and drain condensate from plant steam and feedwater systems
- HP and LP Extraction Steam: To provide steam for feedwater heating
- HP and LP Heater Drains: To return heater condensate drains to condensate system

When the boiler achieved 100% oxy-fire mode (approximately 45% boiler load) and prior to diverting flue gas from the Chimney to the CPU Island, the following additional BOP systems were to be in placed in service:

- DCCPS Cooling Water System:
    - Start one circulating water pump and establish flow thru to the DCCPS
    - Operate cooling tower in bypass mode until heat load was established, then initiate cooling tower startup
- DCCPS Cooling Tower Chemical Feed: To treat DCCPS cooling water to control biological growth
- DCCPS Trona makeup system to maintain pH on the cooling water loop
- DCCPS polishing scrubber
- CPU Compressor Condensate Treatment: To neutralize CPU compressor condensate for use in byproduct wetting and/or treatment for discharge in the Wastewater Treatment System
- DCCPS Wastewater Treatment: Treats DCCPS and CPU compressor condensate wastewater

3.3.3.3 ASU Startup

Cold Box 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 Cold-Box 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 cool down.

3.3.3.4 Steam Turbine Startup

This section describes the general startup of the steam turbine generator, from rolling off of the turning gear through full load operation. The steam turbine was to have been started up with the boiler in air combustion mode, in coordination with the boiler and other BOP systems, with the general startup process being similar to that for any conventional steam turbine generator. Significant limitations, associated with the Meredosia turbine design and the oxy-combustion cycle, are discussed herein, where applicable. Additional detailed limitations and starting instructions are provided in the steam turbine operating manuals.

The prerequisite BOP systems that would have needed to be in operation to support a turbine startup included the following:

- Condenser vacuum system was to be in operation to establish and maintain turbine exhaust vacuum
- Condensate system was to be in operation to maintain condenser hotwell level and provide gland steam condenser cooling and turbine exhaust hood sprays
- Main circulating water system was to be in service to provide main condenser cooling to maintain condenser vacuum once steam flow was initiated
- Auxiliary steam system was to be in service to provide turbine seal steam

The following turbine auxiliary components and systems were also required be in service:

- Turbine Lube Oil System was to be in normal operating mode
- Turbine Hydraulic/Control Oil System was to be in normal operating mode
- Generator Hydrogen and Seal Oil Systems was to be operating
- Turbine Seal Steam System and Gland Steam Condenser (GSC) was to be in service
    - Seal steam was to be applied

- Condensate flow through GSC was to be established

The turbine startup sequence was dependent on the temperature of the turbine rotor prior to startup. The initial rotor temperature was largely dependent on the duration of the previous shut down period. A typical cold start sequence is depicted in Figure 3-7. Regardless of the initial turbine condition, main steam was to be at a pressure of approximately 600 psig, with a minimum temperature of 100 °F superheat. Once these conditions were achieved, the turbine throttle valves were to be opened and steam was to be admitted to the turbine to slowly increase turbine speed. The governor valves were to be initially set wide-open and flow control was to be achieved using the turbine stop valve. The allowable acceleration rate of the turbine was dependent on the mismatch between steam temperature and turbine metal temperature, as specified in the turbine operating manual.

For a cold start, with turbine metal temperature in the HP or IP turbine less than 250 °F prior to start, the turbine was to be initially accelerated at approximately 50 rpm per minute to a speed of 2,250 rpm. At 2,250 rpm, a hold or soak period was required to allow the turbine rotor to achieve a more uniform temperature prior to loading, to avoid excessive component stresses from developing due to thermal gradients. The soak time was dependent on the turbine metal temperature, ranging from 1 hour minimum for turbine temperature just under 250 °F, to 3 hours maximum for turbine at ambient temperature. Once the soak period was complete, turbine speed was to be increased to synchronous speed.

For a hot start condition, with turbine rotor temperature greater than 250 °F, no soak period was required and higher acceleration rates were to be used to bring the turbine up to synchronous speed, again depending on actual steam-metal temperature mismatches. Maximum recommended acceleration rates under best case hot start conditions would have resulted in achieving near-synchronous speed in about 10 minutes.

At a turbine speed of approximately 3,450 rpm, control of the turbine was to be shifted from the throttle stop valve to the governor valves. This transfer would have require approximately 15 minutes to regain stable operation, at which time, turbine speed was to be brought up to the actual synchronous speed of 3,600 rpm.

Once at synchronous speed, the generator was to be synchronized with the grid and the generator breaker closed to load the turbine to an initial minimum stable load of between 5% and 10%. Turbine load was then to be increased in coordination with the boiler until the air-to-oxy transition point, at approximately 45% load, was reached. The recommended rate of turbine load change was variable, as specified in the turbine operating manual, depending on the magnitude of the load change and the existing turbine throttle and metal temperature conditions. Boiler and turbine load are held at the transition point until stable oxy-combustion operation was established, at which time the boiler and turbine load were to be ramped up to MCR.

3.3.3.5 Boiler and GQCS Startup

The boiler and GQCS should be started up in parallel with the ASU, timed in such a way that the boiler is ready to transition into oxy-combustion mode at the same time that the ASU begins producing oxidant of acceptable quality and quantity. This will minimize environmental issues with running the boiler in air fired mode, and the economic consequences of producing oxidant that is not being used.

Boiler Startup – Air Firing

Until the boiler reaches the load at which it is possible to transition into oxy-combustion mode, the boiler, GQCS and steam cycle startup sequence is essentially identical to that of a conventional, air-fired boiler.

As indicated in Figure 3-8, the stack dampers, as well as the PR, and SR fan air intake dampers are fully open, and the PR and SR recycle dampers and CPU TSO damper are fully closed for air operation.

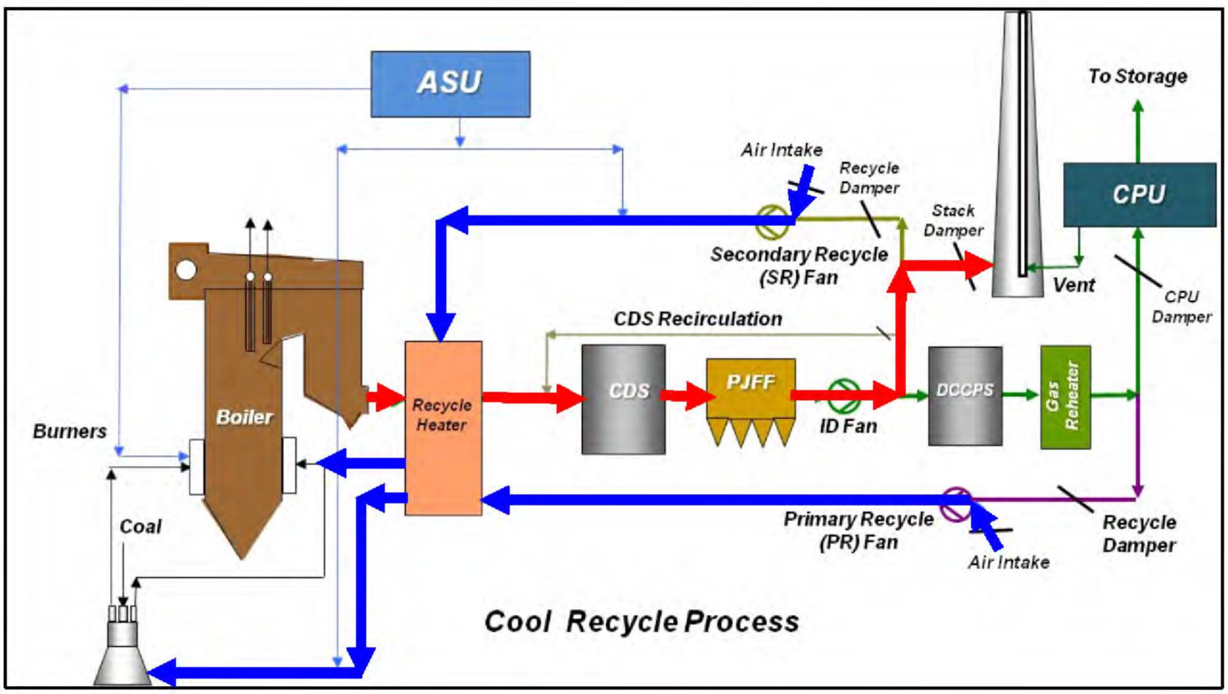


Figure 3-8: Boiler Startup – Air Firing

The following describes the major steps in boiler and GQCS 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. Lighter heat input 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 can be started up (see Section 4.3.3.4 for turbine startup description). When the boiler and turbine components have reached the desired temperatures, the first pulverizer can be started and coal firing initiated.

Prior to starting the first pulverizer, the CDS system must be started. The CDS recirculation damper is released to open, allowing flue gas from the outlet of the ID fan to be returned back to the CDS inlet in order to provide sufficient flow to maintain fluidization.

Once sufficient gas volume is available, hydrated lime and solids from the PJFF are injected into the bottom of the CDS. The pressure drop across the CDS is monitored to confirm solids are entrained, and when the entering gas temperature is high enough, water is injected. The PJFF compartment pressure drops are also monitored to determine when back-pulse cleaning is necessary.

With the CDS and PJFF in service, coal firing can commence. Air flow is controlled appropriately to maintain the desired excess air (oxygen) at the boiler outlet under these conditions. Once the first pulverizer is started and coal flow increased to the minimum pulverizer load (about 30% of full pulverizer input), 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 (to be determined during commissioning), but for initial design purposes, 45% of BMCR heat input is being assumed as the transition load.

In air-fired mode, PJFF exhaust gas is discharged to atmosphere via the stack. Since there is no NOx or Hg control at that point, it is advantageous to transition to the oxy-combustion mode at as low a load and as soon as practical.

Transition to Oxy-combustion

Once the boiler has achieved stable operation at the transition load, and the ASU is ready to supply oxidant at acceptable rates and purity, the transition from air firing to oxy-combustion can commence (see Figure 3-9).

Lower purity oxidant can be used during boiler startup to reduce startup time, but 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, it may extend the time required to reach 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 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 startups not only reduces the overall startup time but minimizes air emissions.

The transition process begins by initiating flue gas recycling.

Prior to the initiation of the transition, the SR and PR fan air intake control and isolation tight shut-off (TSO) dampers are fully open and the SR and PR flue gas flow control dampers are fully closed. The stack damper and stack TSO damper are both open and the CPU inlet TSO is closed. The transition to oxy-combustion begins by first adding a specific amount of medium pressure (MP) oxidant to the operating burners in order to maintain stable and attached flames throughout the process. In addition, the low pressure (LP) oxidant control valves to the hot primary, the tempering primary and secondary oxidant injectors, called Floxynators™, are released.

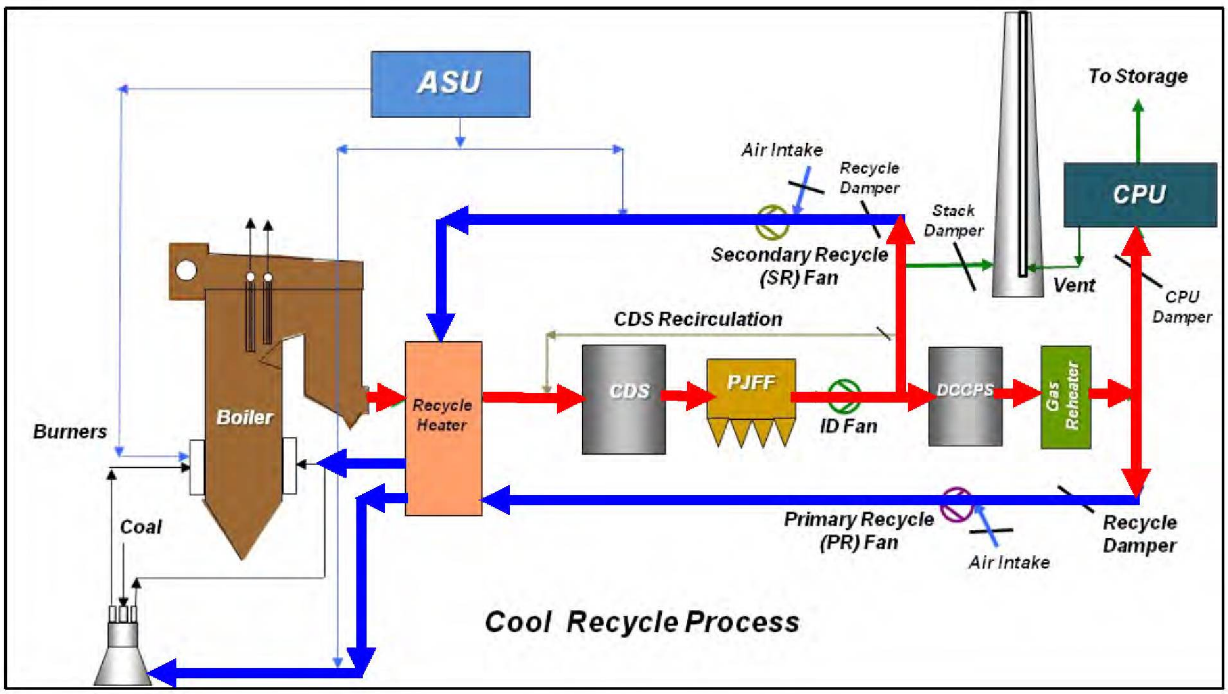


Figure 3-9: Transition to Oxy-combustion

The transition is initiated by opening the SR recycle 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 recycle damper is fully open, the SR fan inlet air damper is gradually closed, increasing the recycled flue gas flow into the SR fan inlet flue.

Once the secondary stream has been fully transitioned, the DCCPS and gas reheater must be started before admitting flue gas into the PR stream. Once the DCCPS sprays and gas reheater are in service, the transition of the primary stream can commence using the same procedure as the secondary stream; gradually opening the PR recycle damper. As the primary stream composition to the pulverizer 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 recycle damper is fully open, the PR fan air intake damper is gradually closed. Once both the PR and SR fan air intake dampers are fully closed, the boiler process is in full oxy-combustion mode and the PR and SR fan air intake TSO dampers can be closed.

If the desired recycle flue gas flow is not achieved when the SR and PR fan air intake dampers are fully closed and the flue gas recycle dampers are fully open, the stack inlet damper can be gradually closed to increase backpressure and 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 steady-state, 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 CDS and DCCPS and any flue gas losses to the environment.

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 stack to the CPU. This is accomplished by first opening the CPU TSO damper. The CPU booster fan is then started, venting separately to the stack, which will draw flow into the CPU and away from the main flue to the stack. The CPU booster fan will maintain appropriate pressure conditions at the CPU inlet to avoid an upset to the boiler process. Once the booster fan is controlling, the stack damper is gradually closed redirecting any remaining flow from the stack through the DCCPS, PR gas reheater, and to the CPU. During the transition, the water flow to the PR gas reheater will be modulated to maintain the outlet temperature above the dew point. Once all of the flue gas has been redirected from the stack to the CPU booster fan, the CPU process startup commences beginning with the main compressor (see CPU startup Section 4.3.3.6). The last step in the CPU startup is to send the nearly pure CO_2 to the pipeline for underground storage.

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 and density (air or oxygen/recycle gas) compensated to determine mass flows. 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.

Oxidant (a function of oxygen purity) is demanded from the ASU as MP and LP oxidant flows. The MP+LP demand is the quantity of oxidant required to deliver the difference between the theoretical stoichiometric oxygen requirement corresponding to the total Btu input and the oxygen available from any air coming into the PR or SR fans (measured). The LP demand is then trimmed (increased or decreased) to maintain the target excess oxygen at the boiler outlet (measured). The PR Floxynators™ automatically maintain a minimum oxygen concentration in the hot and tempering PR streams and the remainder of the LP oxidant demand is sent to the SR Floxynator™.

The oxidant flow to the 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 (MP+LP) is coordinated between the boiler and the ASU.

Once the plant is in full oxy-firing mode, a second pulverizer can be brought into service and load raised to BMCR (see Section 4.3.4, Load Changing).

3.3.3.6 CPU Start up

The normal CPU start-up was to be performed in sequence, such that each piece of equipment was successively started before sending pure CO_2 to the pipeline. When the CPU was warm, with cryogenic equipment at ambient temperature, the start-up sequence was to be as follows:

Pre-Heating

A pre-heating step for the filters was required using gas at a pre-heat temperature superior to 40°C and below design temperature. A gas temperature of 47°C was chosen for this purpose. This was to prevent condensation of acids when the CPU started drawing in flue gas. Acid condensation would have damaged the filter medium permanently. The heating was to be done with nitrogen going through an electrical heater.

Start Booster Fan with Flue Gas

During start up, it was anticipated that the boiler would have been operated at turn-down for the CPU, with approximately 45% of the flue gas routed to the stack. The blower was to be operated at minimum Inlet Guide Vane (IGV) position and would draw in acceptable flue gas while venting to the stack through its blow-off valve.

Once the blower was fully started, the stack damper would have been closed (minimum position). During this phase, the filter could have been regenerated with instrument air instead of dry CO_2 used during normal operation.

While the normal start was based on the 45% turn-down condition, booster fan start-up from a full load (100%) boiler condition was also evaluated and found to be feasible.

Start Flue Gas Compressor / Product Compressor

The integration of the flue gas compressor and the product compressor would have required start-up of both sections at the same time. The first step would have consisted of ramping up the pressure downstream of the blower as high as possible using the blow off valve. At the same time, nitrogen was to be injected at the inlet of the product compressor with the outlet closed to limit nitrogen consumption and pollution of the production line. Afterwards, the nitrogen pressure controller was to be switched to AUTO to compensate for leakage.

The feed compressor and product compressors would then have been turned on with their recycle full open. At this time, the blow-off of the blower was to be closed and venting of flue gas was to be done through the blow-off valve of the compressor.

Start Dryers

The dryers were to be pressurized and the sequencer of the drying system was to be switched on. Once the pressurization was completed, it would have been possible to regenerate the bed through a by-pass which had been added between the outlet of the driers and the inlet of the regeneration steam heater.

Pressurize Cryogenic Separation Section

The cold box was to be pressurized up to a minimum pressure with the dry gas using a valve at cryo-processing inlet.

Cool Down Cryogenic Separation Section

For cooling down, cold liquid impure CO_2 was to be injected from storage. This impure CO_2 was to be pressurized to around 16 bara so that the pressure difference with the distillation column would have been sufficient to naturally draw the liquid from storage to the column. The storage tank was to be filled during normal operation of the CPU.

When liquid had started accumulating in column and kettle, this cool down step would have been considered complete.

Stabilize Column

The column reflux was to be tuned so as to reach expected purity.

Switch Product Compressor to CO_2

To limit the nitrogen consumption, it would have been beneficial to switch the product compressor to process gas as soon as possible.

Prior to opening the compressor inlet valve and taking flue gas or potentially CO_2, the suction line was to have been pressurized up at the same pressure as the downstream heat exchanger. This way, no pressure drop in the exchanger would have occurred when the suction was opened. The compressor blow off valve was then to be opened to discharge the product.

Pressurize Production Line

This step would have consisted of pressurizing the discharge line of the compressor up to product pump inlet and purge pump outlet. This step was to avoid the risk of freezing, if the pressure was below 5.2 bara, and water hammer effect. The risk could have been avoided by pressurizing the system with hot gas before final cooling.

It was recommended that the production was to be at the required purity, as measured at the discharge of the product compressor, to avoid pollution of the production line. The risk would have been that light gases, such as nitrogen, present at the suction of the CO_2 production pump, might have damaged the pump during start-up. To mitigate this condition, a small manual vent line was to be added to remove the impurities.

Start Product Compression Chain

The fans of the CO_2 condenser were to be successively started and the water pump and water circuit would then have been started. The production pump was to be started with recycle full open until pressure was high enough to open the discharge valve.

Start Up Purge Pump

One pump was selected as backup; the other was to be started with recycle full open. Initially, the pump would have been cooled down while the vent line was opened. Once the required temperature had been reached, the pump would have been started up. The discharge valve would have been opened once the product pump and purge pump were in operation.

Start Non-Condensable Gas Treatment System (CATOX)

The by-pass heater and the by-pass CATOX were to be full open. Then the inlet and outlet valves would have been opened to pressurize CATOX and the by-pass CATOX would have been closed. Afterwards, it would have been possible to slowly heat up the non-condensable gas by closing the by-pass CATOX heater and switching it to AUTO. The heating rate would have been in accordance with the supplier recommendations.

CATOX would have been started as soon as possible, as it would have reduced the CO emission, but it would have had no impact on the critical path to CO_2 production.

Start Non-Condensable Gas Treatment System: Turbine Expander

The turbine could have been started as soon as heating CATOX was activated. The requirement was to have a gas temperature high enough to avoid low discharge temperatures that could have damaged the pipe.

The IGV of the turbine was to be set at a minimum position and the quick shutoff valve was to be opened. Then the turbine would have been started-up by slowly feeding the non-condensable gas to the turbine inlet through the action of closing the by-pass line.

Start Non-Condensable Gas Treatment System: Membranes

Finally, to reach the recovery target of the CPU, the membranes would have been started up.

Once the CPU was in full operation and the plant was in near-zero emissions mode, the CPU could have been ramped up along with the ASU and boiler to reach full capacity. It was expected that the warm CPU start up would have taken approximately 20 hours to reach full CO_2 production and recovery rate.

It should be noted that if the start-up followed a relatively short period of shutdown, the cryogenic section might still have been at or close to operating temperature. In this case, the cooling step would not have been necessary. Similarly, following a trip, the pressure was to be kept in the cryogenic section and production line, so pressurization steps could be possibly avoided. On the contrary, a shutdown lasting more than 48 hours would cause significant loss of liquid inventory in the cryogenic section because of boil-off. In this case, the startup sequence and duration would have been very similar to the first warm start-up.

3.3.4 Load Changing

3.3.4.1 General

As in other electric generating facilities, load changes are initiated (either manually or automatically) by varying the steam turbine speed control settings to demand either more (load increases) or less (load decreases) steam to the turbine throttle, thereby generating more torque on the turbine-generator rotor, which is converted to electrical current (load) in the generator. The boiler controls respond to the change in steam demand by increasing or decreasing the firing rate accordingly.

Since the steam turbine controls for this oxy-combustion plant have been configured for hybrid sliding pressure control, the turbine steam demand is normally achieved not by changing turbine throttle valve position, but rather by changing the steam pressure. Higher steam pressures result in higher steam density to support increased load settings by allowing more mass flow to be passed or “swallowed” by the fixed opening of the turbine throttle valves. Lower steam pressures result in less mass flow for the same fixed throttle opening.

While sliding pressure control is sufficient for normal steady-state operating conditions, rapid load changes and low load conditions require that throttle valve position control also be used to maintain stable operation. Due to the relatively large volume of the boiler and steam piping, steam pressure does not react rapidly to changes in boiler firing rate. Consequently, to meet the required plant ramp rate of 1.5% of MCR load per minute, valve position control is temporarily used during load changes to augment the sliding pressure control until the required change in pressure can catch up to the demand. For low load operation, minimum operating throttle pressure has been set at 500 psig. Once pressure reaches this minimum floor pressure, it is held constant, and any further load reductions are achieved by partially closing the turbine throttle valves to restrict steam flow.

When a signal to increase load is received, the boiler controls respond first by increasing the MP oxidant flow to the burners, this is to ensure that the furnace is an oxygen rich environment and to ensure flame stability during transient operation. During a load increase, the oxidant demand will lead fuel demand and excess O_2 is permitted to increase beyond the normal set point as load is changed. Next, a signal will be sent to the coal feeders to increase the fuel feed rate. As fuel flow increases, SR and PR flow increase as does MP and LP oxidant demands. When load is increasing, the increased PR and SR demand will temporarily decrease the flow to the CPU and the CPU booster fan maintains backpressure on the system to avoid any significant pressure upsets.

Once stable conditions are achieved at the new total heat input, MP oxidant demand is returned to its normal set point and excess O_2 is released to trim back to the normal set point at that load, which will adjust the LP oxidant demand.

When a signal to decrease load is received, the controls respond by sending a signal to the coal feeders to reduce the fuel feed rate. Next the oxidant demand will start to decrease after a prescribed time delay (lag) so that an oxidant rich environment is maintained in the furnace. As fuel flow decreases, SR and PR flow decrease as does MP and LP oxidant demands. When load is decreasing, the decreased PR and SR demand will temporarily increase the flow to the CPU, and the CPU booster fan will maintain backpressure on the system to avoid any significant pressure upsets.

Recycled flue gas and oxidant flow demands will follow changes in boiler heat release demands similar to normal air-fired systems. Since the PR streams are maintained at a specific oxygen concentration, changes in LP demand are realized primarily in the SR recycle stream.

Boiler performance curves are generated for the boiler control system so that the control system can feed forward to help make boiler load changes smoother and faster.

The individual load change capabilities for the boiler, GQCS, ASU, and CPU are sufficient to support the overall plant load change requirement of 1.5% of the MCR per minute.

The load changing process described here is nearly identical to the load changing process used on typical air-fired boilers. The most significant difference is that in an oxy-fired boiler, the oxidant flow is controlled independent of the SR and PR flow, whereas on an air-fired boiler the SR and PR flow is air which inherently contains oxidant.

3.3.4.2 Pulverizer Startup Description

Starting an additional pulverizer under oxy-combustion conditions is similar to starting a pulverizer under normal air firing. The total oxidant demand (MP+LP) is increased incrementally ahead of fuel input and the MP oxidant demand is temporarily increased to the load change set point to maintain flame stability of the in-service burners during the transient. The burner registers associated with the pulverizer to be placed in service are confirmed to be at light-off position. Load is raised using the in-service pulverizer(s) and the lighters (capable of 20% of the total BMCR input) to provide about the same additional heat input as the pulverizer being brought into service at its minimum load.

To start the pulverizer, PR flow is established when its burner line shutoff valves are opened and increased to the required value. As the PR flow is increased, the SR flow will correspondingly decrease to maintain total mass flow to the boiler at that load. The oxygen concentration in the PR stream is maintained at its prescribed set point which will correspondingly reduce the oxidant flow to the SR Floxynator™. After the PR flow is established to the pulverizer, the lance cooling steam flow is started to the burner lances coming into service and the lances are inserted. Once the lance temperatures are proven acceptable, the MP demand is increased to provide the burners coming into service with the required amount of oxidant based on the expected heat input from their pulverizer at minimum pulverizer load. The LP oxidant demand is temporarily increased by the same amount so as not to reduce the PR or SR oxidant flows, and excess O_2 is above the normal set point.

When oxidant injection to the burners coming into service has been established, the cooling steam is stopped, the feeder is started, and coal is fed to the pulverizer and burners. Heat input is automatically controlled as coal is fed to the pulverizer by rapidly reducing lighter input and backing down the other in-service feeder(s) and pulverizer(s) to maintain heat input. Because the unit is designed to be able to achieve full boiler maximum continuous rating (BMCR) burning the design 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 when a second (or third) pulverizer is brought into service to avoid excessive upsets in boiler heat input.

3.3.5 Shut Down

3.3.5.1 General

To shut the plant down from oxy-firing, load was to be reduced to the transition load, with one pulverizer in service, at minimum pulverizer load, and lighters (oil igniters) in service. The flue gas flow was to be transitioned from the CPU back to the stack and the CPU was to be shut down. The unit was then transitioned from oxy-firing to air-firing, in the reverse of the transition procedure as described in Section 4.3.3.5, Boiler and GQCS Startup. Once the transition was completed, the ASU was to be shut down. Following the transition back to air-firing, the pulverizer and PR fan were to be shut down and the lighter heat input was to be reduced until the steam turbine trips, after which the lighters were to be shut off. The unit was to be purged with the SR and ID fans and then fans were to be shut down, completing the boiler shutdown. Once the boiler was shut down, the associated BOP systems were to be taken out of service. The following sections describe this process in more detail.

3.3.5.2 Pipeline Shutdown- Vent Product CO_2

The pipeline and four injection wells were to be designed to accommodate the full flue gas stream from the oxy-combustion power plant, i.e., purified CO_2 stream from the CO_2 purification Unit (CPU). A pipeline shutdown was to have resulted in isolation of the pipeline. If necessary, the CO_2 in the pipeline could have been vented to the stack through a manual valve. Details of this venting operation would have required further evaluation, but the venting would have had to be performed slowly to limit freezing. While the production valves were closed, the CO_2 produced by the plant was to have been vented at the discharge of the CO_2 compressor and all downstream equipment, including aero-condenser and pump. By venting at the discharge of the compressor, upstream from the final cooler, it would have been possible to release hot CO_2, thus avoiding issues with freezing/plugging during gas expansion (see also Section 4.3.6.9).

3.3.5.3 CPU Shutdown

If necessary to shut down the CPU, the boiler can be maintained in oxy-combustion operation by venting flue gas ahead of the wet compression stage.

3.3.5.4 Transition from Oxy-combustion to Air-combustion

Transition from oxy-combustion back to air firing is the reverse of the transition procedure described in Section 4.3.3.5. Load is reduced to the transition load with one pulverizer operating at minimum stable load and the gas flow to the CPU is transitioned back to the stack by opening the stack TSO. The stack damper is then gradually opened from its idle position allowing flue gas to flow to the stack while backing down the CPU booster fan accordingly to control pressure at the CPU inlet. Once the stack damper is open, the booster fan can be ramped down and the CPU TSO closed to complete the shutdown of the CPU.

The boiler/GQCS is transitioned from oxy to air firing by transitioning the PR stream first, followed by the SR stream. The PR and SR transitions are the same, the MP oxidant to the in-service burners should be at the transient set point and the lighters to the in-service burners ignited. Then the controllable PR fan air intake damper is closed from its idle position and the TSO damper is opened. The controllable PR air intake damper is then gradually opened from its idle position allowing air into the fan inlet flue. As air mixes with the recycled flue gas, oxidant demand to the PR Floxynators™ will decrease to zero. As air is introduced, the LP demand will also decrease (MP demand is held until the transition is completed). Once the controllable air intake damper is fully open, the recycle damper is gradually closed until the PR fan is supplying only air to the process and PR recycle flow has been stopped. The DCCPS and gas reheater can be taken out of service at this point.

The SR is transitioned to air in the same manner. As the SR is transitioned, the LP oxidant demand will decrease to zero. Once the LP oxidant demand reaches zero, the LP control valves will be closed and the Floxynators™ can be locked out of service. During this process, the MP oxidant demand has been maintained at the transition set point. Once the PR and SR streams have been fully transitioned, the MP oxidant demand can be reduced to zero and the oxidant system shut down.

3.3.5.5 Boiler & GQCS Shutdown

Once both the primary and secondary streams have reverted to air, no oxidant is being injected into the recycle streams and the oxidant flow to the in-service burners is stopped. From this state, the pulverizer is then shut down followed by the PR fan. During this process the CDS remains in service and flue gas from the ID fan outlet is recirculated to maintain fluidization conditions. Once the pulverizer is out of service, the CDS can be shut down. This is done by shutting down the flow of recirculated byproduct solids and hydrated lime injection. Solids may be retained in the PJFF hoppers for short-term shutdown periods but the solids must be kept relatively dry by continuously operating the PJFF hopper fluidization system. Once the CDS has shut down, load is further decreased to turbine trip load using the lighters and SR and ID fans, and the turbine is shut down. The lighters are then shut off and the furnace is purged using the SR and ID fans. Once the purge is complete, the SR and ID fans are also shut down, unless they are needed to increase the boiler cool down rate.

3.3.5.6 ASU Shutdown

In the event that the ASU was required to shut down, all products were to be vented and the rotating equipment was to be gradually unloaded until a cold box shutdown was triggered. Rotating equipment in the cold box would have automatically stopped, and all cold box inlet, outlet and vent valves would have been closed, such that the cold box was completely isolated. If abnormal operating conditions required an immediate plant shutdown, interlocks were to conduct the process automatically. While shut down, the plant would have been continuously monitored anytime cryogenic liquid was present. Dead ends, containing cryogenic liquid, would have been purged periodically and the cold box casing would have been kept under continuous purge to prevent moisture ingress.

3.3.5.7 BOP Shutdown

Several of the BOP systems were to operate whether or not the power plant was producing power in order to provide services to support plant maintenance, general housekeeping, and to handle miscellaneous drains and wastewater. The following BOP systems were to have remained in service, regardless of plant operation:

- Plant instrument air service air: Compressed air system equipment was to have remained in service to maintain system pressure and to support maintenance use and support other systems
- Plant Drains: To collect plant wash down water, equipment drains, and rainwater and conveys to treatment systems or plant outfall
- Water Treatment Systems:
  - LP Service Water: To supply water to treatment for service water. LP service water was to have been operated in automatic mode to maintain service water tank level.
  - Raw Water Treatment: To treat LP service water for makeup to service water tank. Raw water treatment was to have operated in automatic mode to maintain service water tank level.
  - Coal pile runoff treatment: Coal pile treatment was to have operated in automatic mode to treat runoff from the coal pile prior to discharging to the plant outfall
- Service Water: To provide miscellaneous plant water users, e.g., wash down water. Service water was to have operated in automatic mode based on system pressure.
- Chemical feed systems: Chemical feed systems would have been required to support Raw Water Treatment and coal pile runoff treatment
- Fire Protection: Fire protection was to have operated in automatic mode based on system pressure
- Potable Water System: Potable water would have been required for restrooms, sinks, plant safety showers, and eyewash users

- Sanitary Drains System: Sanitary drains would have been required for transport of sewage city sewer system
- Nitrogen Purge System: Nitrogen purge system would have been required for extended outages. A nitrogen cap was to be placed on the boiler drum and superheaters, deaerator, and HP feedwater heaters.

After the ASU and CPU were shut down, the following systems could have been shut down:

- ASU/CPU Cooling Water System: Shut down operating circulation water pump and cooling tower.
- ASU/CPU Cooling tower Chemical Feed: Would only have operated when circulating water pumps were operated
- CPU Compressor Condensate Treatment: Once the CPU process island was shut down and secured, the condensate treatment system that was to have neutralized CPU compressor condensate could have been shut down
- Wastewater Treatment: The Wastewater Treatment system would have treated the neutralized condensate from the CPU compressors and DCCPS blow down. The system would have treated the nitrates and other constituents in the waste water stream using a physical/chemical and biological treatment process. To maintain the biological activity in the system during long term shutdown, an external source of nitrates would have been needed to maintain the biological activity to support start-up of the CPU/DCCPS. Otherwise, prior to restart of the plant, the biological treatment system would have to be repopulated with microorganisms. Acclimation of the microorganisms to the wastewater quality could have required several weeks. A short term shutdown, such as an extended weekend, would not require special precautions.

Following shutdown of the Steam Turbine Generator, Boiler, and GQCS, the following systems could have been shut down:

- Condenser vacuum pumps: Would have been shut down when turbine was at zero speed
- Turbine lube oil and hydraulic oil systems: Would have been shut down after turbine cool down
- UF/RO Water Treatment: Would have been shut down when the DCCPS storage tank and Condensate storage tank were full
- Main Cooling Water: Shut down operating circulation water pump and cooling tower
- Main Cooling Tower Chemical Feed: Would only have operated when the circulating water pumps operate
- Coal Handling: Would have been shut down to minimize long term coal storage in the silos

- Boiler Island Closed Cooling Water Systems: Pumps would have been shut down after boiler equipment had been cooled to acceptable levels
- Condensate: Shutdown operating condensate pump
- Feedwater: Operating feed water pumps would have been shut when suitable boiler drum level was achieved
- DCCPS Cooling Water System: Shutdown operating pump and cooling tower
- DCCPS Cooling Tower Chemical Feed: Would only have operated when the circulating water pumps operate

3.3.6 Major Trips

Though any component could have experienced a failure or trip, redundant equipment was selectively provided to allow for continued operation of many systems. However, certain major trips would have caused a Master Fuel Trip (MFT) and would have resulted in cessation of plant operation.

Trips of this nature would have included:

- An ASU trip, when in oxy-firing mode
- A steam turbine trip
- A fan trip, in the case of a single 100% capacity fan

Minor trips, such as CPU compressor trip, pulverizer trip, CDS trip, DCCPS trip, or pipeline trip, might not have led to a MFT and plant trip. The plant could usually have continued to operate through these minor trips and provided the operator the option to shut down the plant normally, or if the cause of the trip could have been resolved quickly, to continue to operate until the equipment was back on-line. More detailed descriptions of the causes and consequences of MFT, CPU, pipeline and CPU compressor trips are provided in later sections. A brief overview of the ASU, steam turbine, pulverizer, CDS, and DCCPS trips are provided here.

3.3.6.1 ASU Trip

Should the ASU trip during startup or air firing before the transition to oxy firing, the plant will continue to run in air-fired mode to allow the operator the option of continuing to run if the ASU trip can be quickly remedied or shut down if it cannot (NOx emissions are the main consideration in continuing to operate). Should the ASU trip during the transition or when oxy firing, an MFT is automatically initiated.

3.3.6.2 Steam Turbine Trip

Prior to synchronization, a steam turbine trip will not initiate a shutdown of the boiler. In this pre-synchronization condition, the boiler firing rate and steam flow, including reheater steam flow, are low enough that the resulting transient can normally be accommodated by the control systems, without tripping other components and systems and without overheating of the reheater tubes. This allows operators the opportunity to recover and restart the turbine without the delay of a boiler restart.

Once synchronized, a steam turbine trip will automatically initiate an MFT to protect the boiler reheater from overheating due to the loss of reheat steam flow under the relatively high boiler firing/load conditions.

3.3.6.3 Pulverizer Trip

On a coal-fired boiler, when a pulverizer trips, there is a load runback on the turbine due to the rapid loss of heat input to the boiler. Though this can be a severe transient, the control system is usually able to compensate (depending on the steam turbine response) and avoid a unit trip. In the event of a pulverizer trip, the total oxidant demand (TOD) is maintained until combustion is stabilized to ensure safe conditions. If the event is too rapid it will initiate a MFT.

Since the Meredosia unit was designed to operate at MCR with two pulverizers in service, the loss of one pulverizer at high load and the resulting rapid decrease in furnace heat input and flue gas flow production could have also caused a CPU trip. Preliminary dynamic modeling results indicated that it might have been possible to avoid a CPU trip, but this scenario needed to be further verified by modeling in Phase III and by controls tuning during commissioning.

3.3.6.4 Circulating Dry Scrubber (CDS) Trip

The following events could result in a trip of the CDS-Pulse Jet Fabric Filter (PJFF) system:

- Loss of both hydrated lime rotary feeder/drag conveyor trains that were to be used to manage the turndown of lime addition
- Loss of fluidization in the PJFF hoppers or recirculation slides
- Loss of recirculation gas flow and collapse of the CDS bed due to operating at low load
- Loss of humidification water, which could lead to high temperature at the inlet of the PJFF and reduction in SO_2 removal

Though it might be possible for the boiler to run through a CDS trip for a brief period of time, depending on SO_2 emission limits and the level of SO_2 concentration in the boiler, the CO_2 Compression and Purification Unit (CPU) would be tripped and gas flow redirected to the stack to ensure that SO_2 concentration and gas temperature do not exceed the maximums allowed at the CPU inlet.

Loss of the CDS bed might also cause an excessive flue gas pressure excursion at the CPU inlet and could result in a CPU trip and possibly a MFT. If the boiler and steam cycle were to continue to operate, it would be necessary to reduce load and exercise care to ensure that SO_2 concentrations and corrosive conditions in the boiler were not excessive.

3.3.6.5 Direct Contact Cooler – Polishing Scrubber (DCCPS) Trip

A DCCPS trip would occur when there was a loss of cooling water flow. Since there were to be redundant pumps, this would have been an unlikely event. However, in the event of a DCCPS trip, the temperature leaving the DCCPS would have increased from around 100°F to approximately 190°F. This increased temperature would exceed the maximum allowable CPU inlet temperature and would have resulted in a CPU trip with gas flow redirected to the stack until the trip was resolved. The PR Fan would automatically compensate for the increased temperature (volume flow change). The pulverizer outlet temperature set point might also have needed to be increased to compensate for the increased moisture.

In the event of a DCCPS trip it would have been advantageous to remain in oxy-firing mode, rather than transition back to air firing, because there would have been a significant reduction in emissions in oxy-firing mode. NOx emissions, although significantly reduced by oxy-firing, would have remained the limiting emission. Other emissions including SOx, particulate, acid gases and metals would have remained in compliance with emissions limits with the DCCPS offline. Once the DCCPS was returned to service, the flue gas leaving the GQCS from the stack could have been transitioned back to the CPU with minimal impact on plant output.

3.3.6.6 Master Fuel Trips (MFT)

The MFT system was to have been a combination of control system logic and a hard-wired relay circuit. When activated, the MFT would have stopped the flow of all fuel to the boiler within a period of time that would not have allowed a dangerous accumulation of combustibles in the furnace. The MFT relay circuit was to have been a “de-energize-to-trip” fail-safe system and would have required an operator action to reset. The operator would have reset the MFT circuit only after a boiler purge had been completed. An MFT was generated when an unsafe operating condition was detected by the control system or by the operator. The MFT was manually activated with the MFT pushbutton from a panel or from a pushbutton on an operator interface screen. The MFT pushbutton would have directly de-energized the MFT relay circuit and initiated an MFT condition in the control system logic. These MFT interlocks must never be bypassed to achieve boiler operation. The input signals used for these interlocks were hard-wired directly from the sensing elements and input to the BMS through redundant (two or more) digital input modules, though there was to be only one (1) field input contact representing the signal.

Master fuel trips would have occurred when the interlock system detected an unsafe condition, including the following:

- Loss of ignition
- Loss of fuel flow
- Loss of SR, PR, or ID fan
- Low excess oxygen at the boiler outlet (when in transition or oxy-firing mode)
- Less than minimum air flow (air-firing mode)
- Loss of oxidant flow or ASU trip (oxy-firing mode)
- High or low boiler steam drum level

- High or low furnace pressure
- High calculated pressure difference across the PJFF
- High PJFF inlet temperature
- High oxygen concentration in the SR or PR recycle stream
- Steam turbine trip (after synchronization)

The operator, at his discretion, could also have initiated a master fuel trip.

When an MFT was initiated, all oil lighters were stopped, all pulverizers were stopped and isolation (swing) valves closed, the PR fan was stopped, the oxidant flow to the primary Floxynators™ was stopped, the SR and PR air intakes were opened and the recycle dampers closed, the CPU TSO damper was closed, the stack TSO damper was opened, and the steam turbine was tripped. Flow of oxidant to the secondary Floxynator™ and the burners was continued to maintain an O_2 concentration of at least 21% by volume while the SR fan air intake damper was opened and the SR recycle damper was closed. Once the SR stream had reverted to air, the oxidant flow to the secondary Floxynator™ was stopped. The ID and SR fans would have continued to operate for furnace post-purge. With the controllable air intake damper at its idle position, air flow would have immediately entered the SR fan when the fast opening TSO damper was opened.

The control system would have closed all attemperator and sootblower supply valves. The air flow was not to be increased by deliberate manual or automatic control action. If the air flow was above the purge rate, it was allowed to decrease gradually to the purge rate for a post-firing purge. If the air flow was below the purge rate at the time of the trip, it was to be continued at the existing rate for 5 minutes and then gradually increased to the purge rate air flow and held at this value for a post-firing unit purge. All current NFPA 85 requirements must be satisfied. Usually, the unsafe condition could be corrected and the fuel reignited with little delay following a furnace purge.

3.3.6.7 Forced Shutdown

Forced shutdown procedures were to be used to remove the unit from service as quickly as possible, but in a more controlled manner than with the master fuel trip. This controlled shutdown process would have been identical to a normal load reduction and shutdown, but was to have been accomplished as rapidly as practical.

The procedure would have required that the turbine control valves be used to reduce the plant load down to the transition load.

Once at transition load, the flue gas flow that had been directed to the CPU flow would have been diverted to the stack, and the CPU would have been shut down.

Once the flow to the stack had been re-established, the unit would have reverted to air-firing and the turbine load would have been further reduced until it reached the turbine trip load.

After the turbine was removed from service, all fuel was to have been stopped and the unit purged.

3.3.6.8 CPU Trips

A CPU trip could have been initiated by the CPU or from the DCS. A CPU trip would have automatically and rapidly opened the stack TSO damper and closed the CPU inlet TSO damper. Since the controllable stack damper was to be set at its idle position, flow would have immediately been established to the stack at a rate that minimizes the pressure upset to the boiler/GQCS system. This would have required some tuning during commissioning but preliminary dynamic modeling had indicated that it would be possible to safely accomplish this transfer while keeping the remainder of the plant in service.

A DCS initiated CPU trip could have occurred for several reasons, including an MFT or a problem within the boiler or GQCS that required redirecting flow to the stack due to potentially unacceptable changes in composition, temperature, or pressure at the CPU inlet.

A CPU initiated CPU trip would have normally resulted in a rapid transition of the exhaust flow from the CPU back to the stack. Once this transfer was completed, the operator would have had to decide the appropriate action. Typically the plant would have remained in oxy-firing, with the load reduced to the transition load point, while the cause of the CPU trip was investigated. Once the cause had been determined, the operator would have then decided whether correction and restarting of the CPU could be accomplished in a short enough time to continue operating the plant considering emission limits, or if the plant was to be shut down normally to make repairs.

Within the CPU, there were several sub-system trip scenarios, similar to a pipeline trip, that could have allowed continued CPU operation, but which would have resulted in blowing off CO_2 production to the stack through pressure reduction while determining whether further shutdown or a global CPU trip would have been needed. In case of a main compressor trip, the booster fan outlet flow was to be redirected to the stack while determining if a CPU trip would have been needed. Since the flue gas would have still been flowing into the CPU inlet, this would have shortened the start-up time considerably once the compressor was ready to restart.

However, the loss of the booster fan or determination that a sub-system trip could not be remedied rapidly enough would have resulted in a full CPU trip.

For under-pressure protection, the filter downstream of the CPU inlet and upstream of the booster fan was to be equipped with passive pressure relief doors, capable of passing the full BMCR gas flow, that would open and allow air to enter the booster fan inlet before the pressure in the upstream flue could exceed its lower pressure limit.

3.3.6.9 Pipeline Trips

The system was designed such that the pipeline and wells could dispose of all CO_2 produced by the CPU in any scenario of operation. Under no circumstances was it envisioned that the operation of the power plant would be curtailed in order to match the capacity of the downstream facilities to accept CO_2.

If, for some reason, the wells were not able to keep pace with the full production of CO_2, this would have resulted in a pressure rise in the pipeline. In order to maintain the pressure in the pipeline within allowable limits, the volume of CO_2 in excess of the capacity of the pipeline and wells could be vented from between the compressor and the condenser for short periods until full pipeline capacity could be restored.

If the pipeline pressure could not be maintained below the maximum allowable pressure of the pipeline, this would have resulted in complete isolation of the pipeline, and venting of the total product stream.

Other reasons for isolation of the pipeline could have included excessive CO_2 temperature or off specification CO_2 composition.

The isolation of the pipeline was to have closed valves on the production line, tripped the product pump, and completely opened the blow-off valve at the discharge of the CO_2 compressor in order to vent CO_2 production.

3.4 Power Block – Process System Description

3.4.1 Oxy-combustion Process Description Overview

Figure 3-10 shows the oxy-combustion process schematic selected for the FutureGen 2.0 Project. The combustion process employed the B&W PGG-ALPC cool recycle process, firing a mixture of high sulfur bituminous coal and low sulfur sub-bituminous coal. The entire system was to have been integrated and optimized to the extent practical, given the existing steam cycle and BOP equipment. Heat from the ASU was to be incorporated into the condensate cycle, while heat from the steam cycle was to be used for flue gas reheating, as well as ASU and CPU needs and other process heat loads. Since FutureGen 2.0 involved repowering an existing steam turbine, turbine design limits restricted the amount of heat which could have been recovered from the oxy-combustion process and utilized in the power cycle to improve plant performance. Consequently, heat integration performance improvements that could have been realized for a new oxy-combustion plant design were not achieved for this project.

In the cool recycle process, hot gas leaves the boiler and passes through an advanced regenerative quad-sector (patent pending) secondary and primary recycle heater (aka air heater). This recycle heater was to be internally arranged to prevent any of the oxidant fed from the ASU from leaking into the flue gas which would then be lost to the CPU. Oxidant refers to the nearly pure oxygen (oxygen and a small amount of impurities of argon and nitrogen) produced by the ASU. Unnecessary loss of oxidant to the flue gas stream would have increased the size and auxiliary power consumption of both the ASU and the CPU.

Following the recycle heater, the flue gas would have passed through a CDS and then into the Pulse Jet Fabric Filter (PJFF) where Particulate Matter (PM) was to be removed. This combination of the CDS and PJFF would have removed almost all of the SO_2 and SO_3 and acid gases, and a substantial amount of mercury. From the PJFF the flue gas pressure was to be boosted by the induced draft (ID) fan, which controlled the pressure in the furnace to achieve a desired pressure at the outlet of the boiler, and the flue gas flow splits. A recirculation stream was to be sent back to the inlet of the CDS to ensure a minimum gas velocity through the CDS to maintain fluidization for all boiler loads. After this recirculation stream takeoff, the gas stream splits once again.

One stream from this split was to be boosted by the secondary recycle (SR) fan and then passed through a steam-coil gas reheater (like a steam coil air heater) to mitigate cold-end corrosion of the recycle heater by maintaining the flue gas temperature leaving the recycle heater above the acid dew point at lower loads.

The oxidant was to be supplied from the ASU as medium pressure (MP) oxidant and low pressure (LP) oxidant. LP oxidant was to be introduced into the secondary recycle flow after the SR fan via Floxynators™ before re-entering the recycle heater for heating prior to the boiler wind box. The SR fan was to control the secondary recycle flow to the boiler to provide sufficient mass for heat transfer.

The remaining flue gas stream would have passed through a DCCPS where moisture was to be reduced and most of the remaining SO_2 and particulate was to be removed. The saturated gas leaving the DCCPS was to be reheated by a water-coil gas reheater to avoid downstream moisture condensation and was again split with one stream flowing to the CPU, and the other supplying the primary recycle (PR) fan. The PR fan was to have provided the flow required to dry and convey the pulverized coal to the burners. LP oxidant was to be introduced into the primary recycle flow after the recycle heater via Floxynators™. The oxygen concentration in the PR stream was to be controlled at a specific concentration that mitigates risk of combustion in the pulverizers or coal pipes, while providing some oxygen in the primary stream with the coal to improve combustion. MP oxidant was to be injected directly into the burners to control combustion and the remaining LP oxidant was to be mixed into the secondary recycle as previously described.

When air-firing (during start-up and shut-down), the primary and secondary recycle and CPU streams were to be isolated by dampers and all of the flue gas leaving the ID Fan was to flow to the stack as in a conventional air-fired design. The primary and secondary recycle dampers were closed and, through their air intakes, the SR and PR fans would have provided fresh air to the recycle heater. The DCCPS and its downstream gas reheater were not in service in this mode.

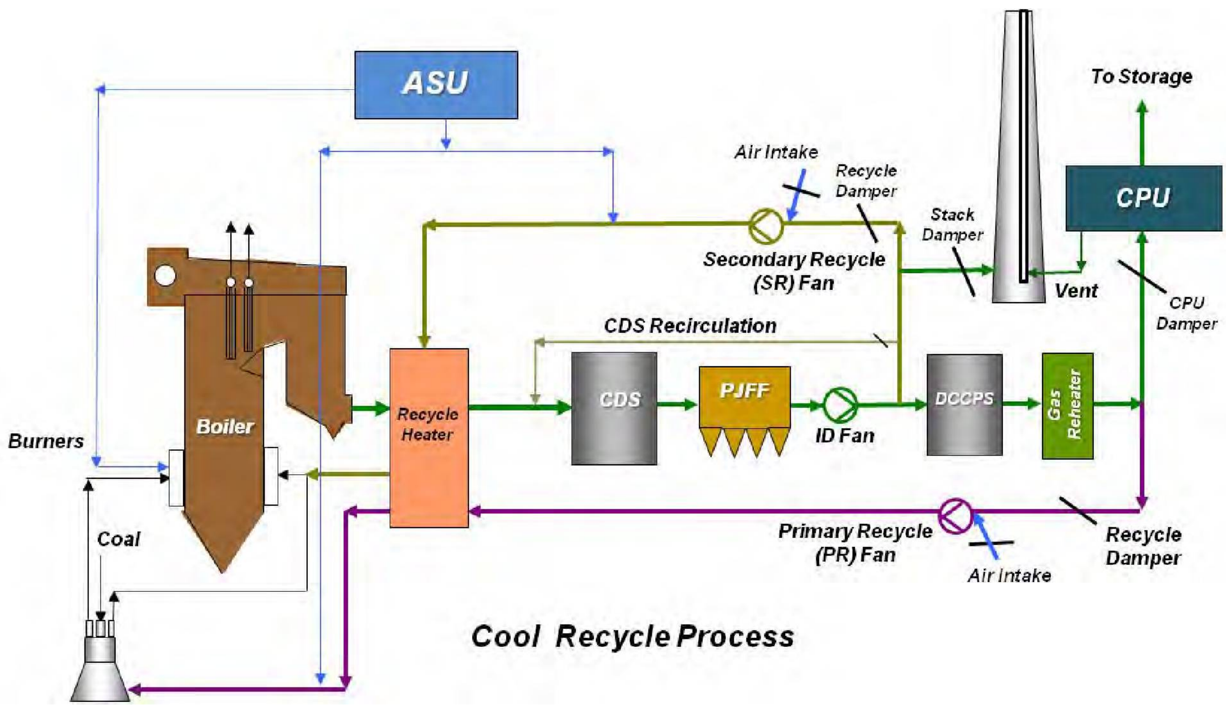


Figure 3-10: Oxy-combustion Cool Recycle Process Schematic

Boiler and Auxiliaries – Process System Description

3.4.2 Boiler and Auxiliaries Summarized Performance

The pulverized coal boiler plant was to have been designed to provide the required steam flow to generate a nominal 168 MWe (gross) with the steam power cycle (as described in the BOP System Description). The resultant boiler performance parameters are indicated in Table 3-7. The boiler and GQCS process schematic is shown in Figure 3-10.

Table 3-7: Overall Expected Boiler Performance

Main Steam Flow	515,961 kg/hr (1,137.5 klb/hr)
Reheat Steam Flow	448,200 kg/hr (988.3 klb/hr)
Feedwater Flow	521,132 kg/hr (1,148.9 klb/hr)
Main Steam Outlet Pressure	140.3 barg (2,035 psig)
Main Steam / Reheat Steam Outlet Temperatures	541.7 / 539.4 °C (1,007 / 1,003 °F)
Total Heat Output	1,450.7 GJ/hr (1,375.0 million Btu/hr)
Total Heat Input	1,666.7 GJ/hr (1,579.7 million Btu/hr)

Fuel Flow	72,870 kg/hr (160.6 klb/hr)

During Phase II, more in-depth engineering calculation and design work was to have been completed to confirm, optimize, and to work out the details of the design developed in Phase I. Additionally, B&W had worked with the major equipment vendors to refine the design of the equipment being supplied.

3.4.3 Boiler

The boiler was to be a pulverized coal (PC) fired 168 MWe (gross) boiler. It was to have been 7.92 m (26'-0") wide, 12.80 m (42'-0") deep, and the height from the bottom inlet headers to the roof was 38.94 m (127'-2"). It was to be a balanced draft Carolina type subcritical Radiant Drum Boiler designed for variable turbine throttle pressure operation. This unit had a series down pass arrangement, as depicted in Figure 3-11, and was to vary the flue gas recycle rate for reheat steam temperature control. In addition, a spray attemperator, located at the inlet to the reheater, was to be used for reheat steam temperature control during boiler transient conditions as well as for emergencies. The boiler was to have been designed to burn the specified range of Illinois #6 coal blended with PRB and was to utilize #2 fuel oil for the igniters.

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

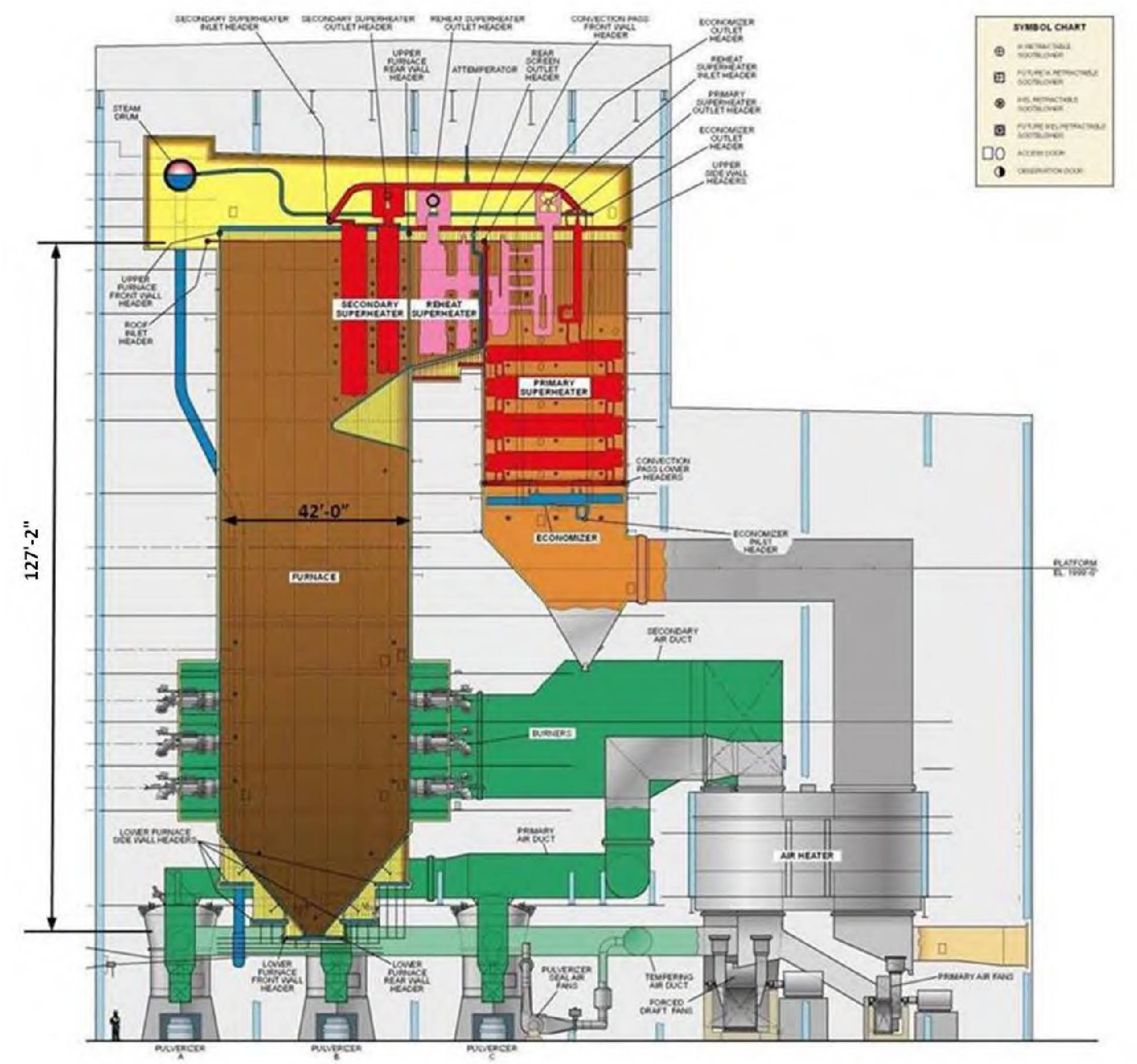


Figure 3-11: Carolina Radiant Drum Boiler with Series Down Pass

The water and steam mixture in the steam drum was to be separated by cyclone steam separators which provided essentially steam-free water in the downcomers and water-free steam to the drum outlet connections. The steam was to be 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 would have passed to the enclosure of the horizontal convection pass. The steam was to flow down horizontal convection pass enclosure and into the outlet headers which were also the inlet headers to the primary superheater.

Steam flow was to rise through the primary superheater and discharge through its outlet header and through two (2) connecting pipes each equipped with a spray attemperator. These spray attemperators were to be used to control the main steam outlet temperature.

The steam would then have entered the secondary superheater inlet header and flowed through the secondary superheater sections to the outlet header nozzle which connects to the main steam line.

Steam returning from the turbine would have passed through the reheat attemperator, located in the inlet piping, to the reheat superheater. It would then have flowed through the pendant reheater sections and exited the reheater through the outlet header which had a single end outlet.

The reheater outlet steam temperature would normally have been controlled by varying the gas recycle rate. However, during transient conditions such as load changes and other operational upsets, the attemperator, located at the reheater inlet, might have been used as a supplementary reheater outlet steam temperature control measure. During Phase II, detailed analyses of the furnace circulation and steam cooled membrane enclosure was to have been completed. As a result of these analyses the materials selections were optimized and finalized. Additionally, after the analyses, it was determined that several of the supply and riser tubes could be removed without any detriment to performance. This would have not only saved on material costs, but also on engineering, fabrication and erection costs.

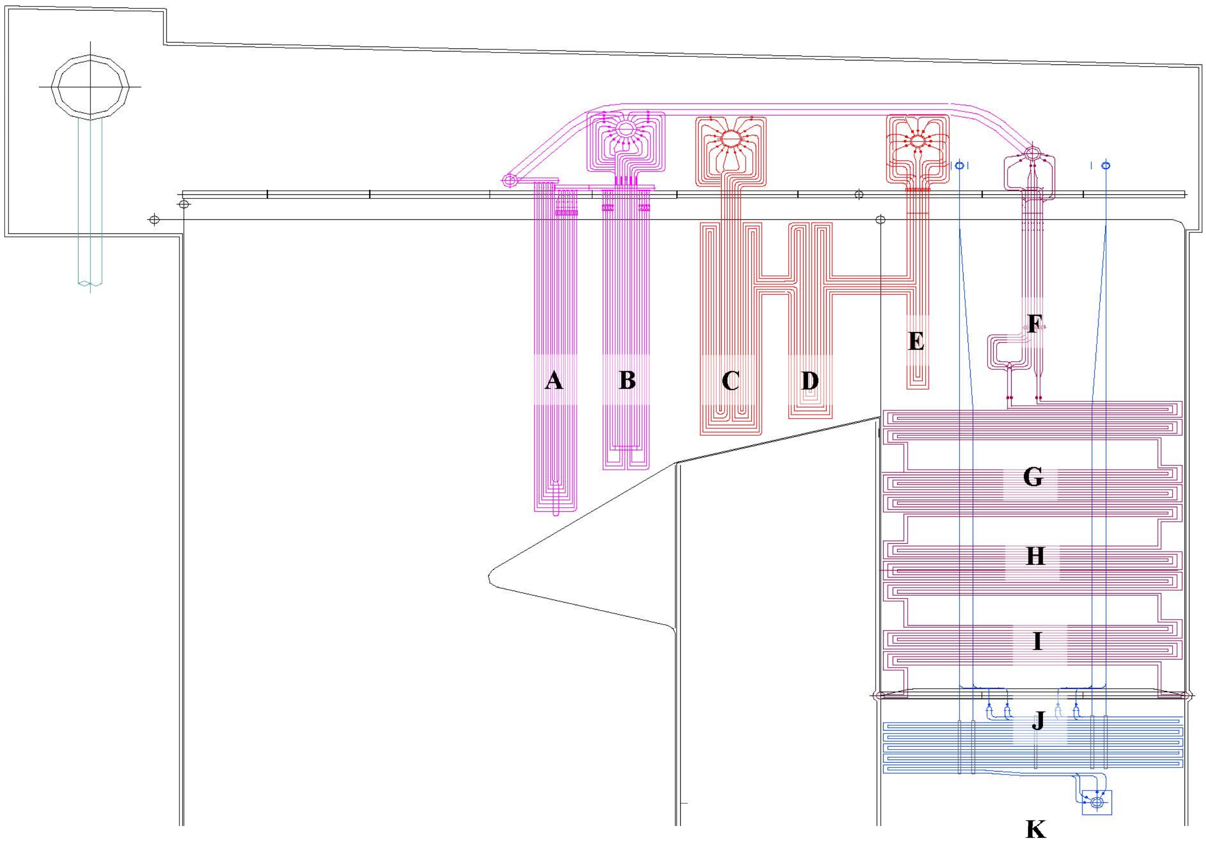
3.4.4 Superheater and Reheater Material Selection

This unit was to have two vertical secondary superheater banks and the primary superheater was to be comprised of four horizontal banks in the down pass and one vertical outlet bank. Note that this unit would not have had a platen superheater.

Several factors were 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 would have given careful consideration to gas side corrosion. The blending of Illinois #6 coal with PRB coal would have reduced the net sulfur and chlorine content. As a result, corrosion potential would have been reduced with increased blending of PRB.

A detailed heat transfer analysis of the superheater and reheater tube banks, for the purpose of tube temperature calculation and material selection, was completed in Phase II. This analysis determined that the use SA213TP310HCbN and SA213TP310H in the outlet portions of the superheater and reheater banks was not necessary. Therefore, a more economical material (SA213T91) that provides the necessary corrosion resistance was selected for these portions of the superheater and reheater banks. A summary of the superheater and reheater tube materials is shown in Figure 3-12.



BANK	DESCRIPTION	TUBE MATERIAL
A	SSH Inlet Bank	SA213T12 & T22
B	SSH Outlet Bank	SA213T22 & T91
C	RH Outlet Bank	SA213T22 & T91
D	2nd RH Pendant Bank	SA213T12
E	RH Inlet Bank	SA210A1
F	PSH Vertical Outlet Bank	SA213T22
G	1st PSH Horizontal Bank	SA213T22
H	2nd PSH Horizontal Bank	SA213T12
I	3rd PSH Horizontal Bank	SA213T12
J	4th PSH Horizontal Bank	SA210C
K	Economizer Bank	SA210C

Figure 3-12: Superheater and Reheater Tube Material Diagram

Since all of the recycle gas was to flow through the CDS – which would have removed SO_2 and SO_3 – and the primary recycle gas also would have passed through the DCCPS, the concentration of SO_2 and SO_3 in the recycle gas was low. Because the SO_2 and SO_3 have been removed from the recycle gas, it would have diluted the SO_2 and SO_3 concentration resulting from the combustion of the coal and oxidant in the furnace. This would have resulted in concentrations of SO_2 and SO_3 that were nearly the same as would be produced when firing the same fuel with air. Therefore, corrosion rates were expected to be very similar to an air-fired boiler burning this type of coal.

3.4.5 Recycle Heater

One (1) quad-sector regenerative recycle preheater (aka air heater) was to be provided. The recycle heater was to be sized to reduce inlet flue gas from approximately 349 °C (660°F) to approximately 171 °C (340°F), excluding correction for leakage, at the BMCR load when firing the typical blend of Illinois #6 coal and PRB.

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

As shown in Figure 3-13, the secondary sector was to be isolated from the gas sector by two primary sectors on either side. Since the primary recycle stream would have been at a higher pressure than either the secondary or the gas side, leakage would have occurred from the primary to secondary and from the primary to the gas side. As a result, no leakage would have occurred from the secondary to the gas side. Since the secondary recycle stream was the only stream that was oxygenated upstream of the recycle heater, no injected oxygen would have been lost to the gas stream. The oxygen for the primary stream was to be injected downstream of the recycle heater.

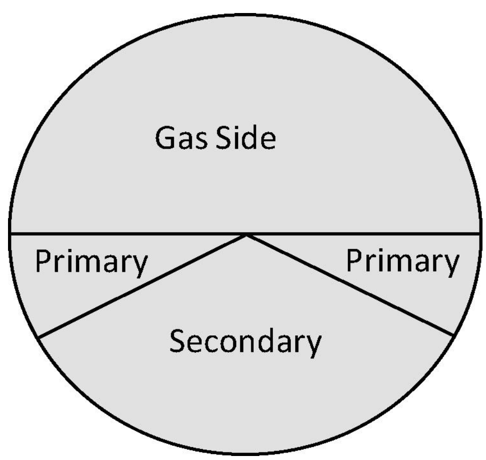


Figure 3-13: Recycle Heater (Plan View)

Although no injected oxygen was lost to the gas stream in this recycle heater sector arrangement, the overall leakage to the gas was increased due to the high pressure differential between the primary sectors and the gas sector. In addition, generally leakage rates, on a mass basis, were higher when in oxy-firing mode due to the higher densities of the gases as compared to air-firing.

3.4.6 Pulverizers

Three (3) B&W-75G pulverizers, as depicted in Figure 3-14, with external, manually adjustable, classifier vanes, were to be located along the boiler left side wall. These pulverizers were to be sized to meet the expected Boiler Maximum Continuous Rated (BMCR) load requirements with one mill out of service while firing the specified typical coal blend. Each pulverizer feeds four (4) burners, which was one level of burners (front and rear wall). Coal was to be dried in the pulverizers and conveyed through the burner lines to the burners with recycle gas. Functionally, the coal pulverizers would have operated in the oxy-firing mode the same way that they would have in air-firing mode.

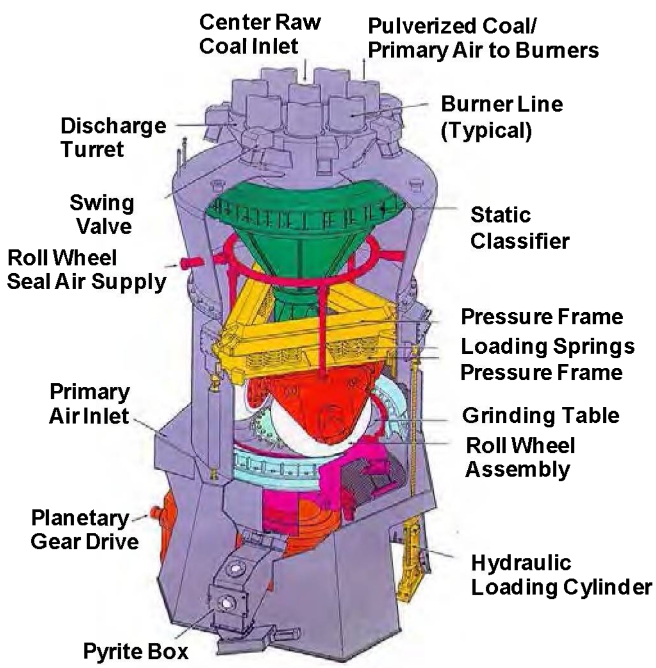


Figure 3-14: B&W Pulverizer

3.4.7 Burners

There were to be twelve (12) B&W HV-XCL^{TM} low NO_X burners, depicted in Figure 3-15, in three elevations on the front and rear walls of the furnace. It should be noted that each pulverizer would have supplied all of the burners on the front and rear wall of a given elevation, thus regardless of which pulverizer(s) was out of service, the burners in operation were always to be directly opposed. This would have enhanced combustion stability and encouraged high combustion efficiency.

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

The combustion system on this boiler was to be un-staged to mitigate furnace corrosion. When firing bituminous coals, the combustion system had a significant impact on the degree of corrosion expected in the furnace. Medium to high sulfur coals could have been 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 would have existed 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 was to have been utilized on this boiler. This was to eliminate the need for Inconel 622 weld overlay in the furnace. Eliminating staging was a corrosion mitigation strategy. B&W PGG recommended only spot protection with thermal flame spray of any local areas of corrosion should they occur in operation.

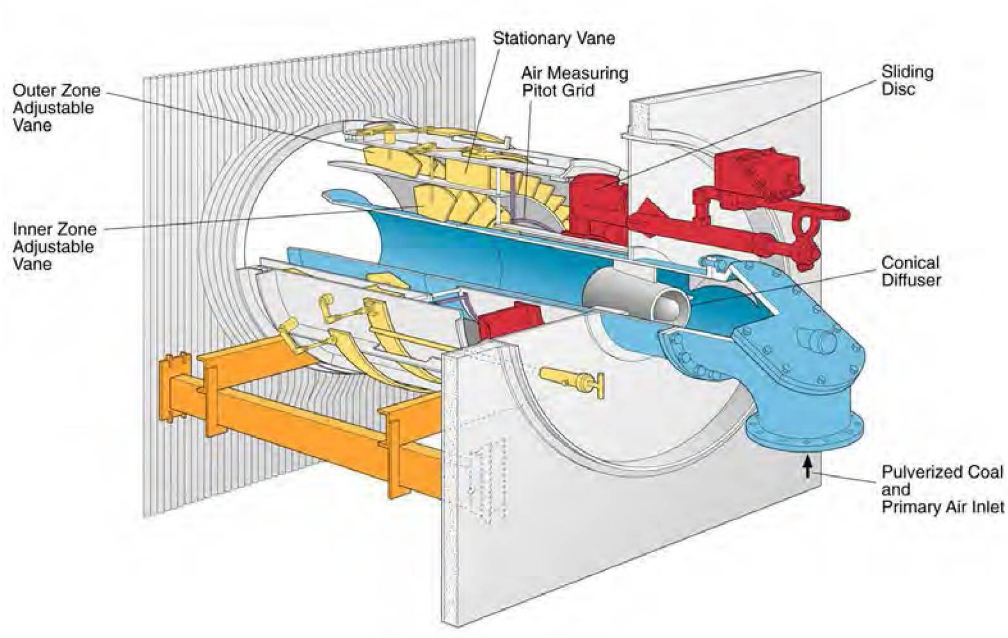


Figure 3-15: HV-XCL Burner

A single, retractable oil lighter, with air atomization, was to be installed in each burner for startup. Each lighter was capable of approximately 15% of the burner full load heat input (12 lighters at approximately 31.7 GJ/hr [30 MBtu/hr] based on 44,900 kJ/kg [19,300 Btu/lb] HHV and approximately 720 kg/hr [1,600 lb/hr] oil flow). Since this boiler was to be 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 was approximately 22.5% of the boiler full load heat input.

3.4.8 Oxidant Injection

The oxidant was to be injected in three locations: the primary recycle stream after the recycle heater and before the pulverizers, the secondary stream before the recycle heater, and into the burner flame. In the primary stream, oxidant was to be injected to maintain the O_2 concentration in the recycle gas at slightly less than the O_2 concentration in normal air. This was done to reduce the risk of fire in the pulverizers and coal lines. Capability was 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 was to be injected into the secondary recycle stream.

3.4.9 Fans and Air Intakes

The primary recycle fan was to be centrifugal, while the secondary fan and induced draft fan were both axial. The primary recycle fan would have supplied the recycle gas to the pulverizers for coal drying and to transport the pulverized coal from the pulverizers to the burners. The primary recycle fan was to be located between the flue gas reheater, immediately after the DCCPS outlet, and the recycle heater.

The secondary recycle fan would have supplied recycle gas to the burner wind box. It was to be located between the induced draft fan outlet and the recycle heater. The induced draft fan would have drawn the flue gas leaving the boiler through the CDS and the PJFF and delivered it to the stack and/or to the secondary recycle as well as the DCCPS, depending on whether the boiler was in air or oxy-firing mode and/or carbon-capture mode. The ID fan was to be located at the outlet of the PJFF and before the flue split to the secondary fan and the DCCPS inlet.

Both the primary and secondary fans had inlets arranged so that either air or recycle gas could have been supplied to them. The ducts were to have shut-off dampers so that only air was supplied to the fans when the boiler was in the air-firing mode and only recycle gas was supplied to the fans when the boiler was in oxy-firing mode. The inlet ducts also had dampers for controlling the air and recycle gas flow during the transition from air-firing to oxy-firing and vice-versa. Located downstream of the secondary fan was a steam coil heater that was to be designed to protect the recycle heater from cold-end acid dew point corrosion when operating at partial boiler loads.

The fans were to be designed to minimize leakage from the ambient into the gas stream because air infiltration would have introduced nitrogen which adds flow to the gas path and the CO_2 CPU and would have increased power consumption. The fans for this project were 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 were considered to determine the most economical design that both covered the range of operating conditions and optimized the fan performance at the expected normal operating points.

3.4.10 Sootblowers

The locations and quantities of sootblowers suitable for steam blowing were based on Diamond Power recommendations and B&W PGG standards for firing the specified range of coals.

Convection pass sootblowers were to be installed on one boiler side wall. The convection pass blowers were to be Diamond Power's IK-700's, the recycle heater blowers were IK-DM's and the furnace was to be water cleaned by hydrojets. Special sealing methods were to be used to prevent air infiltration into the boiler or flue gas leakage into the building from the sootblower openings.

3.4.11 Bottom and Convection Pass Ash Removal

3.4.11.1 Bottom Ash

The bottom ash removal system was to have consisted of a transition chute, submerged chain conveyor. The submerged conveyor was to have run from the furnace transition chute beneath the furnace hopper to the bunker. The conveyor was to include the maintenance rollout feature. This conveyor would 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 was to be provided for inspection and service access to the head section.

A hydraulic conveying system was also to be provided for pyrites (mill rejects). The pyrites system was to have transported the pyrites from the pulverizers to the submerged chain conveyor system.

3.4.11.2 Convection Pass Ash

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

3.4.12 Gas Reheaters

There were to be two gas reheaters in this process, the primary gas reheater and the secondary gas reheater. The function of the primary reheater was to heat the gas leaving the DCCPS, which was at saturation temperature to prevent condensation in the downstream flues and fans. The function of the secondary gas reheater was to maintain the recycle heater outlet (dirty flue gas) temperature above the acid dew point for corrosion protection at partial loads.

The primary gas reheater was to be located in the DCCPS outlet flue before it splits to the CPU and the primary fans. The gas was to leave the DCCPS at a typical temperature (depending on the season) of 21°C (70°F) to 38°C (100°F). The primary gas reheater was to heat this gas by about 14-17°C (25-30°F) using a condensate (water) extraction from the turbine as the source for the heating fluid. Since the gas entering the primary gas reheater was to be "wet" (saturated) with potential exposure to some sulfuric acid mist, the fins, tubing and casing were to be made of stainless steel.

The secondary gas reheater was to be located at the outlet of the secondary fan in the flue to the inlet of the recycle heater. The secondary gas reheater outlet gas temperature was to be controlled to protect the recycle heater from acid dew point corrosion at partial loads. In addition, this heater would have served the function of preheating the combustion air for the oil igniters during boiler start-up. The secondary gas reheater would have used cold reheat as the source for the heating fluid.

The locations of the steam and condensate extractions were 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 would have incorporated features to protect against corrosion, minimize the potential for gas side fouling, and were to be designed to accommodate future sootblowers, if operational experience indicated that they were needed.

3.4.13 Gas Quality Control Systems (GQCS)

The GQCS was to consist of a CDS for SO_2 scrubbing, a PJFF for the removal of particulate matter, and a DCCPS for flue gas dehumidification and SO_2 polishing. The dehumidification was 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 was necessary to minimize corrosion potential in the CPU. Wherever practical, flue gas instead of air was to be used for back-pulsing, sealing and conveying when in the oxy-firing mode to avoid introducing air into the system. Air would have diluted the CO_2 concentration and added unwanted mass flow, increasing power consumption and making CO_2 purification for the pipeline more difficult.

Refer to Figure 3-16 for a key isometric showing the GQCS.

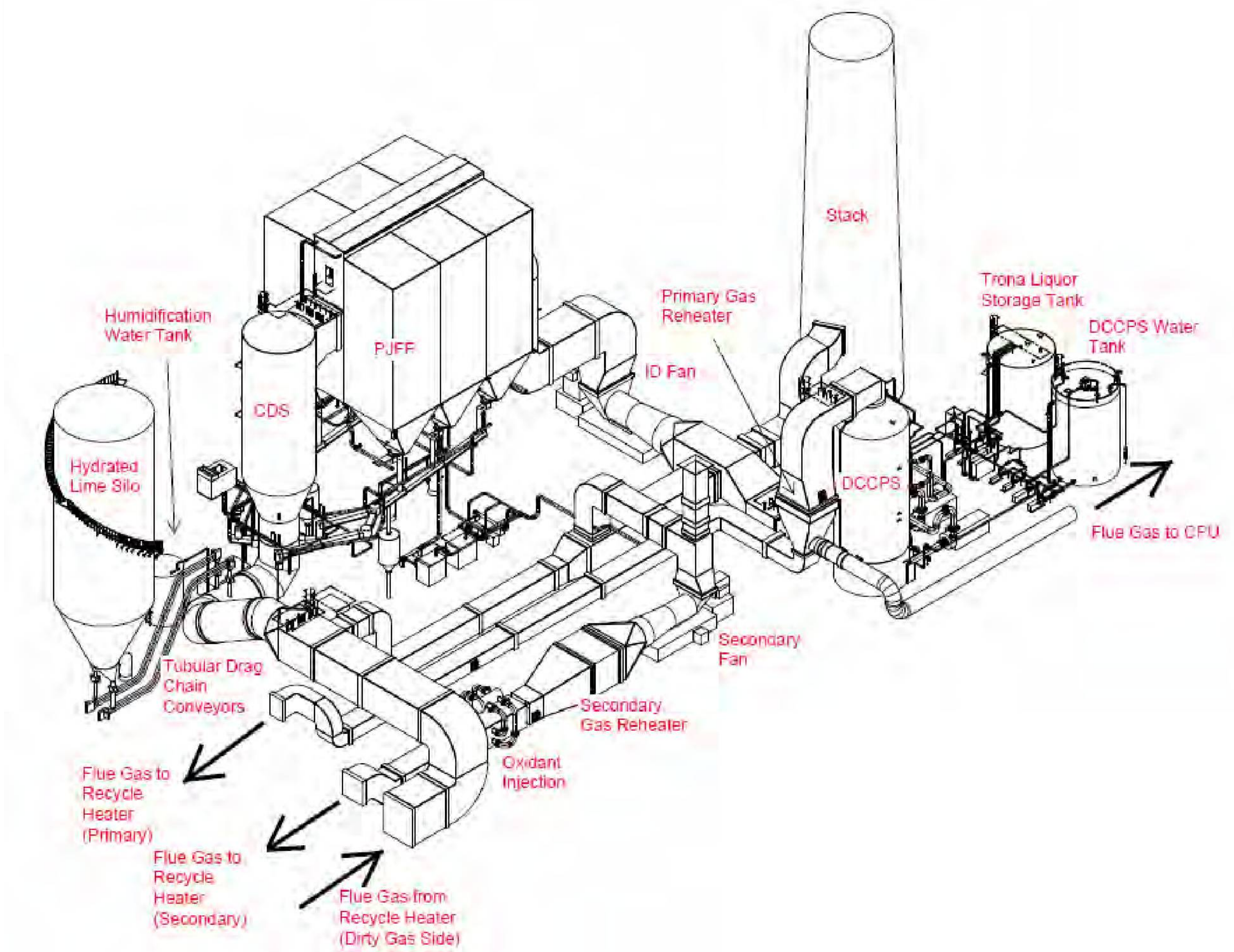


Figure 3-16: Key Isometric of the GQCS

From the recycle heater, all of the flue gas was to be sent through the CDS where over 95% of the SO_2 was absorbed. Other acid gases including SO_3, HCl and HF were to be absorbed at a similarly high efficiency and some mercury (Hg) was to be captured with the dry solid byproduct. Similar to a conventional dry scrubbing process using a spray dryer absorber (SDA), the flue gas exiting the CDS was not completely saturated with moisture but was to be controlled to an allowable approach-to-saturation temperature. The process would have required a certain amount of humidity to allow the absorption reactions to take place, but too much humidity could have caused bag wetting problems in the PJFF. The flue gas exiting the CDS would go to the PJFF, where more than 99% of the byproduct and fly ash material was to be captured. The CDS reaction products, including calcium sulfite, calcium sulfate and un-reacted lime along with other lime reaction byproducts were to be collected along with the fly ash in the PJFF hoppers.

The flue gas would then have flowed through the ID fan and, at low loads, a portion was to be recirculated back to the CDS inlet to maintain a minimum flue gas velocity through the CDS at all boiler loads. Maintaining the minimum velocity was important to ensure that solids remain suspended in the CDS. After the recirculation flue takeoff, the flue gas stream was to be split, with a portion passing through the secondary recycle fan and gas reheater and then back through the recycle heater to recover energy prior to entering the boiler wind box. Oxidant (from the ASU) was to be added to the secondary recycle gas just prior to passing back through the recycle heater.

The remainder of the flue gas from this split was to be sent to the DCCPS for dehumidification as well as polishing of SO_2, SO_3 and other acid gases. The saturated flue gas leaving the DCCPS would be passed through the primary gas reheater where it was heated to a margin above the moisture dew point. This flue gas was to be split again, with a portion sent to the primary recycle (PR) fan and the remainder directed to the CPU. The stream that was directed to the PR fan was sent through the recycle heater for heating and to recover energy from the hot flue gas exiting the boiler. A portion of this primary recycle gas would be passed through the recycle heater and a portion bypasses the recycle heater (referred to as tempering gas). Oxidant was to be added to both streams and the two streams were then to have been recombined to control the temperature of the gas leaving the pulverizers.

3.4.14 Circulating Dry Scrubber (CDS)

The CDS technology was ideal for the removal of acid gases (SO_2, SO_3, HCl and HF) from flue gases leaving smaller units firing medium-sulfur to high-sulfur fuels. B&W PGG was the exclusive North American licensee for Enviroserv's circulating fluidized-bed flue gas desulfurization (CFB-FGD) technology. The technology was based on the circulating fluidized bed (CFB) principle and uses dry calcium hydroxide ($Ca(OH)_2$ or hydrated lime) as the absorbent. The $Ca(OH)_2$ reacts with the common acid gases according to the following chemical reactions:

- $SO_2 + Ca(OH)_2 \rightarrow CaSO_3 + H_2O$
- $SO_3 + Ca(OH)_2 \rightarrow CaSO_4 + H_2O$
- $2HCl + Ca(OH)_2 \rightarrow CaCl_2 + 2H_2O$
- $2HF + Ca(OH)_2 \rightarrow CaF_2 + 2H_2O$

The products generated by the removal of SO_2 and HCl would have further reacted with the water in the flue gas to make up the composition of the end byproduct according to the following chemical reactions:

- $CaSO_3 + 0.5\ H_2O \rightarrow CaSO_3{*}0.5H_2O$
- $CaSO_4 + 0.5\ H_2O \rightarrow CaSO_4{*}0.5H_2O$
- $CaCl_2 + 2\ H_2O \rightarrow CaCl_2{*}2H_2O$

An acid gas removal efficiency of >95 % could have been reached with a CDS/PJFF system. In order to optimize the CDS process, flue gas, absorbent/solids, and water must be homogeneously mixed in the CDS vessel. This would have been achieved in the CDS absorber using four (4) venturis for solids injection and four (4) flow back lances for high-pressure water injection. The CDS itself was an almost empty, vertically-arranged flue with a venturi section. The flue gas was to enter the bottom of the absorber, turned and entered the venturi section where the recycled solids from the PJFF were to be directed into the bottom of the venturi. The solids and flue gas were passed through the venturis where the flue gas and solids were to be accelerated by the constriction of the venturis. The optimum heat and mass transfer properties of the CDS were the result of the venturis, which would have maximized the slip velocity between flue gas and the fine-core particles.

Above the venturis, in the absorber body, a high solids concentration and turbulent environment was to be established. The relatively high density of solids would have provided sufficient surface area for the absorption of the acid gases. Additionally, the high solids density would have allowed water to be injected directly into the absorber above the venturi section in order to cool the flue gas closer to the optimum acid absorption temperature. The water injection control loop was to be independent of the control loop used to control the removal of acid gases. The acid gas removal rate was to be controlled by adjusting the amount of fresh hydrated lime entering the CDS. The hydrated lime would have entered the CDS vessel via a tubular drag chain conveyor that would have dropped hydrated lime into the flue section just upstream of the inlet bend of the CDS vessel. The body of the absorber was to be cylindrical in shape and the length of the body would have been sufficient to completely evaporate the water sprayed into the absorber. After some internal circulation due to the turbulence in the absorber, the dry byproduct solids were to leave with the flue gas to the downstream PJFF.

There was a critical velocity required to suspend the fluidized bed in the absorber. Below this critical velocity, solids would have begun to fall out of suspension in the absorber. Therefore, a clean gas recirculation flue was to be used to recirculate clean flue gas from the discharge of the ID fan to maintain the flue gas velocity in the absorber safely above the critical velocity during periods of low load operation.

Refer to Figure 3-17 for a typical arrangement using a CDS Absorber with a PJFF particulate collector.

3.4.14.1 Absorbent Feed – Hydrated Lime

Hydrated lime was to be trucked to the site and pneumatically conveyed via a truck-mounted blower into the Hydrated Lime Storage Silo. A mechanical drag chain conveyor was to be used to transport the hydrated lime from the silo to the flue directly upstream of the CDS inlet bend. The flow of hydrated lime was to be controlled using a rotary feeder with variable frequency drive (VFD) at the silo hopper exit. The tubular drag chain conveyor would have transported the lime to the CDS inlet flue where a rotary airlock was to be used to drop the dry hydrated lime into the flue while minimizing air infiltration into the process. The Hydrated Lime Storage Silo would have had dual outlets with each outlet serving a dedicated rotary feeder/drag conveyor train. Either train or both trains might have been used to manage the turndown of lime addition needed for the design basis of the project. The silo would have had a storage capacity of four (4) days at the maximum design conditions.

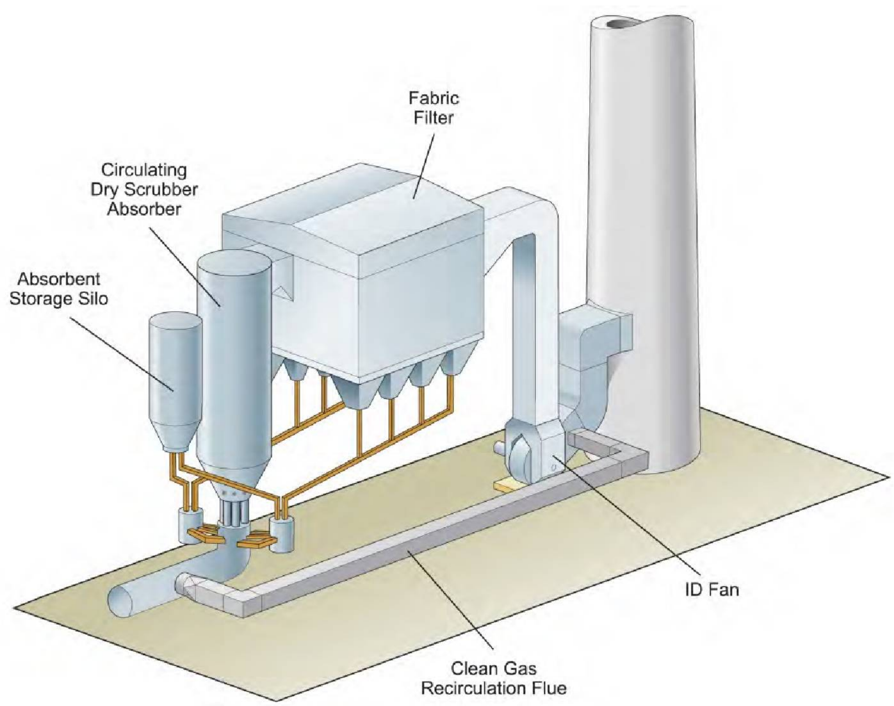


Figure 3-17: Typical CDS and PJFF Arrangement

3.4.14.2 Humidification Water

Water was to be sprayed into the absorber to cool and humidify the flue gas to an optimum temperature above the water dew-point to balance safe operating conditions and efficient acid gas removal. Fine water droplets would have ensured complete evaporation of the water before leaving the absorber. The water was to be introduced above each venturi by lance/nozzle assemblies designed to maintain the desired droplet size for the required turndown of the flue gas system. The pressure needed to achieve proper water droplet distribution was too high for a conventional service water system. Therefore a high pressure water system would have been required. This system would have pumped water in a continuous flow loop at a high pressure (~580 psig) to ensure availability of water for the absorber. The system was to consist of a small water tank, duplex strainer, redundant pumps, control valves and instrumentation, and spillback water lance/nozzle assemblies (see Figure 3-18). The water must be low in suspended solids but could generally have been poor in quality. For this project the source of the water was to have been a composite of primarily clarified river water with ability to accept other water streams on a batch basis from the waste water treatment system. Such other water streams might have included Reverse Osmosis (RO) reject water, Ultra Filtration (UF) reject water, treated DCCPS cooling tower blowdown water, and untreated CPU condenser blowdown water. A Humidification Water Tank was to have served as the collection point for the water streams and was a head tank for the high-pressure, multi-stage pumps that would have fed the injection lances.

Figure 3-18: Typical Spillback Nozzle and Lance Assembly for CDS System Humidification

3.4.15 Pulse Jet Fabric Filter (PJFF)

The single, 100% capacity, six (6) compartment PJFF was to be designed to remove the particulate matter and $SO_2/SO_3/H_2SO_4$ reaction products entrained in the flue gas discharged from the CDS absorber. Since it was critical to prevent air infiltration into the oxy-firing process, the pulse gas system was to use clean, dry flue gas (mostly CO_2) returned from the CPU for filter bag cleaning when in the oxy-fired mode. Instrument air from the plant compressed air system was to be used to clean the filter bags when the unit was in the air-fired mode. The solids removed by the PJFF but not recirculated to the CDS absorber was to have been sent to the Byproduct Solids Storage Silo. A pressure pneumatic conveying system was to be used to convey these unused solids to the Byproduct Solids Storage Silo.

The PJFF was to be a self-cleaning dust collector designed to remove particulate matter from the flue gas stream. The PJFF was to be designed to capture the majority of the fly ash/CDS reaction products from the gas prior to it entering the DCCPS. It was to be an integral component of the CDS system since the CDS relies on the recirculated solids collected in the

PJFF for additional gas-solids contact and absorption reaction. Figure 3-19 shows the PJFF that had been designed for this project.

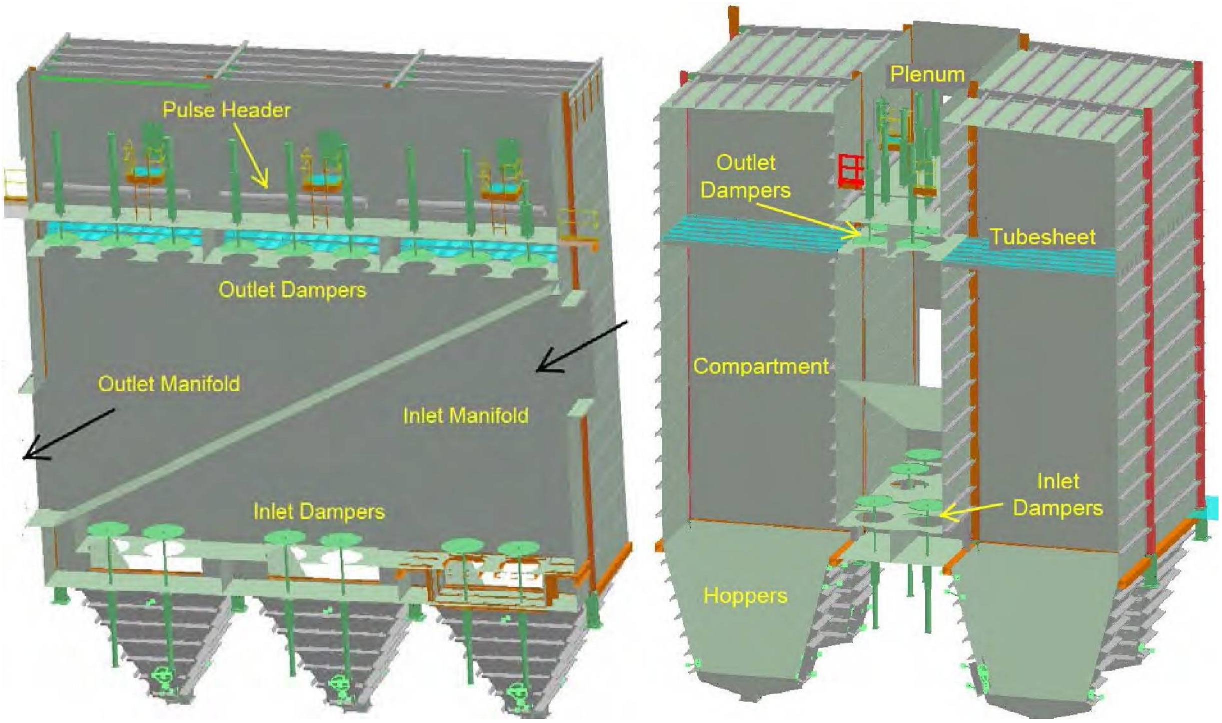


Figure 3-19: Pulse Jet Fabric Filter

The PJFF was to be located downstream of the CDS. Flue gas was to be directed into the individual compartments of the PJFF via the PJFF's inlet manifold. The particulate matter entrained in the flue gas was to be treated in the PJFF compartments, would have exited through the common outlet manifold, and then was to be directed to the ID Fan which would have discharged to the secondary recycle flue and DCCPS.

The PJFF consists of six (6) gas-tight filter bag compartments. Each filter bag compartment would have contained 729 filter bags. Each filter bag was to be 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 was to be approximately 2.99 to 1 ft/min. The air to cloth ratio with all compartments in service was to be approximately 2.49 to 1 ft/min.

Flue gas laden with particulate matter was to enter each PJFF compartment below the filter bags, slowing down and changing direction 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 would have resulted in some of the particulate matter falling directly into the hopper; the remainder was to be deposited on the outside surfaces of the filter bags.

Each compartment of the PJFF was to be equipped with a broken bag detector that was to have activated an alarm in the event that a filter bag breaks. The operator would then have isolated the affected compartment until the filter bag could have been replaced. The PJFF was to be designed to operate at full load with one compartment out of service.

Pulse Headers

To keep pressure losses at an acceptable level, the filter bags were to be periodically cleaned. During operation, the PJFF filter bags were to be cleaned using a short pulse of dry compressed medium; air during air-firing and dry flue gas (mostly CO_2) when oxy-firing. The dry flue gas was to be provided by the CPU, when the CPU was in service, and was to be stored locally in the pulse gas receiver. During air-fired operation or when the CPU was not in service, dry compressed air was to be used to clean the filter bags. In both cases, the compressed gas would have entered the bag from the top via the blow pipe. The air or gas pulse would have expanded the filter bag and released collected dust cake on the outside surface of the filter bag.

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

3.4.16 Byproduct Solids Recirculation and Handling

The fabric filter hoppers were to collect solids that fall out of the flue gas stream or were discharged from the filter bags above. At the outlet of each hopper, one roller control gate would have modulated to control the flow of solids back to the CDS inlet via recirculation slides. The recirculation slides were to use clean flue gas or air for the conveying medium, depending on the operating mode. The clean flue gas was to be pulled from the flue downstream of the primary gas reheater and recycle damper but upstream of the PR fan. When in oxy-fired mode, clean flue gas that was of the same composition of that going to the CPU, was to be used for conveying. When in air-fired mode, air pulled from this same flue was to be used for conveying and the transition from air to flue gas would have occurred automatically as the primary stream was transitioned from air to recycled flue gas with oxy-firing.

Each of three (3) hopper discharge recirculation slides would have fed a longer recirculation slide that was dedicated to one side of the PJFF. At the CDS vessel, this long recirculation slide was to be split into two smaller recirculation slides; one (1) per venturi. See Figure 3-20, below, for a model image showing the routing of the recirculation slides from the PJFF hoppers into the CDS. The continuous flow of solids returned to the absorber would have helped maintain a sufficiently high solids density in the absorber. This was important for the absorption process as the humidification of the gas stream would depend, in part, on the large surface area of solids present. Continuous recirculation of byproduct solids would also have helped increase the hydrated lime utilization.

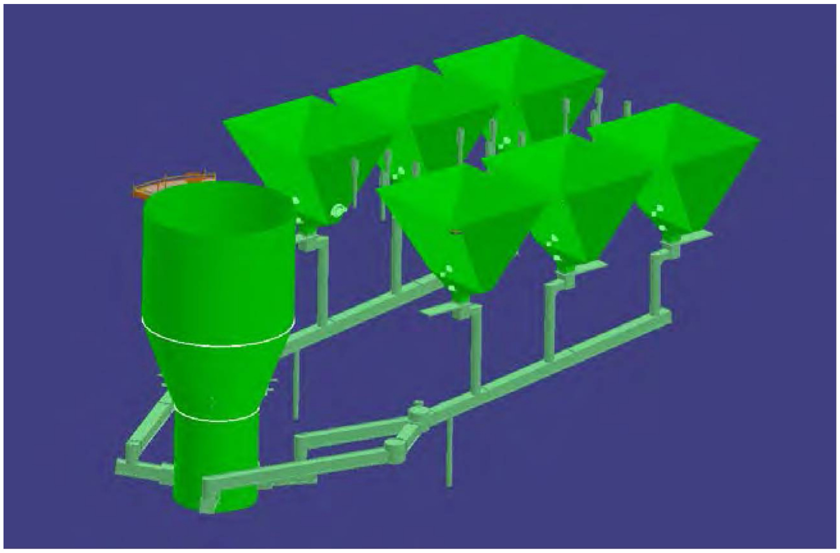


Figure 3-20: Byproduct Recirculation Slides

3.4.17 Byproduct Removal System

From the continuous removal of acid gases, the inventory of byproduct solids in the fabric filter hoppers would have increased. A conventional pressure pneumatic handling system was to have conveyed a portion of the recirculation solids to the Byproduct Solids Storage Silo. The pressure system was to consist of airlocks, positive displacements blowers, and piping designed to convey the byproduct solids. The byproducts were to be removed from the recirculation slide via an opening on the bottom of the slide that allows solids to enter a rotary feeder. From the feeder the solids drop into a byproduct bin. The byproduct bin would have allowed for some temporary storage of byproduct solids for increased reliability. The byproduct bin was to have discharged into the airlock and solids were to be pneumatically conveyed to the Byproduct Solids Storage Silo as they dropped from the airlock into the conveying line. A single conveying line with pickup points at each of the two airlocks (side A and side B) was to be used.

The byproduct solids storage was to consist of a storage silo complete with bin vent, a silo discharge fluidizing air system including two (2) 100% byproduct storage silo fluidizing air blowers (one (1) operating and one (1) spare), two (2) 100% capacity byproduct storage silo fluidizing air heaters and two (2) 100% capacity pugmill mixer unloaders. Refer to Figure 3-21 for a model and schematic of the byproduct storage silo and stack-up equipment.

The silo was to be sized to hold enough byproduct solids to maintain approximately seventy-two (72) hours of system operation when in the oxy-firing mode and burning the coal that produces the typical byproduct quantity.

The stored byproduct in the presence of moisture, if settled, would have had a tendency to harden. To maintain a fluid state, the silo was to have incorporated a heated fluidizing air system. The air discharged from either fluidizing air blower was to have passed through a fluidizing air heater before it was distributed to the silo cone by way of flexible hose assemblies. Each hose assembly was to be equipped with a manual valve and check valve for isolation.

The byproduct was to be wetted using either DCCPS cooling tower blowdown water or treated CPU condensate to achieve approximately a 20%-30% by weight moisture content in the ash. This would have eliminated the possibility of dusting when the ash was loaded into trucks for disposal.

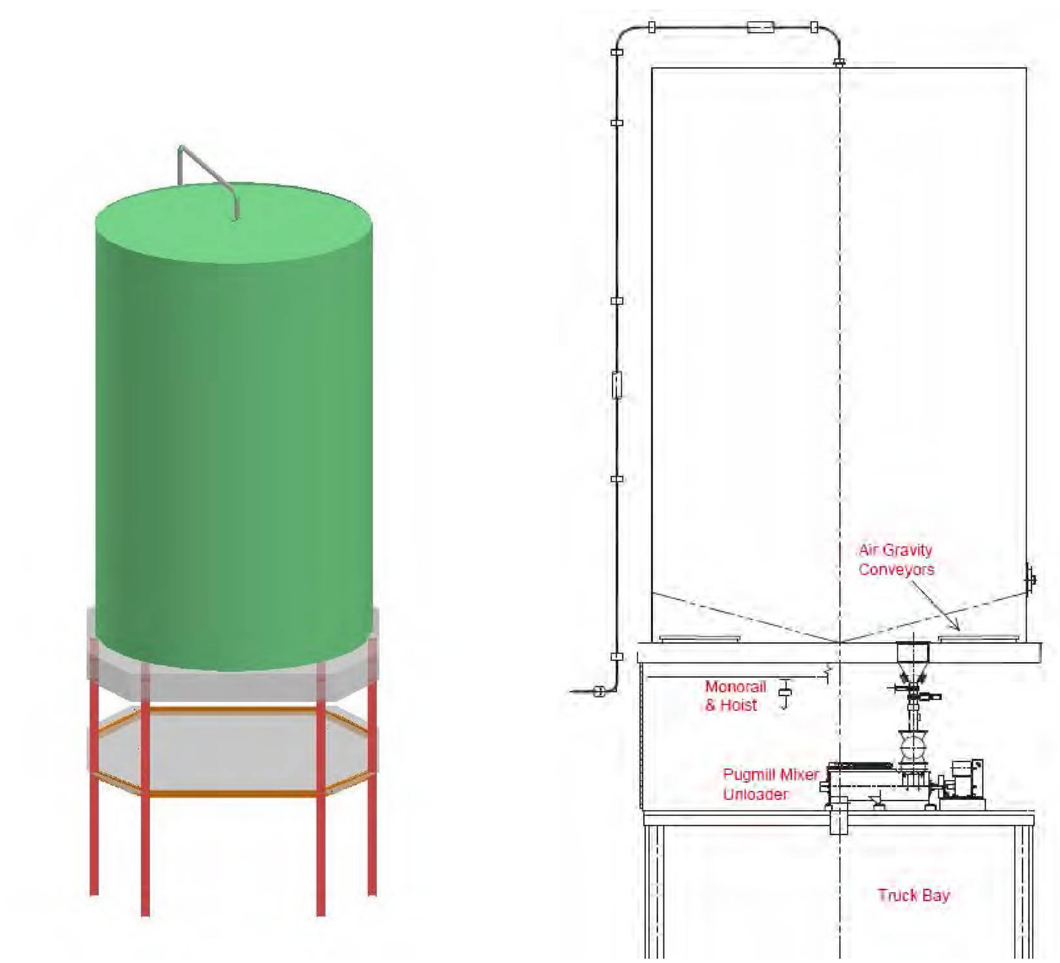


Figure 3-21: Byproduct Storage Silo and Appurtenances

3.4.18 Direct Contact Cooler Polishing Scrubber (DCCPS)

The dehumidification system was to be comprised of a DCCPS and a dedicated wet cooling tower (part of the BOP scope). Two (2) 100% capacity DCCPS blowdown pumps (one (1) operating and one (1) spare) were to have sent reaction tank liquor to the cooling tower. Two (2) 100% DCCPS circulating water pumps (one (1) operating and one (1) spare) (BOP scope) would have returned cooled water from the cooling tower back to the DCCPS spray headers. Trona liquor reagent was to be added to the cooling water supply stream by the trona liquor feed pumps.

After removal of most of the SO_2 in the CDS absorber and PJFF, a portion of the flue gas was to be sent to the DCCPS. It was in this vessel that the flue gas was to be cooled below the adiabatic saturation temperature to condense water, and the flue gas SO_2 concentration was further reduced to about 1 - 2 ppm (dry). The 7.62 m (25 ft) diameter DCCPS vessel was to be constructed of 316L stainless steel. The bottom of the conical reaction tank was to be 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 was by the DCCPS blowdown pumps.

Figure 3-22: Typical Scrubber Internals (tray, spray level, mist eliminator with wash pipes)

The gas entering the DCCPS was to have passed through a perforated tray and then though three (3) standard spray levels which were supplied with cool liquor from the DCCPS circulating water pumps (see Figure 3-22). The tray, spray headers and supports were all to be constructed of 316L stainless steel. The absorber liquor was to be sprayed using stainless steel spray nozzles.

Above the spray headers, the scrubber was to be equipped with two (2) stages of stainless steel mist eliminators which were to have removed much of the carryover mist by inertial contact. The primary stage was for bulk entrainment (large droplet capture), while the secondary stage was to act as a polishing stage (wash water droplet and finer particle capture). This two-stage mist eliminator was to be kept free of deposits by using a dedicated wash water system. DCCPS water was to be 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 would have been washed, sequentially by section, to optimize the wash flow rate. The mist eliminator blades, wash water headers and spray nozzles were all to be constructed of stainless steel.

The dehumidified and polished flue gas was to exit the DCCPS and was to be sent to the primary gas reheater. The reheater would have raised the gas temperature to ensure that the water was sufficiently above the moisture dew point before entering the CPU and primary recycle fan. Downstream of the primary gas reheater, a portion of the flue gas was to be sent to the CPU, and the remainder to the PR fan.

3.4.18.1 Absorbent Feed - Trona

Sodium sesquicarbonate (unhydrated form of naturally occurring trona) was to be 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. This sodium based reagent was selected, rather than a lime based reagent, because it was soluble in water and would not have fouled the wet cooling tower. The trona would have reacted primarily with the SO_2, and produced sodium sulfate and sodium bisulfate as reaction products. Those reaction products would have steadily increased in concentration over time and therefore a blowdown stream would have been required to maintain an allowable steady state concentration of the dissolved solids in the DCCPS circulating liquor. This blowdown stream would have been sent from the DCCPS cooling tower to the DCCPS waste water treatment system (BOP scope).

Dry trona was to be truck delivered to the site and conveyed pneumatically via a self-discharging positive displacement blower on the truck to either one of two (2) 100% capacity trona filter receivers. Each filter receiver was to be equipped with a collection hopper, a 100% capacity rotary feeder, and a wetting box. Clean dry air was to be piped to the hopper to ensure the free flow of reagent into the downstream equipment. Refer to Figure 3-23 for a schematic of the Trona system stack-up equipment.

Both 100% capacity filter receiver/rotary feeder/wetting box assemblies were to be mounted on top of a common 6.9 m (22.5 ft) diameter trona liquor storage tank. The water added in the wetting box was to be adequate to make a 12.5% by weight solution of trona liquor in the storage tank. The storage tank was to have provided sufficient storage capacity for 1.5 truckloads, and was to be constructed of epoxy-coated carbon steel. The tank was to be equipped with an agitator to ensure the trona was completely dissolved 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 was to be added to the DCCPS tower using two (2) 100% capacity trona liquor feed pumps (one (1) operating and one (1) spare). The trona liquor feed line was to tie into the headers that enter the DCPPS. Since the reagent required during normal oxy-fired operation was minimal, the remainder of the feed liquor was to be recycled back to the storage tank to maintain a minimum allowable flow through the pump.

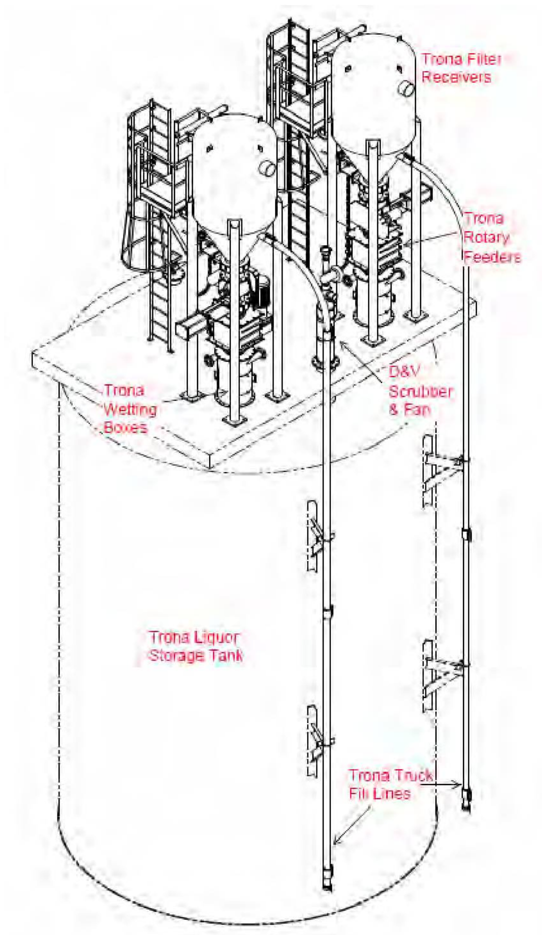


Figure 3-23: Trona Unloading, Dissolving, and Storage System

3.4.18.2 Air Infiltration

Air infiltration in the boiler/GQCS process would have impacted plant (aux power) and CPU performance. Over time, increasing air infiltration would increase flue gas flow through all GQCS equipment and the CPU, increase power consumption (ID fan and CPU) and, if excessive, limit load. If air infiltration was too high, it could have increased the flow to the CPU compressor to the point where it reached its flow limit, and either the firing rate would have had to be reduced to stay within the maximum gas flow, or the unit would have to be shut down to seal leaks. If this limit was exceeded, the excess flow would have been discharged from the CPU vent and it would have been apparent that the flow capacity of the CPU had been exceeded.

This limit was volumetric and was a function of mass flow, temperature and pressure. The flue gas pressure could not have been varied to any significant extent. Reductions in temperature would have provided a more noticeable impact and might have been achieved, at least temporarily, by:

- Reducing the gas reheater temperature rise to reduce gas temperature to the CPU and/or
- Increase the cooling in the DCCPS. The extent to which additional cooling might have been achieved depends upon ambient conditions and cooling tower capacity and would result in additional water removal.

An allowance for a reasonable amount of air infiltration had been accounted for in the process and equipment designs. The quantity of air infiltration included in the process design was derived from known air uses within the process, leakages obtained from equipment vendors, experience, and consideration for some increase due to aging.

To minimize air infiltration, the following steps have been taken:

1. The process design was arranged to minimize the amount of equipment operating below atmospheric pressure (see Figure 3-24). To minimize the equipment subject to air infiltration, the boiler pressure balance point had been relocated from the upper furnace to the recycle heater inlet. This also would have reduced the driving pressure difference by about 6 in wg in the sub-atmospheric pressure region. As a result, only the equipment and flues between the recycle heater and the ID fan inlet were subject to air infiltration.

2. To ensure the equipment was as tight as possible, B&W was requiring special quality control and leak testing during fabrication and construction. All welds for flues, ducts, and for the flue gas components between the recycle heater and ID fan inlet were to be visually inspected and signed off. In addition to visual inspection, non-destructive testing, using a liquid penetrant, was to have been used. Access doors between the recycle heater and the ID fan inlet were to be vacuum box tested.

3. The equipment specifications for fan inlets and shaft seals, damper shaft seals, expansion joints, and gaskets were to have incorporated requirements necessary to help minimize leakage. The access door designs had also been modified to better ensure that a tight seal was achieved.

4. The sealing medium for the pulverizers (except yoke seals), and boiler sealing (except scanner cooling, sootblower sealing and observation door aspiration) would have passively transitioned from air to clean flue gas, taken after the DCCPS, as the unit transitioned from air firing to oxy-mode operation.

5. CDS solids fluidization medium would have passively transitioned from air to clean flue gas, taken after the DCCPS, as the unit transitioned from air firing to oxy-mode operation.

6. The PJFF pulse cleaning system was to have been transitioned from air to clean dry flue gas, provided by the CPU, after the transition to oxy-firing.

Should the air infiltration have increased to the level that it significantly impacted performance, maintenance of the flues and equipment in the sub-atmospheric region would have been necessary.

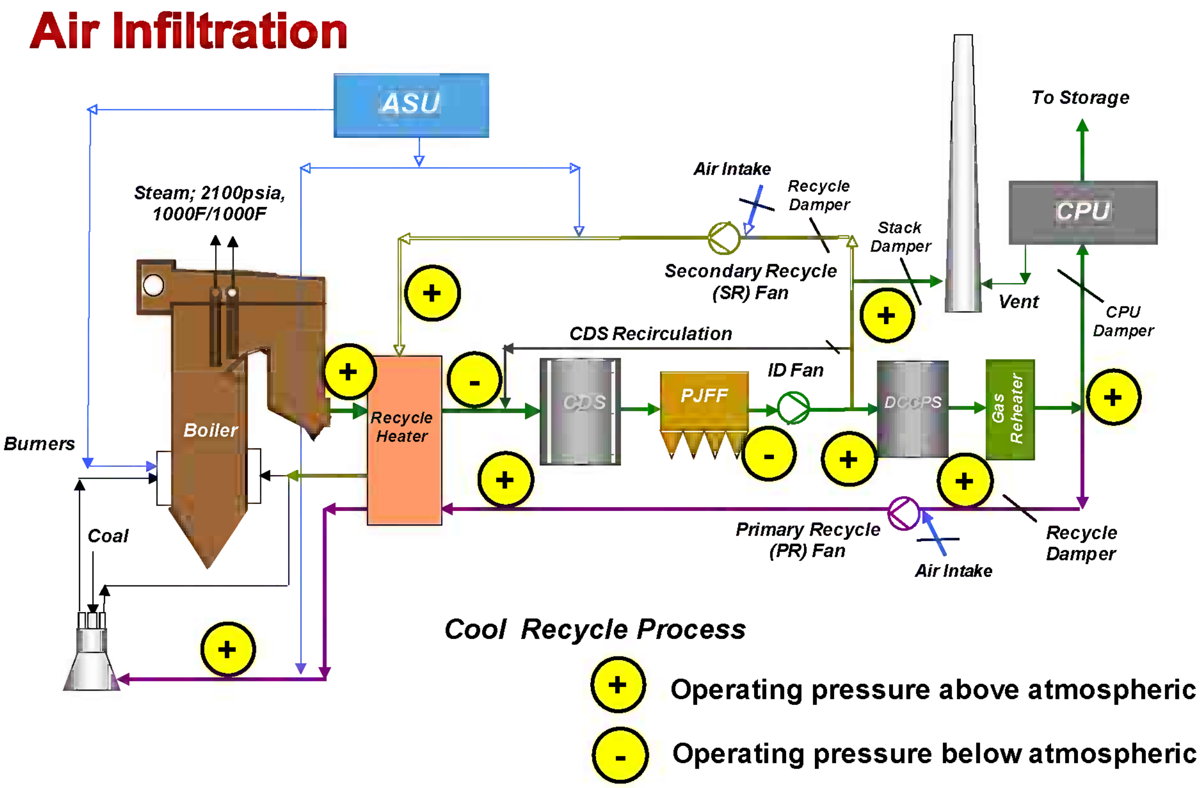


Figure 3-24: Air Infiltration Region

3.4.18.3 Flue Gas Leakage

Leakage of flue gas out of the process was also minimized for the following reasons:

- It poses a health hazard if breathed in concentrated form
- Loss of a significant amount of CO_2 would have affected capture performance defined as:
  CO_2 captured (%) = CO_2 sent to the pipeline ÷ CO_2 produced by combustion

Flue gas from oxy-combustion would have differed from 'normal' flue gas from conventional air-fired combustion in two fundamental ways; its molecular weight was 30-38% higher, and the concentration of CO_2 was much higher (as high as 76.5% versus about 14% for 'normal' flue gas).

Comparing oxy-combustion flue gas to "normal" flue gas at the same temperature and pressure, oxy-combustion flue gas density would have been higher due to its higher molecular weight. Therefore, it would have had a greater tendency to sink and possibly become trapped in low lying areas such as basements or sumps (note that "normal" flue gas is also slightly heavier than air at the same temperature and pressure, so this is not a completely new concern with oxy-combustion). To minimize potential hazards, low areas have been avoided where conditions conducive to possible flue gas entrapment exist, and there were no basements in the boiler or GQCS areas. Sumps would not normally be a concern, as they would be filled with liquid, but these and any other low areas requiring access for maintenance would have been considered 'confined spaces' and the environment tested using a handheld monitor before entry.

Secondly, a high concentration of CO_2 would have presented an additional concern. Both 'normal' and oxy-combustion flue gases generally had very low oxygen content, only 2% to 4% oxygen, which would have resulted in asphyxiation, if breathed. Both might also have contained other constituents, such as sulfur compounds, at concentrations that could be a health hazard if breathed. However, even if the minor constituents were at safe levels and there was sufficient oxygen to breathe, above about 20% by volume, the CO_2 concentration in both 'normal' and oxy flue gas was of concern. 'Normal' flue gas contains about 14% CO_2 by volume, which was 140,000 ppm while the CO_2 concentration in oxy flue gas might have been as high as 76.5% by volume wet or 765,000 ppm. According to OSHA, the 8-hour exposure average limit was 5000 ppm and the Immediately Dangerous to Life and Health (IDLH) limit was 40,000 ppm. When inhaled, a high CO_2 concentration inhibits CO_2 transfer from the blood into the lungs resulting in CO_2 retention (hypercapnia) which could be fatal.

As in any coal-fired power plant, the following precautionary measures would have been taken:

1. Minimize low-lying areas where flue gas could be confined
2. Minimize flue gas leakage from flues and equipment (the same preventative measures have been taken as for air infiltration)
3. Provide normal ventilation for enclosures / buildings containing flue gas or CO_2 conveyances
4. Purge the gas path with air before entering for maintenance
5. Check oxygen and CO_2 levels whenever entering or working in a confined space

Flue gas only leaks from equipment operating above atmospheric pressure. To minimize flue gas leakage, the same leakage prevention measures taken to prevent air infiltration in the sub-atmospheric pressure regions would also have been applied in the positive pressure areas (see Section 4.4.18.2, Air Infiltration).

3.5 Air Separation Unit (ASU)

3.5.1 Overview

The ASU was to have been an integrated component of the oxy-combustion power plant facility. This ASU was to have supplied oxygen for the boiler island with the process simply illustrated in Figure 3-25. A typical ASU arrangement is shown in Figure 3-26.

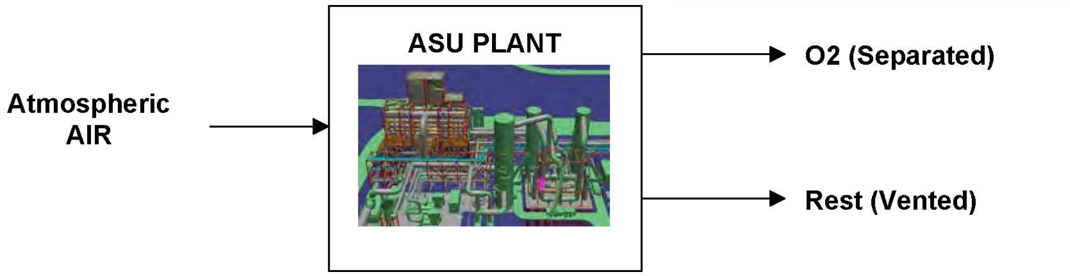


Figure 3-25: Basic Air Separation Process

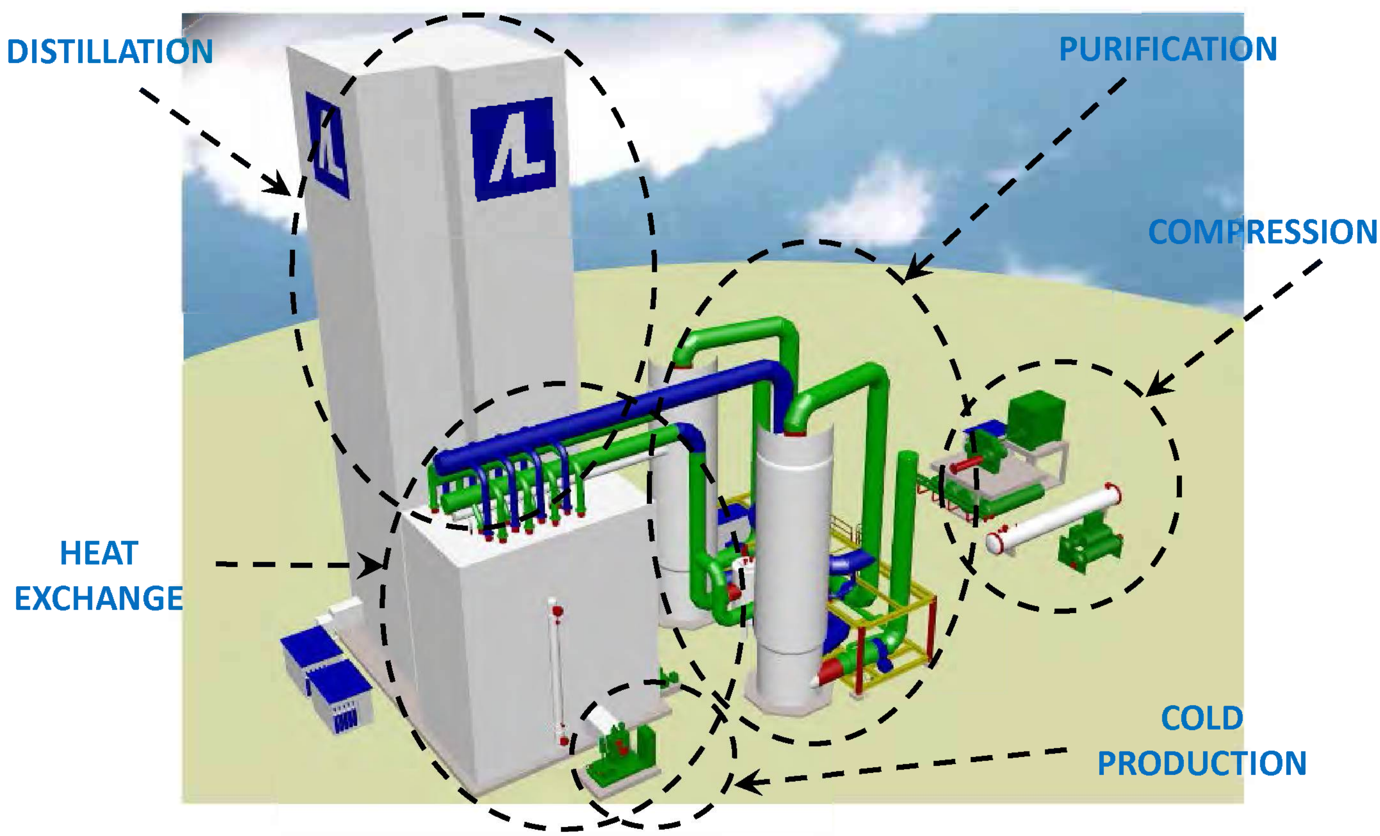


Figure 3-26: Typical ASU Arrangement

3.5.2 Process Description

The ASU design for the FutureGen 2.0 Project was strongly optimized for the oxy-combustion application. In addition to using equipment technologies similar to a conventional ASU, the same core process was to have been implemented, .i.e., compressors, purification, pre-cooling, columns (see Figure 3-27). The difference for the FutureGen ASU process design was the use of a proprietary low energy ASU scheme with heat integration between the ASU and BOP, the use of low delta pressure equipment, and the optimized design of the cold box equipment arrangement (see Figure 3-28).

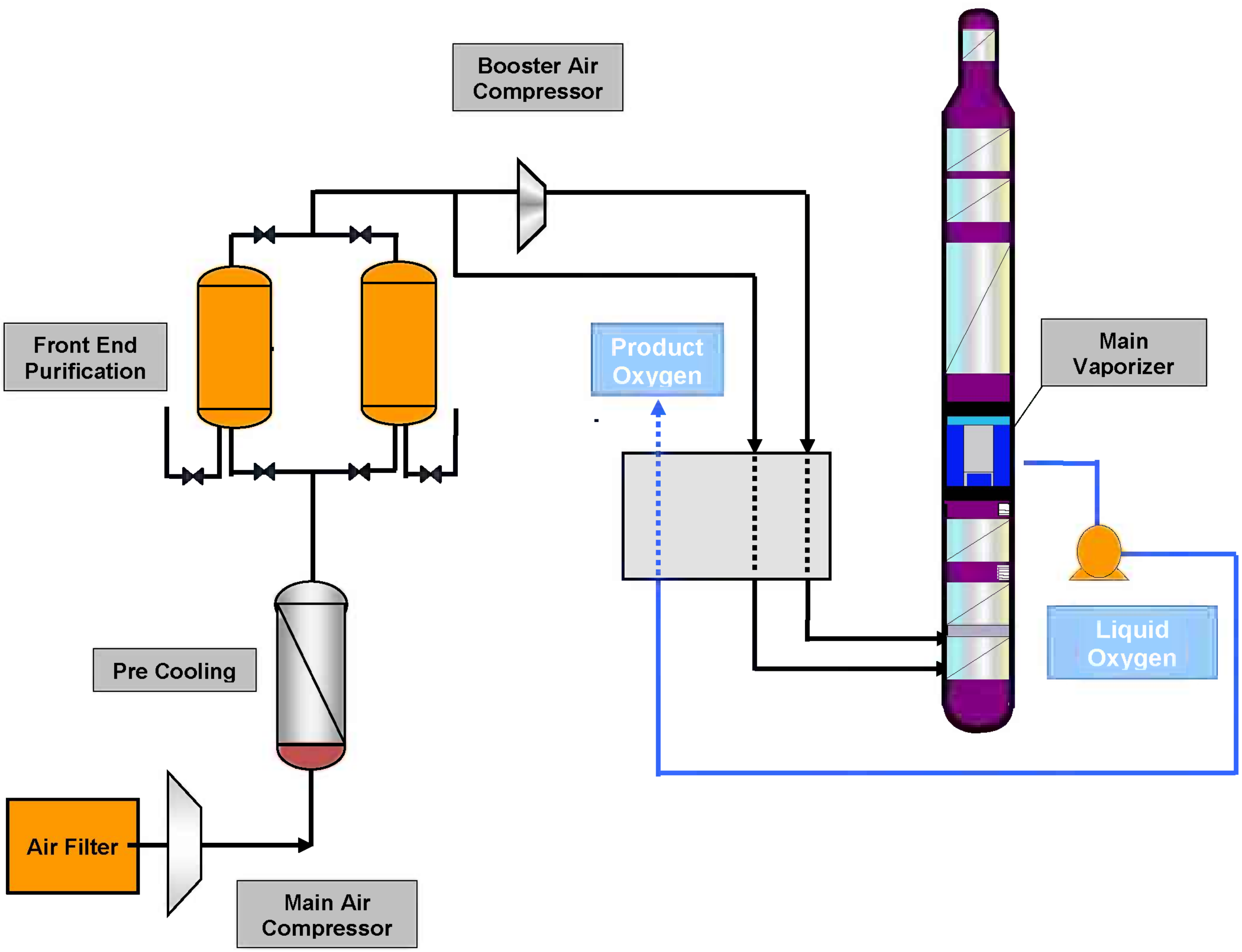


Figure 3-27: Typical ASU Core Process Equipment

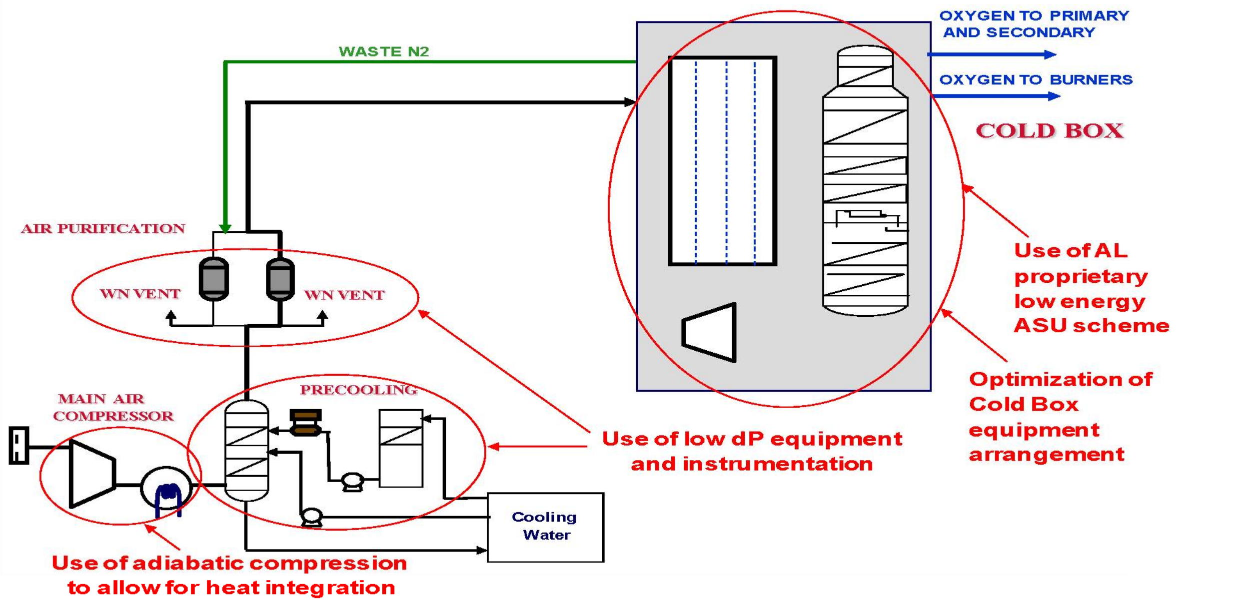


Figure 3-28: Typical ASU Flow Diagram and Process Description

Figure 3-29: 3900 mtd ASU

3.5.2.1 Air Compression and Air Pre-Cooling

Atmospheric air was to have been the source of raw material for the ASU, the main components being oxygen and nitrogen.

Atmospheric air was to have been drawn through the inlet air filter to remove particulate matter before entering the suction of the Main Air Compressor. The essentially particle-free filtered air was to be compressed in the electrically driven Main Air Compressor (see Figure 3-30).

The heat of compression from this compressor was to be transferred to boiler feed water in the air/BFW heater. The air was to be further cooled in a 2-stage direct contact cooler. The top stage uses chilled water from the nitrogen/water tower and the bottom stage uses cooling water.

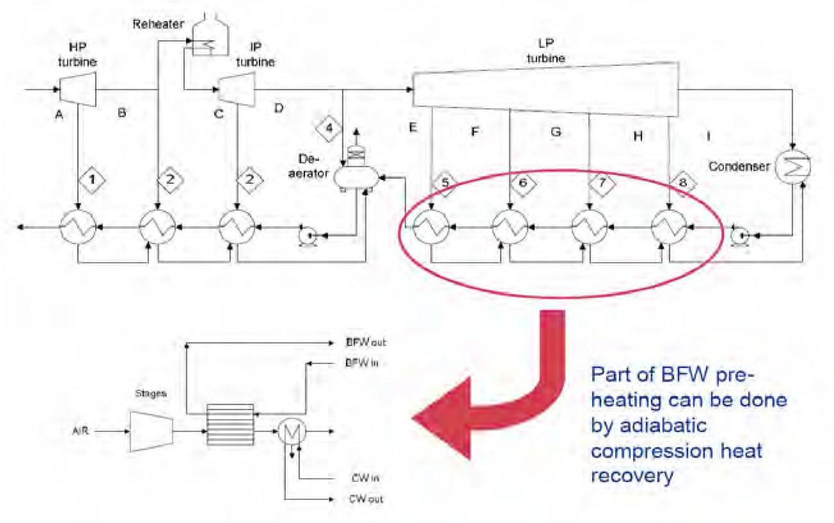


Figure 3-30: Air Compression and Air Pre-cooling

3.5.2.2 Air Purification

The cold air enters a front-end temperature swing adsorption (TSA) purification system to remove moisture, carbon dioxide, and other impurities. The system was to be composed of two radial flow bed vessels containing activated alumina and molecular sieve adsorbents. Waste nitrogen, heated by low-pressure steam in a reactivation heater, was to be used to regenerate the adsorbents.

3.5.2.3 Adsorber Design

The Front End Purification (FEP) system was to be comprised of a dual bed (successive layers of alumina and molecular sieve) air purification system. First, it removes the water. Water, even when pure, quickly degrades the efficiency of the molecular sieve in stopping carbon dioxide (CO_2). The activated alumina bed, located upstream, very effectively protects the molecular sieve bed. Unlike the molecular sieve, activated alumina was durable and well suited to stop water. Its mechanical strength was almost unaffected by the presence of liquid water. Activated alumina would also have been more resistant than molecular sieves to acids that might have been created with the moisture and contaminants present in the incoming air.

For ASUs with higher capacities, as in the case for FutureGen, the principle of the radial-flow (see Figure 3-31) dual concentric bed system had been chosen because of its following major advantages.

- Reduced pressure drop, resulting in increased efficiency. The ASU design allows for reduced but consistent depth of bed (molecular sieve and activated alumina), allowing for reduced overall pressure drop through the system.

- Increased air purification capacity per vessel in comparison to traditional bed technologies
- Smaller footprint
- This design also integrates a maintenance-free internal particulate filter

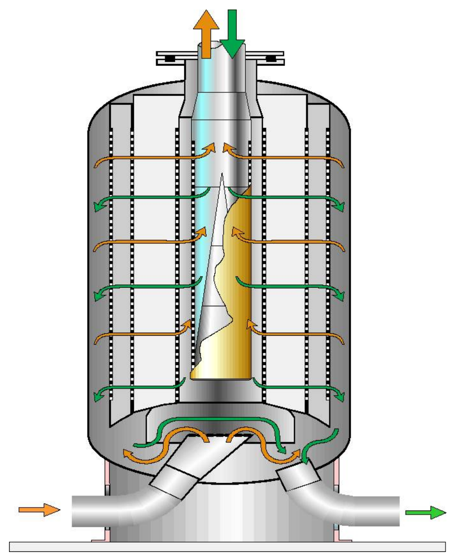


Figure 3-31: Typical Radial Flow Adsorber

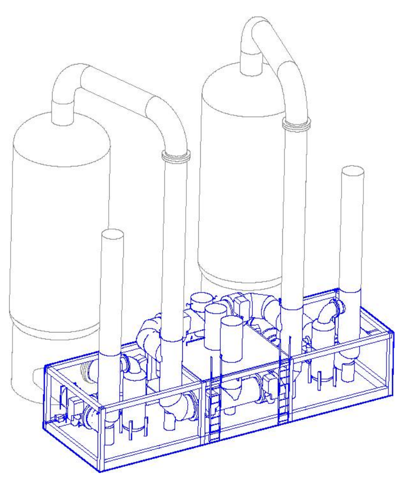


Figure 3-32: Typical Air Purification Switching Valve Skid

3.5.2.4 Cryogenic Process

The dry compressed air would have entered the distillation sections where it was separated into liquid oxygen (LOX) and gaseous waste nitrogen.

The main equipment for this cryogenic section was:

- Separation Pressure Vessels
- Distillation Columns

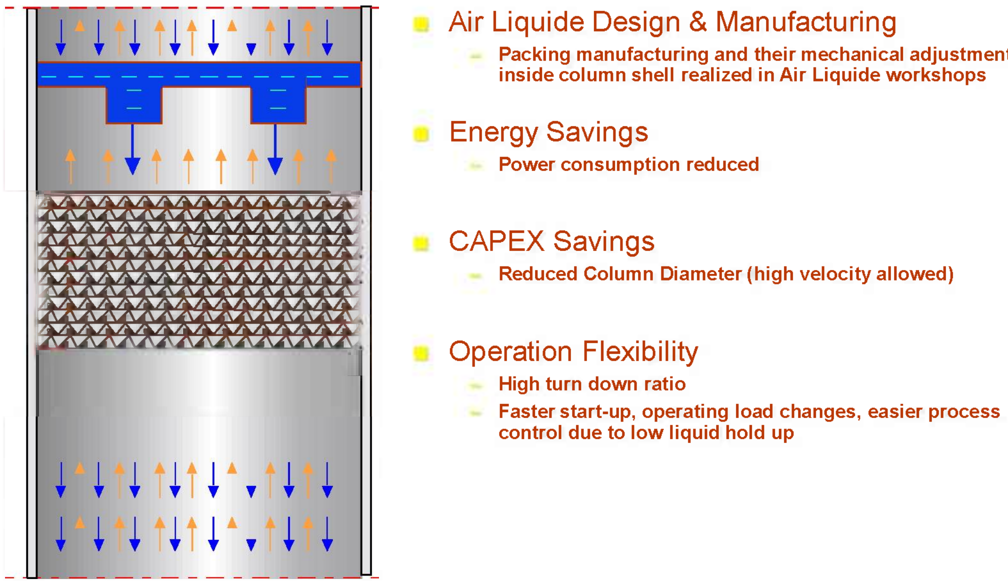


Figure 3-33: Distillation

- Aluminum Brazed Heat Exchangers

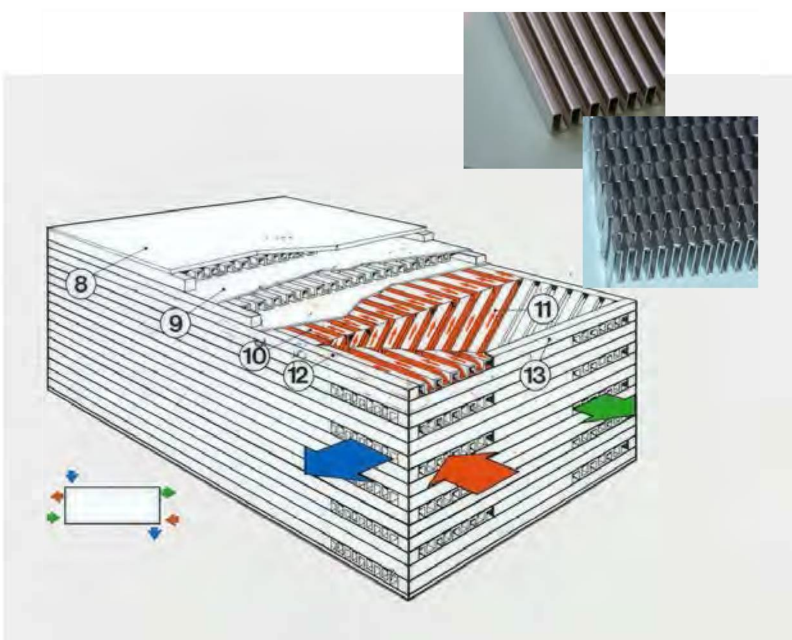


Figure 3-34: Typical Brazed Aluminum Heat Exchanger

- Cryogenic Centrifugal Pump

Figure 3-35: Typical Cryogenic Centrifugal Pump

- Expander Skid

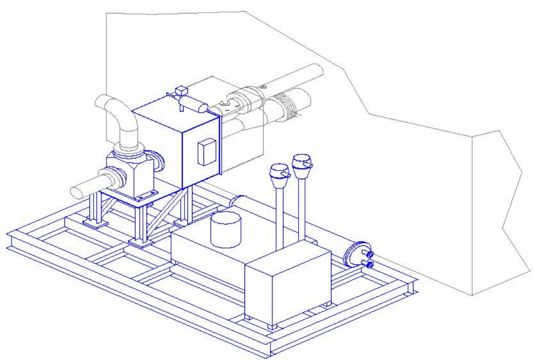


Figure 3-36: Typical Expander Skid with Cold Box

3.6 CO_2 Compression and Purification Unit (CPU)

3.6.1 Overview

The CPU was to have been an integrated component of the oxy-combustion power plant facility. Its function was to take low pressure (~1atm) acceptable (requisite purity, pressure, temperature, etc.) flue gas from the GQCS and to compress and purify it for delivery to the pipeline for subsequent transport and storage.

The CPU process concept is simply illustrated in Figure 3-37.

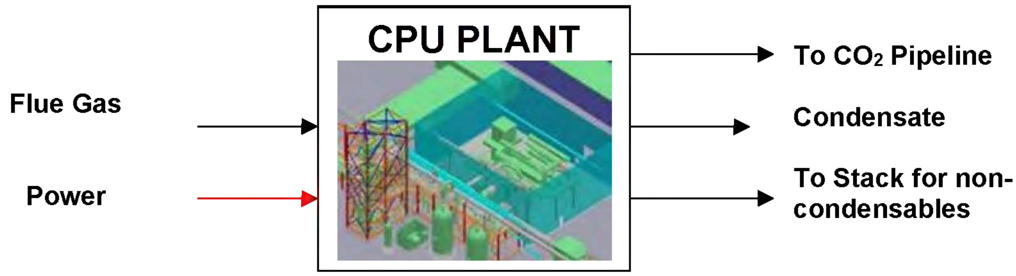


Figure 3-37: Basic CO_2 Compression Purification Process Concept

3.6.2 Process Description

3.6.2.1 Overview

The FutureGen 2.0 CPU process was divided in four main blocks (see Figure 3-38):

- The flue gas compression and drying (also called *warm part* of the CPU) where flue gas was to be pre-treated, compressed and dried
- The cryogenic separation (also called *cold part* of the CPU) where the main impurities (also called *non-condensable* gases: O_2, Ar & N_2) were to be separated from the CO_2
- The CO_2 product compression where the pressure of the CO_2 was to be increased up to the pipeline pressure
- The non-condensable gases treatment where the exhaust gases from the cryogenic part were to be further purified to reduce pollutant emissions to the air

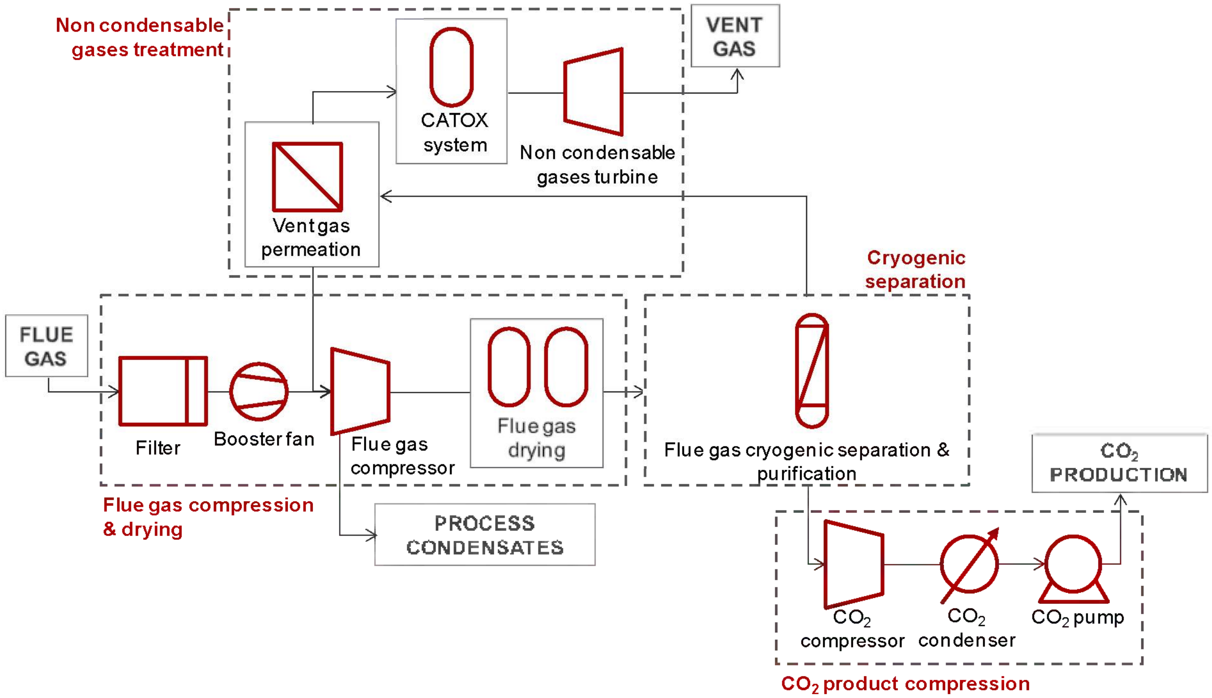


Figure 3-38: FutureGen 2.0 CPU Block Flow Diagram

3.6.2.2 Low Pressure Pre-Treatment

After exiting the DCCPS and the associated reheater, the flue gas was to pass through a mechanical filter to reduce particulate matter to the very low level of particulate matter required to avoid fouling and abrasion of the downstream centrifugal blowers, compressors, and other process equipment.

3.6.2.3 Flue Gas Compression

A booster fan was to have controlled the pressure in the upstream equipment DCCPS, reheater, and filter). The flue gas was then to have been compressed in a multistage, integrally geared, centrifugal compressor to the pressure required by the cryogenic process. Centrifugal, integrally geared machines are the most suitable technology, in terms of cost and energy efficiency, to compress the very large volumes of flue gas required in oxy-combustion applications.

The flue gas compression was also a key step for the abatement of impurities in the CPU, removing a significant portion of the NO_X as nitric acid in the process condensates captured in the interstage coolers. Most of the remaining SO_X was also to be captured in these process condensates.

3.6.2.4 Medium Pressure Pre-Treatment

Before entering the cryogenic process, the pressurized flue gas was to be dried to avoid water freezing in the cryogenic sections, as well as to achieve pipeline moisture requirements. The chosen adsorption drying system was to be based on a design that had been successfully tested at the Lacq and Callide Pilot Plants, and would have consisted of a two bed Temperature Swing Adsorption (TSA) unit. The flue gas would have been dried in one vessel while the other was regenerated.

3.6.2.5 Cryogenic Section

Dry flue gas was to have entered the cryogenic section where it was to be purified, separating non-condensable gases like N_2, Ar, CO and O_2 from the CO_2.

The process was based on partial condensation (the main part of the CO_2 entering the cryogenic section was to be liquefied, while most of the non-condensable gases would have remained in the gaseous state) and distillation.

The main equipment for this cryogenic section, packaged into two cold boxes, were:

- Separation pressure vessels
- Distillation columns and associated piping
- Compact type multi-fluid Aluminum Brazed Heat Exchangers

Figure 3-39: Example of Cryogenic Distillation Column Before Transportation

Aluminum Brazed Heat Exchangers (BAHX) have been developed specifically for the multi-fluid heat exchange needs in industrial gas applications, such as cryogenic air separation or CO purification in Synthetic Gas streams for the chemical industry. This compact technology would have been particularly well suited in terms of footprint, cost, and heat exchange efficiency.

3.6.2.6 Membrane Permeation for Increased CO_2 Recovery

The non-condensable gases exiting the cryogenic section were then to have been processed through a membrane unit where most of the uncondensed CO_2 was to be recovered back into the CPU flue gas compression chain.

The membrane technology was to utilize advanced hollow fibers in a proprietary process owned by Air Liquide and manufactured by its membrane division, MEDAL™.

Figure 3-40: Example of MEDAL™ Membranes Arrangement (Biogas Application)

3.6.2.7 Catalytic Oxidation for CO Removal

After membrane permeation, the pressurized non-condensable gas was to be subjected to catalytic oxidation, where CO was to have been oxidized to CO_2 with the oxygen already present in the gas.

3.6.2.8 Non-Condensable Gas Expansion

Lastly, the energy contained in the high pressure non-condensable gases was to be recovered by allowing them to expand through a turbine before they were vented to the atmosphere. In order to minimize cost and footprint, one turbine train treating 100% of the non-condensable gases was chosen.

3.6.2.9 CO_2 Product Pressurization

The purified CO_2 product from the cryogenic section was to be further compressed to a pressure sufficient to enable a significant increase of its density by cooling. Ambient air was to be used as the cooling media. Dense CO_2 product was to be boosted to pipeline pressure using a pump.

3.6.2.10 CO_2 Transfer to the Pipeline

Supercritical CO_2 at the conditions specified in Table 3-5 was to be delivered to the underground pipeline interface point (300 mm [12”] nominal) located near the east boundary of the Meredosia Plant. An isolation valve was to have been 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 was to have been managed by the Meredosia Plant, but operation of the CPU and the isolation valve was to have been a coordinated effort with the downstream pipeline and CO_2 storage site operator.

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

During operation, if CO_2 conditions did not meet the required specifications per Table 3-5, the plant would have notified the CO_2 storage site operator and a decision would have been made as to whether the process upset could be accommodated or whether flow to the pipeline would be stopped. No specific allowance for out-of-spec CO_2 was provided for in the CO_2 off-take agreement, but minor upsets would have likely been accommodated by the CO_2 storage facility, since they were to be diluted by the CO_2 inventory already in storage.

During CPU startup, shutdown, or other operating condition when the pipeline isolation valve was shut and no CO_2 delivery to the pipeline was occurring, CO_2 was to be discharged via the main stack CPU flue until pipeline deliveries could resume.

Additional monitoring and reporting requirements were to be developed and finalized during Phase III.

3.6.3 CPU Development Roadmap

AL has been actively involved in the development of oxy-combustion technologies for power generation with carbon capture for the past 10 years. AL has become a major participant and was involved in several key projects in the field, including the FutureGen 2.0 Project. An ambitious roadmap for bringing oxy-combustion technology for carbon capture to commercialization was to be executed (see Figure 3-41). The roadmap was aimed at improved CPU design with respect to three key criteria:

- Risk mitigation for first industrial demonstrations
- OPEX reduction (particularly via specific energy reduction)
- CAPEX reduction

After initial phases of lab-scale tests, process development and then pilot tests, AL had completed CPU design for the FutureGen 2.0 Project, integrating results from pilot plant testing.

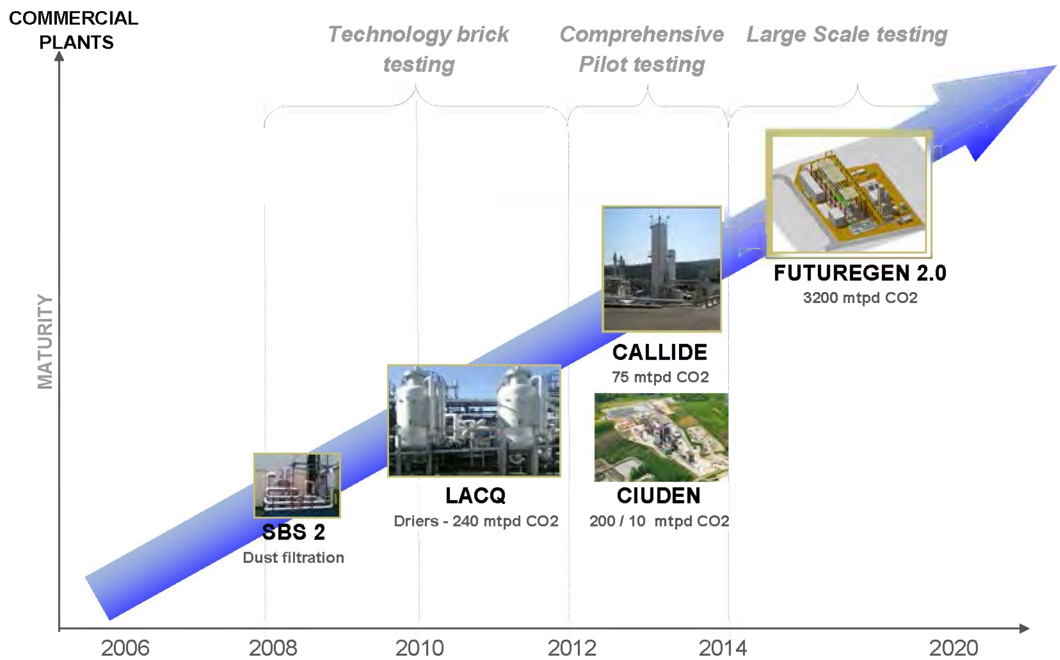


Figure 3-41: Overview of AL CPU Development Roadmap

3.6.3.1 High Performance Dust Filtration Pilot

AL had installed a pilot for testing high performance dust filtration technology at a Babcock & Wilcox test center in the United States (see Figure 3-42). Advanced dust filtration technology was tested on real flue gases from different boiler types. This system was operated in 2009 and had provided promising results. The Callide and CIUDEN Pilots have also tested high performance dust removal, building on the testing already completed.


Figure 3-42: AL High Performance Dust Filtration Test Skid

3.6.3.2 Lacq Pilot

The Lacq Project was the first complete pilot of oxy-combustion with carbon capture, transport and storage. CO_2 was captured from a 30 MWth natural gas oxy-combustion boiler at TOTAL's Lacq site. AL provided the ASU, proprietary oxy-burner technology and a flue gas drying unit. Once the CO_2 had been dried and compressed it was transported by pipe to injection in a depleted gas field.

The dryers (Figure 3-43) were specifically designed for the oxy-combustion application. Therefore, the tests being carried out on the dryer units were of particular importance for the development of the CPU design. Furthermore, the FutureGen 2.0 CPU was to have used the same design for the dryers, upscaled accordingly.

After more than 12,000 of hours of operation between 2010 and 2013 with various regeneration gases and NOx content in the feed gas, the tests enabled results to be obtained regarding:

- Adsorbent qualification (ageing, performance)
- Study of emissions throughout cycle
- Vessel materials qualification

Figure 3-43: Lacq Dryers

3.6.3.3 Callide Pilot

Located in Queensland, Australia, the Callide Project was a retrofit of a ~100 MWth boiler (~30 MWe) to oxy-combustion. AL provided two 330 tpd O_2 Air Separation Units and one 75 tpd CO_2 CPU. It was the largest oxy-coal pilot project worldwide.

AL, through this test platform, had demonstrated the whole oxy-coal flue gas compression and purification chain based on the downscale of a large commercial unit. Key design features included:

- Centrifugal compressors for the flue gas compression
- Brazed aluminum heat exchanger in the Cold Box
- High Performance dust filtration cartridges

The Callide CPU was also a strong reference, providing feedback from more than 3,000 hours of operation of the warm section of the process and from more than 1,800 hours of operation of the cryogenic part of the process.

The corrosion, the ageing phenomena and the behavior of impurities (H_2O, Particulate matter, SO_X, NO_X, Hg and CO) had been studied throughout the process by Air Liquide.

SO_X, mercury and particulate matter abatement have reached or exceeded expectations with the quench and scrubbing towers and with the high performance filtration device. The water removal was in accordance with the moisture specification for the cryogenics system downstream. The CO_2 mapping had been performed and had shown a CO_2 recovery of the cold part of the process of 87% and a very high CO_2 product purity (>99.9%vol.). The CO_2 recovery was slightly lower than the target of 90% due to unexpectedly high levels of air-ingress. As a result, special care was to have been taken regarding CO_2 recovery in the FutureGen 2.0 design.

One of the challenges of the CPU technology was the operation with CO_2 close to triple point conditions and the risk of freezing. This had been successfully demonstrated on the Callide Pilot Plant.

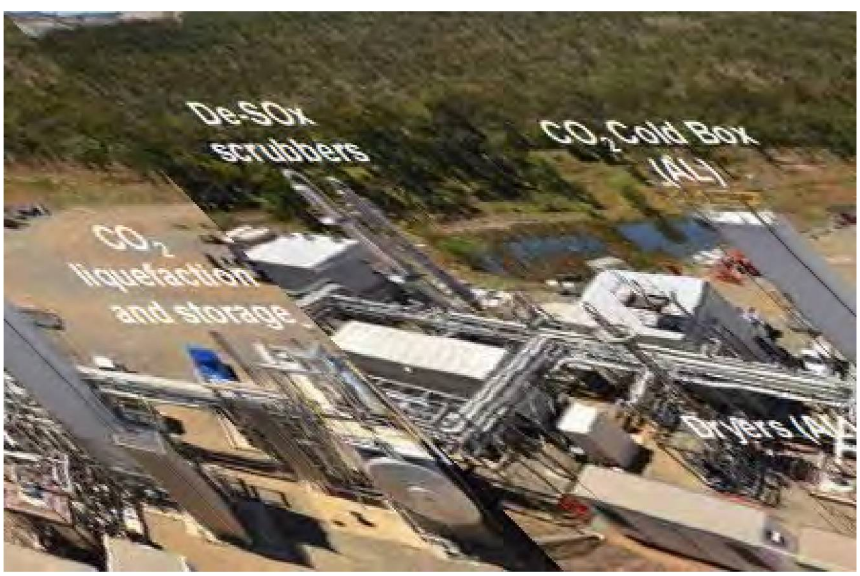


Figure 3-44: Callide Pilot Plant - Site View, September 2011

The CPU design for the FutureGen 2.0 Project was mostly based on technologies that were tested at Callide. In addition to using similar technologies, i.e., as centrifugal compressors and brazed aluminum heat exchangers to as great an extent as possible, the same core process was to have been implemented (see Figure 3-44). For example, an auto-refrigerated cycle was to be used for cooling the cryogenic part of the process on both projects. Differences between the FutureGen 2.0 Project and the Callide Pilot mainly stem from project specific constraints. For example, the Callide CPU did not include compression of the CO_2 product to supercritical pressure because the final product was liquid CO_2 for transport by truck. However, compression of pure CO_2 by centrifugal technology was already referenced in industry. Furthermore, some technological bricks were to have been added to the Callide process to build the FutureGen 2.0 scheme, such as membranes to enhance the CO_2 recovery of the CPU and a catalytic oxidization bed on non-condensable gases to drastically reduce the carbon monoxide emission to atmosphere.

3.6.3.4 CIUDEN Pilot

The CIUDEN platform was equipped with both a Pulverized Coal (PC) and Circulating Fluidized Bed (CFB) boiler, both capable of burning a range of coals.

The warm section of the process had an equivalent capacity of 160 tpd of CO_2 and the cryogenics section a capacity of 10 tpd of CO_2.

Commissioned in 2012, the CIUDEN CPU was the second pilot-scale reference for the qualification of the technology (see Figure 3-45). It had provided feedback from more than 2,500 hours of operation of the warm section of the process and from more than 1,500 hours of operation of the cryogenics part of the process. As at Callide, pilot equipment used technologies that would be used for large-scale industrial application.

The expected SO_X abatement had been reached in the quench and the scrubbing columns. The two columns also removed nearly 100% of the dust contained in the flue gas.

Low pressure drying had been successfully tested. Using a three vessel cycle and regeneration using dried gas, this innovative solution enabled use of inexpensive materials for dryers and for the flue gas compressor.

Concerning the cold section of the process, the following results were of particular note:

- No issues with CO_2 freezing despite operating close to the CO_2 triple point
- Very high CO_2 product purity (>99.9%vol)
- Very low NO_x and SO_x content in CO_2 product

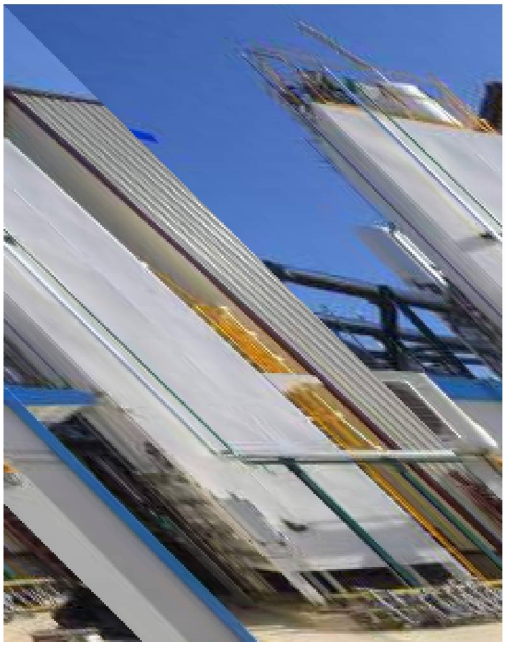


Figure 3-45: CIUDEN Pilot Plant - Cold Box

3.7 Steam Cycle and Balance of Plant Systems

In general, the design and configuration of the steam turbine power cycle is typical of a coal-fired Rankine cycle power plant designed in the late 1960s. As such, the following system descriptions provide a general overview of each major system. Typical system design details are not discussed at length unless unique to the design of the plant. The overall integration between the BOP steam cycle and the other islands is generally depicted on the steam cycle heat balance diagrams.

A detailed assessment of the existing plant equipment (Legacy Equipment), including the coal-based infrastructure from Units #1, #2, and #3, along with the site's common facilities, was completed by URS during Phase I to determine which existing components needed replacement or refurbishment to support the repowered oxy-combustion configuration of Unit 4. This section identifies existing plant components that would have been reused and those components that would have been replaced. Further details regarding the planned repair and upgrade for the Legacy Equipment are presented in Section 4.7.13.

3.7.1 Steam Systems

3.7.1.1 Main and Reheat Steam

The main steam system transports high pressure and high 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 auxiliary steam system. Existing steam piping systems within the Unit 4 turbine building were to have been reused.

The design pressure of the main steam system is equal to the lowest steam generator superheater safety valve set pressure. The maximum design pressure is 150.5 barg (2,180 psig). The design temperature corresponds to the steam generator MCR superheater outlet temperature of 540.6°C (1,005°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 new main steam piping was to be seamless ferritic alloy steel, SA 335, Grade P91. The existing main steam piping is seamless ferritic alloy steel, SA 335, Grade P22.

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. 3-6 high pressure feedwater heater and to the auxiliary steam system. The system was designed in accordance with the requirements of ASME 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 of 39.7 barg (575 psig). Design temperature corresponds to the maximum HP turbine exhaust temperature of 337 °C (638°F) plus a 16.7 °C (62°F) margin to account for steam turbine transient conditions. The material for the cold reheat piping was to have been ASTM A106, Grade B. The existing cold reheat piping material is ASTM A106, Grade B.

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 was designed in accordance with the requirements of ASME B31.1 rules for non-boiler external piping. System design pressure is equal to the lowest set pressure for the safety valves on the reheater inlet of 38.6 barg (560 psig). The design temperature corresponds to the steam generator MCR reheater outlet temperature of 540.6°C (1,005°F) plus a 5.6°C (10°F) margin added to account for the accuracy of the temperature control. Material for the hot reheat piping was to be seamless ferritic alloy steel ASTM A335, Grade P22. The existing hot reheat piping is seamless ferritic alloy steel, SA 335, Grade P22.

Other system design criteria for the new systems include:

- Piping sized for turbine generator maximum load case conditions
- Maximum velocity at full load 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

3.7.1.2 Extraction and Low Pressure Steam

The existing 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. This system was to have been extended to the relocated deaerator. The existing heater drain system was to have been reused.

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 260°C (500 °F) .

System components with design temperatures less than 399 °C (750 °F) were generally to be fabricated from carbon steel ASTM A106, Grade B, carbon steel. Components with design temperature above 399 °C (750 °F) were to be fabricated with 1 ¼% Cr ½% Mo alloy steel material, ASTM A335 Grade P11, or from 2 ¼ % Cr 1% Mo alloy steel material, ASTM A335 Grade P22.

The system was designed in accordance with the following criteria:

- Maximum velocity at full load conditions would not have exceeded 76 m/sec (15,000 ft/min) in extraction steam piping, except for extractions under vacuum, where velocity would not have exceeded 102 m/sec (20,000 ft/min)

Extraction steam piping design pressures and temperatures were to match the existing system design conditions on extraction piping to the deaerator. Extraction piping design temperature to the deaerator would have been increased by 50 °F. The existing piping to the deaerator would have been adequate for the temperature increase; however, the increased temperature would have exceeded the deaerator design temperature rating. Therefore, the deaerator nameplate temperature rating would have needed to be increased and would have required calculation review and additional inspections if the project was to be pursued in the future.

3.7.1.3 Auxiliary Steam

The auxiliary steam system takes steam from a new auxiliary boiler, main steam system, and cold reheat system, conditions it through pressure reducing and de-superheating stations, and provides lower 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
- Pulverizer inerting
- Process heating in the boiler, GQCS, ASU and CPU process islands
- Air heater soot blowing
- Boiler secondary air heating

An auxiliary boiler was to be implemented for startup.

The existing Unit 4 auxiliary steam system for glycol heating, fuel oil heating, and building heating was not to be reused.

The new auxiliary steam supply header was to have been designed for steam at 14.5 barg (400 psig) and 204 °C (650 °F). Pressure and temperature limitations for the auxiliary steam users listed above would have required additional pressure regulation and de-superheating.

3.7.2 Steam Turbine Generator

3.7.2.1 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. For the repowered oxy-combustion configuration, the turbine was to have been operated at approximately 85% of its original design kW rating. 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 was to have been modified to a hybrid sliding pressure operating mode. When operated in the oxy-combustion mode at full load, the six (6) turbine throttle valves would have been at their wide-open position for maximum efficiency. The sixth valve was to be throttled to allow more rapid load-following, down to approximately 90% of full load, resulting in less efficient operation.

The turbine provides for six (6) feedwater heater extraction points. Final feedwater temperature at the turbine original design rating 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.

3.7.2.2 Steam Turbine Auxiliaries

Major turbine auxiliary systems and components include the following:

Gland Seal System

The existing 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 two (2)100% capacity motor-driven exhausters. A new gland steam electric superheater was to have been provided for steam temperature matching during warm and hot starts.

Lubricating Oil System

Turbine bearings are lubricated by the existing 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, two (2) 100% capacity water-cooled lube oil coolers, a vapor extractor, oil purifier and duplex oil filter.

Turbine Governor System, Hydraulic Oil System, and Trip System

The existing 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, two (2)100% capacity 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. The existing hydrogen storage and supply system was to have been reused, as was the existing carbon dioxide storage and supply system.

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 thermal cycle condensate and feedwater systems consist of six (6) feedwater heaters and two (2) pressure levels of pumping. The condensate system comprises the equipment and piping from the turbine condenser to and including the existing, relocated, deaerator. The feedwater system comprises the equipment and piping from the deaerator outlet to the boiler economizer inlet.

The condensate system was also to be extended and integrated with the ASU Island to provide cooling requirements for this island. The system configuration is generally depicted on the steam cycle heat balance diagrams.

The existing nitrogen storage and supply system was to have been used for the boiler and feedwater heater nitrogen blanketing.

The existing plant design conditions would have remained the same for any new condensate and feedwater systems.

3.7.3.1 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. Existing vacuum pumps are used to create and maintain condenser vacuum. System make-up was to have been 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 through existing piping from the condenser hotwell, an existing gland steam condenser, to the ASU / boiler condensate users, and three existing conventional shell and tube feedwater heaters nos. 1 through 3, and to the existing relocated direct contact deaerating feedwater heater no. 4. Existing drains from heaters no. 2 and 3 are cascaded through heater no. 1 to the condenser.

The existing condensate pumps were originally designed to handle the condensate generated at the maximum turbine 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 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 with the added capability to feed a neutralizing amine to the cycle. The existing Unit 3 sample panel was to have been reconfigured for Unit 4 sampling.

3.7.3.2 Feedwater System

The relocated existing 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 238°C (460°F) at full load. Heater no. 5 receives steam from IP turbine exhaust and heater no. 6 is fed from cold reheat (HP exhaust). Heater no. 5 was to be replaced, because of tube integrity issues. Existing high pressure heater drains cascade through successive existing lower pressure heater drains and are normally directed to the deaerator. Feedwater is also used for de-superheating main steam to auxiliary steam, boiler superheat de-superheating and reheat de-superheating.

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.

3.7.4 Heat Rejection (Cooling Water) Systems

3.7.4.1 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 58 mm (2.3 in) HgA under average annual operating conditions (94 mm [3.7in] HgA under summer design conditions)
- Cooling tower designed at summer conditions with 46.4°C (115.5°F) inlet water temperature, 35.6°C (96 °F) outlet water temperature with an entering 24.4°C (76°F) wet bulb temperature

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

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

System main circulating water piping, including the cooling tower bypass piping, was to be reused.

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

Condenser

An existing two-pass, divided waterbox, steam surface deaerating condenser was to have been reused 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.

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 was to have been replaced with a new tower constructed on the existing basin. The new tower was specified as a crossflow, induced-draft design comprising 5 individual cells, each equipped with 187 kW (250 hp) electric motor-driven fans. Tower design conditions are as stated above.

The tower was to be built over a common existing concrete cold water basin, with an existing pump pit provided at one end. The tower structure was to have been of Fiberglass Reinforced Plastic (FRP) construction. The pump pit is an existing reinforced concrete structure, equipped with existing trash screens.

Main Circulating Water Pumps

The existing 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 an existing 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. With one pump out of service, plant operation could have been continued at reduced load utilizing single pump operation. Limitations on steam turbine load during single pump operation are dependent on ambient conditions.

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 would have maintained condenser vacuum at the design point. During startup, both skids could have been operated in parallel to shorten the time required to pull initial condenser vacuum.

3.7.4.2 ASU/CPU Circulating Water

ASU/CPU Cooling Tower

The ASU/CPU cooling tower was to have been designed to reject cycle heat from the ASU and CPU closed cooling water systems to atmosphere. The tower as specified was to be a two cell, counter flow, induced draft design equipped with 187 kW (250 hp) electric motor-driven fans with variable speed drives. Tower design conditions would have been 37.5ºC (99.5°F) inlet water temperature, 27.5ºC (81.5°F) outlet water temperature with an entering 24.4ºC (76°F) wet bulb temperature and a flow of 18,500 gpm.

The tower was to have been built over a common concrete cold water basin, with a pump pit on one end. The tower structure was specified as FRP, and the pump pit was configured as a reinforced concrete structure consisting of separate chambers for each pump, each equipped with trash screen.

Water chemistry within the ASU/CPU circulating water system was to be maintained through chemical injection and system blowdown.

ASU/CPU Circulating Water Pumps

Two (2) 100% ASU/CPU circulating water pumps were specified as vertical motor-driven constant speed pumps. The pumps were to be self-lubricated and provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge was to have been provided with a motor operated butterfly valve and expansion joint. The discharges from each pump were to be combined into one common supply header feeding two distinct piping loops.

3.7.4.3 DCCPS Circulating Water

DCCPS Cooling Tower

The cooling tower rejects cycle heat from the DCCPS closed cooling water system to the atmosphere. The tower was to have been a single cell, crossflow, induced draft design equipped with a 187 kW (250 hp) electric motor-driven fan with variable speed drive. Tower design conditions were to be 51.6ºC (125°F) inlet water temperature, 33.3ºC (92°F) outlet water temperature with an entering 24.4ºC (76°F) wet bulb temperature and a flow of 15,750 gpm.

The tower was to be built over a common concrete cold water basin, with a pump pit at one end. The tower structure was to be FRP. The pump pit is a reinforced concrete structure consisting of separate chambers for each pump, each equipped with bar screen trash screen.

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

DCCPS Circulating Water Pumps

Two (2) 100% DCCPS circulating water pumps were to have been vertical motor-driven constant speed pumps. The pumps were to be self-lubricated and were to be provided with automatic air release systems to expel contained air from the pump column during pump starting. Each pump discharge was to have been provided with a motor operated butterfly valve and expansion joint. The discharges from each pump were to be combined into one common supply header that feeds the DCCPS spray headers. DCCPS liquor was to be returned by the DCCPS blowdown pumps (see B&W PGG description) to the DCCPS cooling tower.

3.7.4.4 Closed Cooling Water

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

The existing CCW system serves the following major equipment:

- Bearing cooling on the motor-driven boiler feed pumps

- Existing air compressor #4-1, #3 and #1 (relocated) after coolers and intercoolers
- Existing condensate pump motor bearing coolers
- Electro-hydraulic oil coolers
- Sample coolers

The existing 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 existing 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.

A new stand-alone Boiler Island CCW system was to be provided for cooling miscellaneous boiler island equipment.

The Boiler Island CCW system serves the following new equipment:

- Recycle Heater Guide Bearing cooling
- Primary Recycle Fan Bearing cooling
- Pulverizer Lube Oil Cooling

The Boiler Island CCW system consists of the following equipment:

- Two (2) 100% shell and tube heat exchangers
- Two (2) existing 100% horizontal centrifugal pumps (former Unit 3 bearing cooling water pumps), one operating and one standby
- One 100 gallon closed cooling water head tank

The Boiler Island CCW System circulates a water/glycol mixture through the equipment to be cooled and rejects the heat in the system heat exchanger to the existing service water cooling system.

3.7.4.5 Service Water Cooling

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

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

- 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 area CCW heat exchanger

Low pressure service water is pumped to individual equipment coolers via the existing low pressure service water supply header, passes through each cooler and is collected in the service water return header. The heated service water is discharged into the main cooling tower basin as makeup water. Excess water is discharged as tower blowdown to the river.

3.7.5 Service Water

Low pressure service water is also fed to the water treatment area for treatment in a clarifier for use in the service water system. The existing low pressure and high pressure, and new service water systems consist of:

- Unit 4 Low Pressure system:
    - 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 primary and one secondary
- Unit 3 Low Pressure system (to be used as a backup to Unit 4 LP system):
    - One 400 mm (16 inch) strainer, twin basket, 1,022 m^3/hr (4,500 gpm), with manual backwash, to remove particles larger than 4.8 mm (3/16 inch)
    - Two 1,022 m^3/hr (4,500 gpm) horizontal centrifugal pumps, operating in standby
- High Pressure system includes:
    - One new 114 m^3/hr (500 gpm) primary horizontal centrifugal service water pump, and one existing 300 mm (12 inch) strainer, twin basket, to remove particles larger than 4.8 mm (3/16 inch)
    - One existing 415 m^3/hr (1,825 gpm) horizontal centrifugal pump (former #3 ash sluice pump), operating in standby, and one existing 200 mm (8 inch) strainer, twin basket, to remove particles larger than 4.8 mm (3/16 inch)

High Pressure service water is pumped to the existing high pressure service water header for coal area washdown, coal dust suppression, intake screen wash, powerhouse area washdown, fire protection hose stations and is connected to the plant fire water header.

A new service water system provides clarified service water to the Water Treatment System, CPU, boiler, and GQCS Islands, and the existing Powerhouse for miscellaneous service water needs. This system consists of the following:

- One 1,000,000 gallon service water tank
- Three 50% service water pumps

The service water tank is filled from the Water Treatment System.

3.7.6 Fire Protection System

The existing fire protection system was to have been reused. It was to have been extended to encompass new plant equipment. New booster pumps were to have been added for elevated protection system in the new boiler.

3.7.7 Fuel Oil System

The existing fuel oil storage and transfer system was to have been reused. A new fuel oil supply pipe was to be installed from the existing fuel oil storage tank area to new Unit 4 (Boiler 7). The reused existing system includes the following:

- Seven 13,000 gallon fuel oil storage tanks
- Two 100% fuel oil transfer pumps

The existing fuel oil system was also to be extended from the new boiler to the new auxiliary boiler.

3.7.8 Compressed Air System

The compressed air system was to have consisted of two separate systems. A combined instrument and service air system, serving plant air demand, and a second high pressure system for startup boiler fuel oil atomizing air. The existing compressed air system was to have been re-used to meet the general plant instrument and service air demand. New dryers, pre- and after-filter would have been added downstream of the existing air compressors to achieve instrument quality air. Two new redundant high pressure air compressors were to have been added to meet boiler fuel oil atomizing air demand.

The general instrument and service air system was to have included:

- Four (4) existing 33.3% rotary screw, oil-flooded, 7.6 barg (110 psig) discharge pressure, 1,274 Nm^3/hr (750 scfm) compressors. The existing Unit 3 and 4 (#3 and #4-1) compressors were to have been reused in their current location. The Unit 1 (#1) compressor was to have been relocated to the Unit 3 basement. The existing Unit 3 precipitator area compressor (#5) was to have been relocated to the water treatment area.

- Two (2) new 50% heated, 2,040 Nm^3/hr (1200 scfm) air dryer skids, dewpoint of -40°C (-40°F) were to be provided for the three Unit 3 basement area compressors. These dryer skids were to be provided with two 100% coalescing pre-filters designed to remove 99.98% of moisture/oil particles 0.1 micron and larger. These dryer skids were to be provided with two 100% particulate post-filters designed to remove 99.98% of particulate particles 0.1 micron and larger.
- One (1) new 100% heated, 1,274 Nm3/hr (750 scfm) air dyer skid, dewpoint of – 40 ºC (-40ºF) was to be provided for the one water treatment area compressor. This dryer skid was to be provided with two 100% coalescing pre-filters designed to remove 99.98% of moisture/oil particles 0.1 micron and larger. This dryer skid was to be provided with two 100% particulate post-filters designed to remove 99.98% of particulate particles 0.1 micron and larger.
- One (1) new 11.25 m^3 (3,000 gallon) instrument air receiver in the Unit 3 basement area
- One (1) new 3.78 m^3 (1,000 gallon) instrument air receiver in the water treatment area

The boiler fuel oil atomizing system was to have included two new 100% rotary screw, oil-flooded 12.1 barg (175 psig) discharge pressure, 1,316 Nm3/hr (775 scfm) compressors and one new 3.78 m^3 (1,000 gallon) service air receiver.

The higher pressure boiler fuel oil atomizing system was to have been piped separately from the general compressed air system. The new instrument and service air system would have included pressure control valves to prevent service air users from lowering the instrument air pressure below 80 psig. The new general plant compressed air system was to have been cross-tied to the existing compressed air system. New piping was to have been installed from the coalescing pre-filter to the new compressed air tanks and from the new compressed air tanks to the new plant compressed air header. A check valve was to have been installed in the feed piping for the existing plant air header to prevent oil residue that might have existed in the existing plant air piping, from entering the new piping system.

Instrument air and service air was to have been distributed to the collective interface points at the boiler, GQCS, ASU, and CPU Islands. New air piping in the boiler and GQCS areas were to have been ASTM A312 TP 304 stainless steel.

3.7.9 Potable Water and Sanitary Drain Systems

3.7.9.1 Potable Water

The existing city water system was to have been used as the potable water system supply source. A booster pump skid was to have been added to raise supply pressure to meet new potable water system pressure requirements including safety eye washes and showers. Restroom facilities were to have been provided in the water treatment building. Unconditioned potable water was also to be provided to the ASU and CPU Islands for restroom facilities and safety eye washes and showers. The new potable water system was to have been connected to the existing powerhouse potable water system.

Boiler and GQCS Islands and BOP areas requiring safety eye washes and showers were to have been provided with conditioned (heated) potable water.

3.7.9.2 Sanitary Drains

The existing City Sewer system was to have been used to discharge sanitary drains. Existing plant sanitary drains were to be reused. New lift stations would have been added to convey new plant sanitary drains to the existing city sewer.

3.7.10 Stack

A new 136 m (446 ft) tall concrete chimney was to have been provided. The stack would have included a 9 ft. diameter stainless steel main flue gas liner and a 3 ft. diameter stainless steel CPU Island vent stack. The 9ft. diameter main stack was to discharge monitored volumes of flue gas during unit startup, until the flue gas was diverted to the CPU Island, and discharge flue gas during normal shutdown. The vent stack was to discharge unmonitored volumes of gases during CPU island startup, normal operation, controlled shutdown, and unmonitored volumes of carbon dioxide during uncontrolled abnormal shutdowns.

The stack was to consist of:

- Outer reinforced concrete shell (27.6 MPa [4,000 psi] design) per ACI-307
- Stainless steel liner
- Stainless steel CPU Island vent pipe
- Stainless steel breeching duct
- One (1) full height elevator and access ladder with rest platforms
- CEMS and opacity ports of stainless steel construction for the main 9 ft. stack
- One (1) full concrete roof with Type 316L stainless steel hatch
- Aviation lighting, two levels of four medium intensity strobe lights
- Chimney electrical system
- Lightning protection

3.7.11 Coal Handling System

3.7.11.1 Existing Coal Handling System

The existing Coal Handling System (CHS) served Units 1-3 and handled both PRB and Illinois bituminous coal before being shut down in late 2011.

Before the Meredosia plant was shut down, PRB coal used to be delivered to the plant by river barges, while bituminous coal was delivered by truck. No provisions for accurate blending of bituminous and PRB coals were provided in the legacy system.

Coal was unloaded from the barges using a clamshell 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 tonnes/hr (500 tons/hr). Conveyor E transported the coal to the breaker building where it discharged to Belt Feeder F. This feeder discharged coal to a two-position flop gate diverter that could send the fuel to either the granulator or to the tail end of Conveyor D, which discharges to the Yard Hopper.

The granulator inlet is furnished with a grizzly classifier that directs oversize coal to the granulator while the finer particles bypass the granulator and were to be mixed with the sized product, and then discharged onto the 454 tonnes/hr (500 tons/hr) Conveyor B. Conveyor B elevates the coal to the tripper gallery where it is discharged 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 coal from the coal yard was 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 was discharged onto Belt Feeder F for further processing as described above.

3.7.11.2 Repowered Plant Coal Handling System Configuration

The existing CHS was to have been modified and extended to deliver coal to Unit 4 (new boiler 7).

The barge unloading system was to have been used for maintaining the PRB coal pile inventory and for on-line blending of PRB coal with bituminous coal for Unit 4, or for directly receiving blended coal.

In the event that pre-blended coal would not have been available for some period of time, bituminous coal for Unit 4 was to have been delivered to the plant by trucks and a pile of bituminous coal was to have been formed by yard machines including bulldozers, loaders, and scrapers. Yard machines were to be used to transfer the coal from this pile to the existing reclaim hopper.

Conveyor C was to have been extended to a new discharge chute leading to a new drag chain conveyor located at new boiler 7. The drag chain conveyor was to have been used to fill the three (3) new boiler 7 coal silos. A dust collection system was to service the new transfer point, drag chain conveyor, and new coal silos.

The outdoor portion of the new Conveyor C extension would have incorporated ¾-style hood covers over the conveyor belt. A walkway was to have been provided along the extended Conveyor C for service and maintenance purposes.

The Oxy-Combustion Boiler was designed to burn a 60/40 blend of PRB and Illinois Bituminous coal. The blending of bituminous coal and PRB coal for Unit 4 could have been provided by three (3) scenarios as follows:

Off Site Blending Scenario A (most accurate)

Coal was to have been purchased pre-blended by the coal supplier and barged to site.

Blending Scenario B (more accurate)

One new conveyor belt scale was to have been furnished on the barge unloading conveyor E to monitor the flow rate of PRB coal. Existing Conveyor B belt scale provides the combined flow rate signal. The existing variable speed yard reclaim and barge unloader belt feeders were to provide control parameters necessary to produce an accurate blend. Bituminous coal was to have been transferred from the reclaim hopper belt feeder onto existing Conveyor A, which discharges to the existing belt Feeder F. The PRB coal was to have been transferred from the barge to Feeder F by the existing Conveyor E. Blended Feeder F fuels were to have been discharged to the existing coal granulator and handling was to continue as described above.

Scenario C (less accurate)

When coal was not being actively unloaded from barges, yard machines were to be used to transfer both bituminous coal and PRB coal from their respective piles into the existing yard reclaim hopper. The blending coal ratios were to have been controlled by volume of PRB coal blended together with bituminous coal as it was pushed into the reclaim hopper. Blended coal was to have been transported by the existing Conveyor A to the breaker building and processing was to continue as described above.

3.7.12 Water and Wastewater Treatment

3.7.12.1 Makeup Water

Sources of Makeup Water

The Illinois River was to be the primary source of makeup water, supplying water for the following uses:

- Screen and strainer backwash
- Cooling tower makeup
- Boiler makeup
- GQCS makeup (CDS and DCCPS)
- CPU Process/Service water makeup
- Equipment cooling
- Equipment wash-down
- Coal handling dust suppression
- Bottom ash and by-product handling

City water was to be used directly (without treatment) for:

- Fire protection makeup
- Eye wash and safety showers
- Potable water for drinking and restrooms

Treatment of Makeup Water

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

- All of the river water passed through existing intake screens. The screens were backwashed using high pressure service water (river water). The backwash water was then discharged directly back to the river.
- Downstream of the screens, river water was pumped through various existing strainers for use in high pressure service water (coal handling dust suppression) and low pressure service water (equipment cooling, main cooling tower supplemental makeup and air compressor cooling) systems. The strainers were backwashed using their own inlet water.
- Low pressure service water was to be clarified to remove suspended solids to less than 5 ppm using a new solids contact clarifier for various purposes indicated below:
    - ASU/CPU cooling tower makeup
    - CPU CO_2 Condenser makeup
    - New coal handling wash down and existing dust suppression
    - Bottom ash removal makeup
    - GQCS humidification
    - DCCPS ME wash, DCCPS reagent prep, and DCCPS cooling tower supplemental makeup
    - Makeup to Ultrafiltration, and Reverse Osmosis
- The clarification process main equipment components, chemical reagents, and by-products 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)

  - By-products: Filter cake (approximately 50% solids, chemically "fixed", expected to pass Toxicity Characteristics Leaching Procedure test)

- Clarified service water was to be further purified for the following uses using the new process described below:
  - Ultrafiltration and Reverse Osmosis.
    - Uses: DCCPS ME wash and Mixed Bed Demineralization makeup
    - Equipment: Cartridge filters, ultrafiltration unit, tanks, reverse osmosis feed pumps, and booster pumps, reverse osmosis unit
    - Chemical reagents: Possible reagents were sodium hypochlorite, acid, caustic, anti-scalant, sodium bisulfite, detergent
    - By-products (used as GQCS humidification water makeup) : Ultrafiltration backwash, reverse osmosis reject (concentrated clarified river water)
    - By-products (offsite processing): Rinses from chemical cleaning of reverse osmosis units
  - Mixed Bed Demineralization
    - Uses: Boiler makeup, bearing water makeup, and closed cooling water makeup
    - Equipment: Off-site regenerated mixed bed vessels

3.7.12.2 Wastewater Treatment

Liquid effluent limitations for discharge to the Illinois River are identified in Table 3-8 below.

The Unit 4 liquid effluents were not to be discharged to the existing on-site ash ponds.

Some Unit 4 streams, such as the main cooling tower and the ASU/CPU cooling tower blowdown, were to have been 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., anti-scalant, biocide, sulfuric acid, etc.) present. The ASU/CPU cooling tower makeup water portion of this stream would have also been clarified to remove suspended solids.

CPU wastewater would have required neutralization prior to being recycled for by-product conditioning or discharged to the DCCPS wastewater treatment system.

The Unit 4 GQCS/DCCPS system liquid waste was to have been recycled for by-product conditioning to the maximum possible extent, with the remainder of this water being treated as necessary in the DCCPS wastewater treatment system prior to release to the discharge flume.

Coal yard runoff was to have been collected in a new Coal Pile Runoff (CPR) pond and treated in a new CPR treatment system consisting of a clarifier designed to remove suspended solids and adjust pH prior to release to the discharge flume. Boiler area, bottom ash and by-product area and other area process drains which could have contained process suspended solids would also have been directed to the CPR treatment system.

The Unit 4 miscellaneous plant drains were to have been treated to remove oil and suspended solids in an oil water separator prior to release to the discharge flume. Existing Unit 1, 2 and 3 miscellaneous plant drains was to have been directed to the new coal pile runoff pond and treated in the new coal pile runoff treatment system.

Boiler and auxiliary boiler blowdown, which consist of high purity water with small quantities of minerals, was to have been discharged to the main cooling tower.

Table 3-8: River Discharge Limits

Analysis Parameter (mg/l unless noted otherwise)	**Criteria**
Chloride	<500 ppm
Sulfate	< 1500 ppm
Fluoride	< 1.4 ppm
Phosphate	no added
Ammonia, as N	pH and temperature dependent
pH	6.0 – 9.0 standard units
Oil & Grease	< 15 ppm
Total Suspended Solids	< 15 ppm average < 30 ppm max instantaneous
Aluminum	< 0.087 ppm
Antimony	< 0.006 ppm
Arsenic	< 0.19 ppm
Barium	< 5 ppm
Beryllium	< 0.004 ppm
Boron	< 1.0 ppm
Cadmium	< 0.002 ppm
Chromium, total	< 0.014 ppm
Cobalt	< 1.0 ppm
Copper	< 0.021 ppm
Iron	< 1.0 ppm
Lead	< 0.033 ppm
Manganese	< 0.15 ppm
Mercury	< 0.000012 ppm
Nickel	< 0.009 ppm
Selenium	<1.0 ppm

Analysis Parameter (mg/l unless noted otherwise)	**Criteria**
Silver	< 0.005 ppm
Thallium	< 0.001 ppm
Zinc	< 0.039 ppm
Nitrate-Nitrogen, as N	< 10.0 ppm
Cyanide	n/l
Phenols	n/l
Hardness Dependent Metals Assumed	< 30 ppm

(1)Cooling tower discharges comprising only River Water makeup that has been cycled up as a result of the evaporative cooling process are excluded from this requirement. Exceedance of the stated limit might also be possible provided the impacts to the river, as be demonstrated by a mixing zone analysis, are insignificant.

n/l – No Limit

The collection method, main equipment components, chemical reagents, and by-products for the proposed wastewater treatment system (WWTS) process are briefly presented below.

The Unit 4 DCCPS wastewater treatment system included biological treatment for nitrate removal and physical-chemical treatment for heavy metals removal.

- Treatment process: Three-stage anaerobic digesters followed aeration for removal of residual COD and BOD. Effluent from the biological treatment was to have been treated for metals removal by metal hydroxide and metal sulfide precipitation. The effluent from the biological/chemical treatment process was to have been clarified and filtered before being discharged.
- Equipment: Anaerobic digesters, post-aeration tank, hydroxide precipitation and sulfide precipitation reaction tank(s), coagulation tank, solids contact clarifiers, metal removal polishing filter, sludge thickener, sludge recirculation and forwarding pumps, filter presses for sludge dewatering, pumps for sludge recirculation and filter press feed.
- Chemical reagents: Ferric chloride (coagulant), sulfuric acid (pH adjustment), carbon source such as MicroC (biological electron donor), urea and phosphoric acid (biological nutrients), caustic (hydroxide metal precipitation, organosulfide (sulfide metal precipitation), polymer (flocculant/coagulant aid).
- By-products: Filter cake (approximately 50% solids, chemically “fixed”, expected to pass Toxicity Characteristics Leaching Procedure test) and waste oil, both of which were to be trucked off-site for final disposal.

3.7.12.3 Condensate Polishers

The repowering project would not have used the existing condensate polishing system. The existing condensate polishing system was to have been isolated by using the existing valves and bypass system. A new phosphate feed system was to provide chemical feed to the boiler drum in order to condition boiler water.

3.7.13 Legacy Equipment

The FutureGen 2.0 Project was to have included reuse of a significant portion of the existing Meredosia Unit 4 steam cycle and associated equipment, as described in the previous sections. Phase I identified existing equipment that required further assessments to be completed in Phase II. During Phase II, further inspection and assessment was performed on the major equipment identified as long lead replacement items, including steam turbine, condenser, and low pressure feedwater heaters in order to validate their suitability for reuse and to better quantify required refurbishment activities.

3.7.13.1 Phase II Steam Turbine Assessment

A detailed assessment of the existing steam turbine was performed during Phase II, including the following specific activities:

- Complete inspection of all turbine, generator and exciter bearings
- Complete inspection of all turbine and generator lube oil pumps and lube oil coolers
- In-place electrical testing of the generator stator and field
- Throttle valve inspection
- Generator crawl thru
- Borescope of HP-IP turbine where possible
- Turbine HP-IP rotor bore inspection and rotor condition assessment
- Turbine HP-IP rotor remaining life analysis

Overall, these evaluations concluded that the existing turbine was in suitable condition for continued operation in the proposed oxy-combustion cycle and was assigned a probable remaining life of 20 years. A follow-up inspection interval of 20 years or 500 additional starts (whichever comes first) was also recommended, although planned re-inspection would have likely been scheduled at approximately 10-year intervals.

3.7.13.2 Phase II Condenser Assessment

A partial eddy current testing program was completed on the condenser tubes during Phase II. Test results indicated wall thickness reduction on the tubes tested. Based on these findings, the condenser would have needed to be completely re-tubed, although no work would have been required in the stainless steel air removal section.

The circulating water return top and bottom plates were eroded beyond a simple epoxy coating repair and would have had to have been replaced. Welded joints for thirteen shell piping connections were determined to be compromised. These connections show evidence of escaping steam. All thirteen connections would have required repair to support continued condenser operation. Other penetration welds would also have required further NDE testing and repairs.

3.7.13.3 Phase II Feedwater Heater Assessment

Evaluations of the Unit 4 low pressure feedwater heaters were conducted during Phase II, with the following results:

- Heater #1 was subjected to a 25% eddy current testing regimen. A total of 439 tubes were tested, 419 tubes were found with no wall degradation detected. Only 1 tube of the 439 was found with more than 50% wall reduction and was planned to be plugged in Phase III. Based on these findings, this heater would not have required re-tubing and would have been cleaned and in-service tested in Phase III.
- Heater #2 was subjected to a 25% eddy current testing regimen. A total of 249 tubes were tested, 248 tubes were found with no wall degradation detected. Only 1 tube of the 249 was obstructed. Based on these findings, this heater would not have required re-tubing. The heater would have been cleaned and in-service tested during Phase III.
- Unit 4 low pressure feedwater heater #3 was subjected to a 25% eddy current testing regimen. A total of 223 tubes were tested. All tubes were found with no wall degradation detected. Based on these findings, this heater would not have required re-tubing. The heater would have been cleaned and in-service tested during Phase III.

3.7.13.4 Planned Phase III Refurbishment Work

The Alliance established several work packages, as identified below, that were intended to implement the recommended equipment refurbishment activities identified in both the Phase I and Phase II assessments to rehabilitate the Legacy Equipment. The activities associated with these packages were intended to be completed in Phase III and had been budgeted for accordingly.

M04 -Circulating Water Pumps Overhaul

Equipment Name	**Rehab Scope**
CIRCULATING WATER PUMPS	take off site and rebuild pumps, and replace motor bearings, test motor

M05 -BFW Pump Overhaul

Equipment Name	**Rehab Scope**
BOILER FEED PUMP LUBE OIL SYSTEMS	inspect the coupling
BOILER FEED PUMPS	take off site and rebuild pumps, and replace motor bearings, test motor

M08 -Steam Turbine Refurbishment

Equipment Name	Rehab Scope
GENERATOR SEAL OIL SKID AIR/HYDROGEN	open, clean and inspect
EXCITER	open, clean and inspect
STEAM TURBINE GENERATOR	open, clean and inspect, repair hydrogen side seal oil leak
OIL RESERVOIR	open, clean and inspect
STEAM TURBINE	Open and clean, replace seals, replace dummy seal
TURBINE HYDRAULIC OIL COOLERS	open, clean and inspect
TURBINE LUBE OIL COOLERS	open, clean and inspect
LUBE OIL PURIFIER	open, clean and inspect
TURBINE OIL TRANSFER PUMP	open, clean and inspect
STEAM TURBINE LUBE OIL SKID	open, clean and inspect
AUXILIARY OIL PUMP (TURNING GEAR OIL PUMP)	open, clean and inspect
EMERGENCY LUBE OIL PUMP	open, clean and inspect
GENERATOR GAS COOLERS	open, clean and inspect
MAIN LUBE OIL PUMP	open, clean and inspect
OIL VAPOR EXTRACTOR	open, clean and inspect
SEAL OIL BACKUP PUMP AIR SIDE	open, clean and inspect
TURBINE HYDRAULIC OIL PUMPS	open, clean and inspect
TURBINE HYDRAULIC OIL SKID	open, clean and inspect
TURNING GEAR	open, clean and inspect

M09a -Coal Handling System - Mechanical Repairs

Equipment Name	Rehab Scope
BELT TRANSFER FEEDER (B TO G)	open, clean, inspect install new skirting
BARGE UNLOADER	open, clean, inspect install new skirting
BARGE UNLOADER HOPPER	open, clean, inspect install new skirting
CRUSHER	Overhaul
CONVEYOR A	open, clean, inspect install new skirting
CONVEYOR B	open, clean, inspect install new skirting
CONVEYOR D	open, clean, inspect install new skirting
CONVEYOR E	open, clean, inspect install new skirting
CONVEYOR F	open, clean, inspect install new skirting
CRUSHER FEEDERS	open, clean, inspect install new skirting
DUST SUPPRESSION SPRAY SYSTEM	open, clean, inspect install new skirting
RECLAIM HOPPER	open, clean, inspect install new skirting
TRAMP IRON CHUTE	open, clean and inspect

TRAMP IRON MAGNETIC SEPARATOR	open, clean, inspect install new skirting
TRANSFER TOWER	open, clean, inspect install new skirting
TRIPPER CONVEYOR C	open, clean, inspect install new skirting
YARD STORAGE HOPPER	open, clean and inspect

M13 -Condenser Tube Refurbishment

Equipment Name	**Rehab Scope**
CONDENSER	Re-tube and repair
GLAND STEAM CONDENSER	open, clean and inspect
GLAND STEAM CONDENSER EXHAUSTERS	open, clean and inspect

M14 -General Mechanical

Equipment Name	**Rehab Scope**
SAC INTER & WATER JACKET COOLER	open, clean and inspect
AIR RECEIVER- 4-IA- RCV-0001	Inspect, test/replace relief valves, pressure test
AIR RECEIVER- 4-IA- RCV-0002	Inspect, test/replace relief valves, pressure test
AIR RECEIVER 4-IA-RCV-0005	Inspect, test/replace relief valves, pressure test
AIR RECEIVER 4-IA-RCV-3001	Inspect, test/replace relief valves, pressure test
CLOSED COOLING WATER STORAGE TANK	drain, open clean and inspect
CLOSED COOLING WATER HEAT EXCHANGERS	shell and tube, open clean and inspect , tube and shell sides
CLOSED COOLING WATER PUMP	replace bearings, clean
CO_2 TANK	open, clean and inspect
CO_2 VAPORIZER	open, clean and inspect
STATION AIR COMPRESSOR 4-2	open, clean and inspect
CONTROL AIR AFTERCOOLER	Gardner Denver
CONTROL AIR COMPRESSORS	Gardner Denver - oil leaks on comp and filter
CONTROL AIR COMPRESSOR WATER JACKET COOLER	Gardner Denver
DEAERATOR (HEATER NO. 4)	clean, inspect, get recertified
DEEP WELL PUMP	open, clean and inspect
DIESEL ENGINE DRIVEN FIRE PUMP	open, clean and inspect
ELECTRIC MOTOR DRIVEN FIRE PUMP	open, clean and inspect
ELECTRIC MOTOR DRIVEN JOCKEY PUMP	open, clean and inspect

FILTERED/SERVICE WATER STORAGE TANK	open, clean and inspect
FIRE TANK	open, clean and inspect
IGNITION & LIGHT FUEL OIL TANK	open, clean and inspect
HIGH PRESSURE FEEDWATER HEATER NO. 6	open and clean
IGNITION & LIGHT FUEL OIL PUMPS	open, clean and inspect
INSTRUMENT AIR COMPRESSORS	Gardner-Denver , overhaul compressor, o-ring replacement
LOW PRESSURE FEEDWATER HEATER NO. 1	open and clean
LOW PRESSURE FEEDWATER HEATER NO. 2	open and clean
LOW PRESSURE FEEDWATER HEATER NO. 3	open and clean
LOW PRESSURE SERVICE WATER PUMP	open, clean and inspect
VACUUM PUMPS	replace seals
MAIN LIGHT FUEL OIL SUPPLY PUMPS	open, clean and inspect
NITROGEN TANK	open, clean and inspect
OUTDOOR PUMPHOUSE SUMP PUMPS	open, clean and inspect
SAC AFTERCOOLER	open, clean and inspect
SAMPLE PANEL	open, clean and inspect
DEAERATOR STORAGE TANK	clean, inspect, get recertified
TRACK HOPPER SUMP PUMP	open, clean and inspect
UNIT 1 EXIST PRECIPITATOR DRAIN PUMPS 1A & 1B	open, clean and inspect
UNIT 1&2 EXIST. BOILER ROOM SUMP PUMPS 3-A,3-B	open, clean and inspect
UNIT 1&2 EXIST. TURBINE ROOM SUMP PUMPS 3-A,3-B	open, clean and inspect
UNIT 3 EXIST. TURBINE ROOM SUMP PUMPS 3-A,3-B	open, clean and inspect
VACUUM SYSTEM SEAL WATER COOLERS	open, clean and inspect
NO. 6 SU PUMP	open, clean and inspect

M15 -Condensate Pump Overhaul

Equipment Name	**Rehab Scope**

CONDENSATE PUMPS	take off site and rebuild pumps, and replace motor bearings, test motor

3.8 Electrical and Control Systems

3.8.1 Overall Plant Electrical Design

To support the new oxy-combustion facility, several changes to the existing site electrical transmission and distribution systems were required to both free up plot space for the new project equipment and interconnect the new facilities with the existing electrical grid. Such changes included the following:

- The existing Unit 4 Main Transformer (GSU) 138kV overhead distribution output line was to be re-routed from the Unit 4 generator step-up transformer to the existing 138kV switchyard. The existing overhead line was demolished in Phase II, with the rerouted overhead installation planned for Phase III.
- The existing Unit 4 Main Auxiliary Transformer 69kV overhead distribution supply line was to be re-routed underground from the transformer to the existing generator circuit breaker #751in the 69kV switchyard, to continue to feed existing Unit 4 loads reused in the oxy-combustion plant. The existing overhead line was demolished in Phase II, with the rerouted underground installation planned for Phase III.
- The existing Unit 3 Main Transformer (GSU) 138kV overhead distribution output line was to be re-routed to the existing 138kV switchyard and re-purposed to supply power to a new oxy-combustion Auxiliary Transformer required to feed the new project loads. The existing overhead line was demolished in Phase II, with the rerouted overhead line and new transformer installation planned for Phase III.
- A number of other miscellaneous existing overhead transmission and distribution lines associated with Meredosia Units 1, 2, and 3 were re-routed as part of the Phase II work to clear plot space for new combustion facilities.

The new Oxy-Combustion Auxiliary Transformer was to be a three-winding, 144/72/72 MVA, 138/13.8/13.8kV, mineral oil-filled transformer. Non-segregated bus duct was to connect the secondary and tertiary of the transformer to two (2) new 13.8kV, 3000A, 63KAIC arc resistant pieces of switchgear for distribution to the ASU and CPU Islands via above ground cable routed in cable tray.

A Boiler/GQCS Power Control Module (PCM) was to be located near the new oxy-combustion Auxiliary Transformer. The Boiler/GQCS PCM was to house the 13.8kV switchgear in addition to 4.16kV arc resistant switchgear and Motor Control Centers (MCC), 480V switchgear, 480V MCC's, 120V AC UPS & 125V DC Battery Systems, and DCS cabinets. The Boiler and GQCS area BOP loads was to be supplied from the electrical equipment within the Boiler/GQCS PCM through above ground cable.

A Water Treatment (WT) PCM was to be located near the water and waste water treatment facility. It was to contain a 4.16kV MCC, 480V MCC and DCS cabinets. The 4.16kV MCC was to be fed from the 4.16kV MCC in the Boiler/GQCS PCM through both above ground and below ground duct bank routed cable south of the ASU Island. The water and waste water treatment loads, ASU/CPU cooling tower and DCCPS cooling tower was to be supplied from the electrical equipment in the WT PCM through both above ground and below ground duct bank cable.

A Main Cooling Tower (MCT) PCM was to replace the existing switchgear currently supplying the existing MCT area. The MCT PCM was to contain a 480V MCC and DCS Cabinets. The 480V MCC was to re-use the existing MCT switchgear feed from the existing Unit 4 Switchgear.

An existing 1,600kW, 480V, diesel generator was to be re-located near the new Oxy-Combustion Auxiliary Transformer and Boiler/GQCS PCM. The diesel generator was to feed 480V switchgear within the PCM that was to provide emergency power to essential service loads for all islands.

Existing BOP equipment was to continue to receive power from their existing sources. New BOP loads that were to be located within the existing buildings were to be fed from the existing electrical distribution equipment.

3.8.2 Instrumentation and Control (I&C) Systems

The design of the control system and related equipment would have adhered to the principle of “safe operation” at all system levels, such that any component does not cause a hazardous condition while, at the same time, preventing an excessive number of equipment or system trips.

All instrumentation and control elements would have been suitable for the electrical classification of the area in which they were to be installed and would have been designed, fabricated, inspected and tested in accordance with applicable codes and standards.

The re-powered facility was to be controlled from a central processor cabinet (main plant control room) employing the Plant Control System (PCS) design. The PCS was to be comprised of the Boiler Control System (BCS), Burner Management System (BMS), Gas Quality Control System (GQCS), Turbine Control and Balance of Plant (BOP). During normal operation the control system was to be in the automatic mode. Commands could also be initiated manually from the PCS console when in manual mode. The PCS was to also provide supervisory control of the other control systems (ASU, CPU, and PLC based controllers).

3.8.2.1 I & C Philosophy

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

- Common/consistent units of measure application
- Standardized HMI display formats, text, color and display methods with active participation by plant staff in their development

- 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

3.8.2.2 Boiler and Combustion I&C

A Distributed Control System (DCS) was 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 was to be 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 BOP (i.e. Coal Handling PLC and Water Treatment PLC) and Boiler (i.e. Sootblower PLC, Air Heater PLC, and Auxiliary Boiler PLC)..

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 were to be 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, were to be 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 was provided for control processors, data highways, interface controllers and power supplies. The conceptual system architecture is shown in and Figures 3-46 and 3-47.

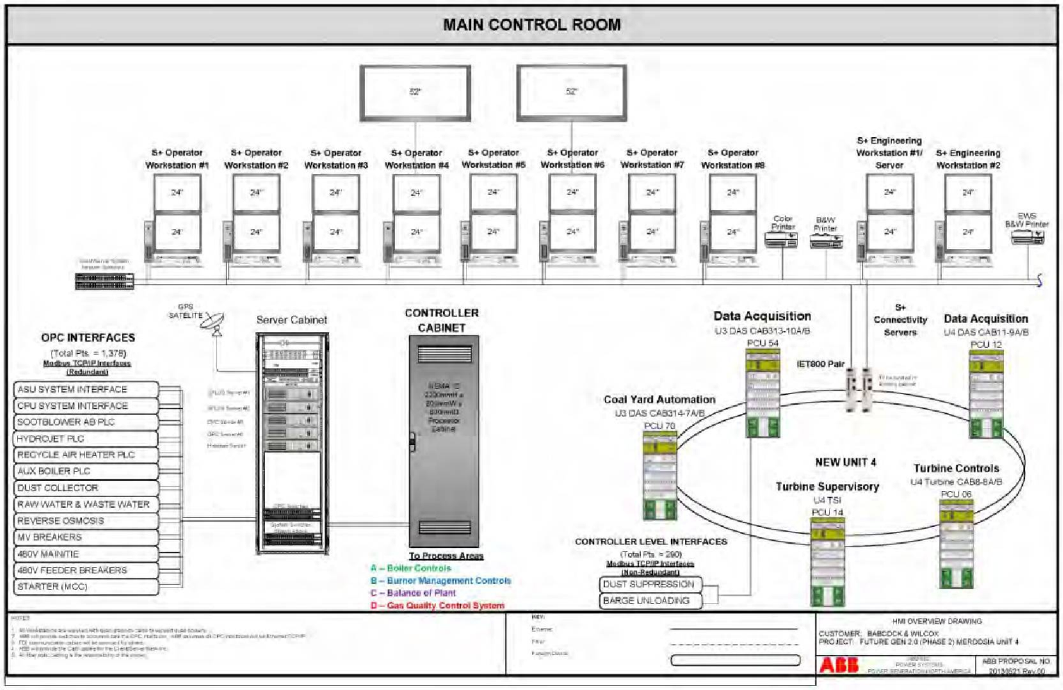


Figure 3-46: Plant Control System Architecture (Main Control Room)

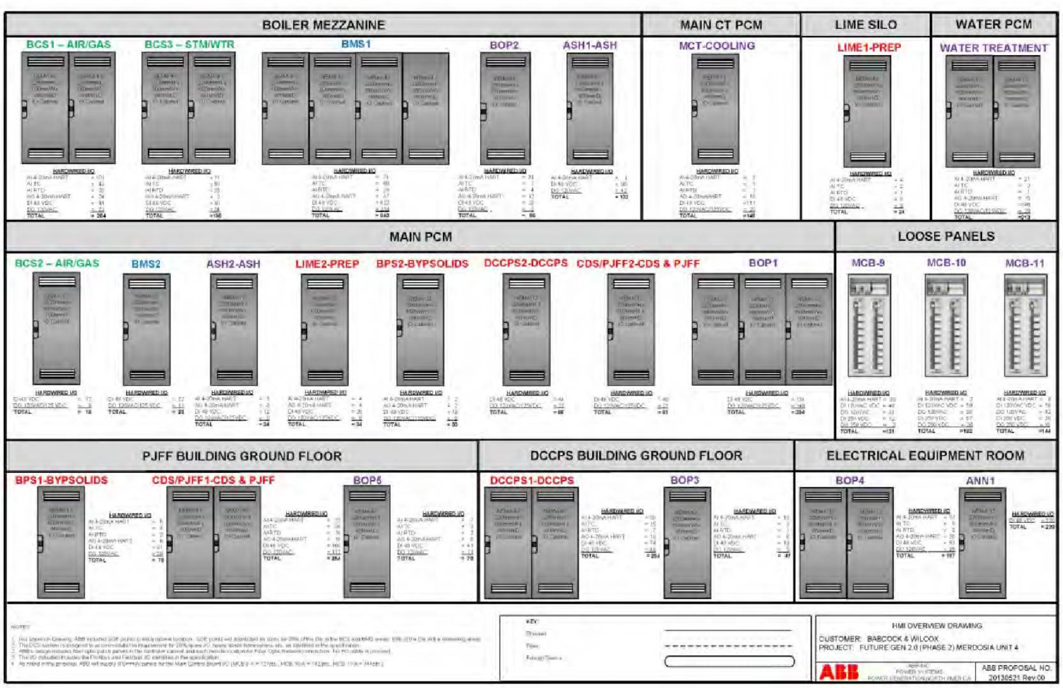


Figure 3-47: Plant Control System Architecture (Remote I/O Cabinets)

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

The plant instrumentation and the PCS were to be 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 was 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, was 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.

3.8.2.3 ASU and CPU I&C

The ASU and CPU facilities were to be designed for efficient full time on-shift staffing. The operator was to be able to start, control and stop all major pieces of ASU equipment in the facility from the ASU control room. The CPU facility was to be controlled from the Power Plant Control Room. The facilities were to be 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 were to be monitored and logged. This was to 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 would have been designed for safety and to protect the equipment. If a shutdown interlock was activated, the facility was to automatically shut down in a safe mode. Once the cause of the shutdown has been identified and corrected, the interlock was to be cleared and the facility could be restarted.

3.8.2.4 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 was to be placed on migrating the existing unit control, alarm, and monitoring points to the new Distributed Control System (DCS), to the extent practical, and integrating new BOP controls into the new DCS.

Activities included in the BOP I&C modifications were:

- Hand switches, selector switches and indicating lights associated with Section 7 of the MCB yard/bus breaker control, and Section 8 of the MCB generator controls were to be retained. The pistol grip lockout relays on these board sections was to be retained. Bus voltage and ammeters were to be retained on Section 7, indication and meters on Section 8 of the MCB were to be retained.
- Visual Annunciation Windows of Section 7 & 8 of the MCB were to be abandoned, and integrated into the DCS unless the information was available from a direct input. Any existing Unit 4 Visual Annunciation Windows for Unit 3 were to be integrated into the new DCS as determined necessary for Unit 4 operations. Those annunciated items requiring assignment to sequence of events were to be assigned points on DCS I/O cards that could time stamp the transition of the point to 1ms.
- Operator Interfaces associated with Section 9 through 11 of the MCB were to be integrated into the DCS. Section 9 through 11 of the MCB were to be covered with new fiberboard skins.
- Required plant computer points were to be retained and integrated into the DCS through the existing Bailey Control network by the DCS supplier.
- A limited number of existing analog control loops were to be integrated into the DCS through the replacement of new smart valve positioners and process transmitters.
- FW Heaters were to be updated with 2 new GWR Level Transmitters 4-20 ma transmitters each. New Smart Valve positioners were to be provided for all existing or new primary and alternate turbine water induction prevention drain valves. Control was to be implemented in the DCS.
- Required existing instruments and transmitters were assumed to be functional and were to be retained, reused, and wired to the DCS as required to repower the facility
- ST Controls were to be integrated into the DCS through the existing Bailey Control network by the DCS Supplier. Turbine Controls were to be retained as is, with little

modifications if any. New Operator Interface was to be provided through the DCS Operator work stations by the DCS manufacturer's Turbine Controls Group.

- Coal Handling was to be integrated into the DCS through the existing Unit 3 Bailey Control network by the DCS Supplier. Portions of the logic were to be upgraded to accommodate the required deletion of equipment for Units 1 through 3, and the addition of new Unit 4 conveyor controls.
- Water Treatment PLC systems were to be interfaced to the DCS through a TCP/IP interface for display and limited control in the DCS. Related alarms and controls were to interface directly to the DCS remote I/O.
- Operator interface was to be provided in the means of new DCS Operators Workstations on a new Control Console array facing the existing Unit 4 Control Sections. These components were to be provided by the DCS Supplier.
- Remote I/O cabinets/plates were to be used to the maximum extent to reduce wiring and improve the integration of existing motor control.

4.0 Cost Estimate and Schedule

4.1 Capital Cost Estimate

The total estimated "all-in" capital cost for the Oxy-Combustion Project in as-spent dollars is $1.266 billion as summarized in Table 4-1. The project cost estimate was developed from the ground up, with each island supplier providing the costs for their respective island scope, and with the Alliance and URS providing the owner's cost estimate. This estimate includes the purchase of Meredosia assets and associated permits, all EPC costs associated with the repowering, owner's costs, startup, commissioning costs, financial closing costs, initial working capital, debt service and owner's management reserves.

Table 4-1: Oxy-Combustion Project Capital Cost Summary

Cost Category	As Spent $000's
FEED and Site Preparation Costs	$ 90,270
B&W, BWM, and Air Liquide EPC Costs	-
Air Liquide ASU	N/A – OTF Operating Cost – See Section 5.1.1 and 5.2.1
B&W Boiler & GQCS	$ 134,490
Air Liquide CPU	$ 168,911
BWM JV Balance of Plant	$ 508,977
Startup & Commissioning Costs (not included in Contractor Scope)	
FGA Start-Up of Legacy Equipment & O&M Labor (including CPU)	$ 10,003
Coal / Fuel Oil / Raw Materials & Waste Disposal / Other Consumables	$ 24,087
Purchased Power	$ 8,031
Credit for Power Sold	$ (14,903)
Meredosia Site Purchase and Readiness Costs	$ 29,346
Owner's Costs	
URS / FGA Scope - Phase 2 & 3	$ 72,345
Alliance G&A - Phase 2 & 3	$ 21,928
Project Development - Phase 2	$ 18,336
Project Management - Phase 3	$ 4,058
Capital Spares	$ 8,974
O&M Training & Mobilization	$ 4,970
Builder's Risk & General Liability Insurance	$ 8,190
Local Property Taxes	$ 2,654
Initial Coal Pile / Fuel Oil Tank Fill/Raw Material Stock Pile	$ 2,547

Cost Category	As Spent $000's
Interconnection Facilities (MISO, Ameren, & Prairie Power)	$ 1,495
State Sales Tax	$ -
Operating Period Initial Working Capital - LOC Commitment Fees	$ 469
Financial Closing Costs	
Legal & Consulting Fees	$ 6,209
Upfront Financing Fees	$ 12,600
Origination Fees	$ 9,598
Commitment Fees During Construction	$ 5,089
Interest During Construction	$ 31,010
Bond Placement Fees (Term Financing)	$ 8,820
Initial Debt Service Reserve - LOC Commitment Fees	$ 388
Owners Management Reserve	$ 86,991
Total Project Costs	**$ 1,265,883**

Phase I (Project Definition) was completed in January of 2013. During Phase II (Permitting and Design), the Alliance and its partners completed a detailed FEED study in March 2014 and completed approximately 80% of the detailed design engineering. Detailed specifications for approximately 90% of the major equipment were completed and vendor subcontracts to provide pricing certainty were secured for both the equipment and selected construction labor and materials. This level of design and cost certainty is far greater than for most coal-fueled power plant projects, which typically have only 15-20% of the engineering and design completed before financing is obtained.

As important, the Alliance was working to finalize fixed price EPC agreements (inclusive of commissioning, start-up, and performance testing) with both the B&W/Burns & McDonnell joint venture and AL/CB&I partnership concerning their respective portions of the project prior to the suspension of activities by the DOE. These contractual arrangements serve as the basis for the EPC costs provided in Table 4-1. By completing this level of engineering, design and procurement readiness and by using this contracting approach, the Alliance was able to achieve greater certainty regarding the project's cost and schedule before financial close and the start of construction.

The ASU is not included in the capital cost estimate, but rather is assumed to be owned and operated by a third party with all of the required oxidant for the project being supplied on an "over the fence" (OTF) basis. The fixed charges and operating costs associated with the OTF approach are discussed further in Section 5.2.1.

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. 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. In many cases actual equipment purchase orders were fully negotiated and issued for limited notice to proceed in order to obtain final design information.
- Where vendor quotes were not obtained, costs were estimated based on experience and internal cost database information. This methodology was generally applied only to “stock” or “commodity” items that have a high degree of pricing certainty.
- Material take offs (MTO’s) for many bulk items, including site preparation, piping, electrical, structural steel (pipe racks) and concrete foundation work, were prepared specifically based on advanced engineering products ensuring a high degree of scope certainty. Historical unit prices were applied to these quantities to develop these costs.
- In order to secure the highest certainty regarding labor productivities, regional contractors who have serviced Ameren AER (the legacy power generation company) were used to develop estimates. For those items not covered by vendor quoted subcontracts, engineering and installation labor was estimated based on the division of responsibility, MTO’s, and schedule using in-house information and well-developed engineering drawings for each island supplier.
- Craft labor rates that reflect recent productivity experience in the area were gathered from the local union halls that have jurisdiction at the Meredosia site and the National Maintenance Agreement, which was adapted to the project and ratified by all 13 Unions who would have supplied labor.
- Island-specific EPC management reserve was included by each EPC contractor participant for their respective cost items.

4.1.1 Capital Cost Estimate - ASU

While the ASU was to be constructed and operated on an OTF basis, the capital costs associated with the ASU Island were developed by AL. Final total ASU capital cost was estimated at $255.2 million.

4.1.2 Capital Cost Estimate – Boiler, GQCS, and BOP

The capital cost estimate for the boiler and GQCS islands, along with the BOP systems was developed by BWM. Final total combined boiler and GQCS EPC cost was estimated at $134.5 million. Final total BOP EPC cost was estimated at $509.0 million.

The BOP estimate included costs associated with the ASU/CPU cooling tower, based on the original design capacity of 165.7 MMBtu/hr and 18,500 gpm. Due to process design development, the final cooling tower capacity was revised by Air Liquide late in Phase II to 177.4 MMBtu/hr and 19,750 gpm. To accommodate the higher heat duty, the required cooling tower fill area would need to increase and would result in an increase in overall cooling tower footprint. Cooling tower fan motor size would not change and circulating water pump sizing would not be impacted since Air Liquide advised that the cooling water system pressure drop in the ASU island decreased from 30 psid to 25 psid, thereby off-setting the increase in flow. However, circulating water piping size would need to be increased to accommodate the increased flow. The overall capital cost impacts associated with the larger cooling tower and increased system flow requirements were estimated to be $270,000.

Because of the late design change in the ASU/CPU cooling tower, along with the fact that the tower and associated ASU/CPU cooling system components were dedicated to the ASU and CPU islands and had essentially no interface with other BOP systems, the potential transfer of this system from BWM's BOP scope to Air Liquide's scope was being considered at the end of Phase II. Such a scope transfer would have included the following items:

- ASU/CPU Cooling Tower
- ASU/CPU Circulating Water Pumps
- ASU/CPU cooling tower basin and pump basin including piles
- Above ground and below ground circulating water piping to and from ASU and CPU Islands
- Electrical equipment, wiring, and raceway associated with the ASU/CPU Cooling Tower
- Chemical feed equipment dedicated to the ASU/CPU Cooling Tower
- Construction indirects

The BWM cost reduction associated with this scope transfer, including construction indirect costs, was estimated to be $3,000,000. The corresponding increase to the AL capital cost estimate had not been completed at the time of the closeout decision.

4.1.3 Capital Cost Estimate - CPU

The capital cost estimate for the CPU was developed by AL. Final total CPU capital cost was estimated at $168.9 million.

4.2 Operating Cost Estimate

4.2.1 Non-Fuel Operating Costs

Estimated fixed and variable non-fuel (i.e., non-coal) operating costs were developed by the Alliance in consultation with AEG, B&W and B&W's operating affiliate Delta Power Services (DPS), AL, URS, McGriff, and Area Disposal. The combined team drew on numerous years of plant operating experience and utilized information from similar projects to develop the operations and maintenance (O&M) staffing plans and non-fuel fixed and variable operating budgets for the project.

Estimated total non-fuel fixed and variable operating costs are presented in Tables 4-2 and 4-3. The methodology used for developing these non-fuel operating and maintenance costs is described below.

- O&M costs were estimated in current-year dollars and escalated on an annual basis over the proposed 20-year term of the PPA
- Staffing levels and costs were developed based on historical operations at Meredosia and data from the operation of facilities with similar systems and equipment. The O&M organization is expected to consist of approximately 71 permanent staff, plus 3 supervisory personnel provided by AL for the oversight of the CPU operation. Salary levels were based on existing Ameren and AL wage scales for managerial and bargaining unit employees.
- The staffing level and overall staffing costs for the boiler island, GQCS, steam turbine and BOP were reviewed by B&W's operations affiliate Delta Power Services (DPS) and found to be consistent with other facilities of this size and complexity that DPS either operates or has proposed to operate. Because the project will be operated by a contract operator such as DPS, a market based operator fee has been included in the budget.
- Annual routine maintenance costs for the boiler island, GQCS, steam turbine and BOP systems were based on industry norms for a plant of this size and complexity. This level of expenditure was reviewed by B&W's operating affiliate and found to be consistent with other facilities of this size and complexity that DPS either operates or has proposed to operate.
- Consumables, other than fuel and fuel related materials, include water treatment chemicals, reagents, and lubricants. The consumables were budgeted based on expected consumption rates.
- Fly and bottom ash (including the dry scrubber effluent) was to be transported and disposed at an offsite location. Unit costs were based on the waste disposal contract executed with Area Disposal Company (ADC) of Peoria, Illinois for transporting and disposing of the project's fly and bottom ash at ADC's Pike County, Illinois landfill.
- CO_2 transportation and storage charges were based on the Alliance's FEED study estimate for the Morgan County, Illinois pipeline and storage field.
- An estimate for purchased power costs for the project auxiliary loads was based on Ameren's distribution tariff rates, MISO transmission tariff rates and a forecast of wholesale around-the-clock electricity prices at the MISO Indiana Hub price node.
- MISO charges for the sale of power from the project into the MISO grid were based on its Federal Energy Regulatory Commission (FERC) approved tariff rates.

- Annual permit fees were based on Illinois Environmental Protection Agency regulations for air and National Pollution Discharge Elimination System requirements to maintain these permits.
- Insurance costs during the operating period were based on a budgetary quote from the Alliance's insurance consultant McGriff Seibels & Williams.
- Financing related costs during the operating period included an estimate of the cost of the bank's administrative agent, ongoing oversight by the bank's engineer and LOC commitment fees for working capital and the debt service reserve.

Table 4-2: Total Non-Fuel Fixed Operating & Maintenance Costs[1]

Fixed O&M (Nominal $000)															
Year	Power Block & CPU Supv Labor, Materials, & Contract Maint Labor	DOE Phase 4 Reporting Requirements	ASU OTF Charges	CPU Fixed O&M	CO2 Transportation & Storage	Major Maintenance & Asset Retirement Obligation Sinking Funds	Network Upgrade Facility Charges	Property Taxes	Insurance	Annual Permitting Fees	Operator Fee	Owner & Operator G&A	Working Capital & Debt Service LOC Commitment Fees	Other Lender Fees	Total Fixed O&M
2018	$ 3,117	$ 535	$ 7,320	$ 911	$ 3,195	$ -	$ 17	$ 299	$ 528	$ 66	$ 104	$ 987	$ 312	$ 91	$ 17,481
2019	$ 19,125	$ 1,667	$ 44,139	$ 5,589	$ 19,784	$ 1,814	$ 101	$ 1,791	$ 3,237	$ 402	$ 635	$ 5,824	$ 1,892	$ 559	$ 106,559
2020	$ 19,555	$ 1,667	$ 44,365	$ 5,715	$ 20,231	$ 1,814	$ 101	$ 1,791	$ 3,310	$ 411	$ 650	$ 6,247	$ 1,916	$ 571	$ 108,345
2021	$ 19,995	$ 1,131	$ 44,597	$ 5,843	$ 20,680	$ 1,814	$ 101	$ 1,791	$ 3,384	$ 420	$ 664	$ 6,316	$ 1,940	$ 584	$ 109,264
2022	$ 20,445	$ -	$ 44,833	$ 5,975	$ 21,148	$ 1,814	$ 101	$ 1,791	$ 3,460	$ 430	$ 679	$ 6,727	$ 1,965	$ 597	$ 109,967
2023	$ 20,905	$ -	$ 45,075	$ 6,109	$ 21,618	$ 1,814	$ 101	$ 1,791	$ 3,538	$ 439	$ 694	$ 6,856	$ 1,991	$ 611	$ 111,544
2024	$ 21,376	$ -	$ 45,323	$ 6,247	$ 15,049	$ 1,814	$ 101	$ 1,791	$ 3,618	$ 449	$ 710	$ 6,740	$ 2,017	$ 625	$ 105,860
2025	$ 21,856	$ -	$ 45,576	$ 6,387	$ 15,382	$ 1,814	$ 101	$ 1,791	$ 3,699	$ 459	$ 726	$ 6,869	$ 2,043	$ 639	$ 107,344
2026	$ 22,348	$ -	$ 45,834	$ 6,531	$ 15,722	$ 1,814	$ 101	$ 1,791	$ 3,782	$ 470	$ 742	$ 7,001	$ 2,071	$ 653	$ 108,862
2027	$ 22,851	$ -	$ 46,099	$ 6,678	$ 16,070	$ 1,814	$ 101	$ 1,791	$ 3,867	$ 480	$ 759	$ 7,143	$ 2,098	$ 668	$ 110,421
2028	$ 23,365	$ -	$ 46,369	$ 6,828	$ 16,426	$ 1,814	$ 101	$ 1,791	$ 3,955	$ 491	$ 776	$ 7,274	$ 2,127	$ 683	$ 112,001
2029	$ 23,891	$ -	$ 46,646	$ 6,982	$ 16,789	$ 1,814	$ 101	$ 1,791	$ 4,043	$ 502	$ 794	$ 7,408	$ 2,156	$ 698	$ 113,616
2030	$ 24,428	$ -	$ 46,929	$ 7,139	$ 17,161	$ 1,814	$ 101	$ 1,791	$ 4,134	$ 513	$ 811	$ 7,544	$ 2,186	$ 714	$ 115,267
2031	$ 24,978	$ -	$ 47,218	$ 7,300	$ 17,541	$ 1,814	$ 101	$ 1,791	$ 4,227	$ 525	$ 830	$ 7,684	$ 2,216	$ 730	$ 116,956
2032	$ 25,540	$ -	$ 47,513	$ 7,464	$ 17,930	$ 1,814	$ 101	$ 1,791	$ 4,323	$ 537	$ 848	$ 7,827	$ 2,247	$ 746	$ 118,683
2033	$ 26,115	$ -	$ 47,816	$ 7,632	$ 18,328	$ 1,814	$ 101	$ 1,791	$ 4,420	$ 549	$ 867	$ 7,974	$ 2,279	$ 763	$ 120,449
2034	$ 26,702	$ -	$ 48,125	$ 7,804	$ 18,734	$ 1,814	$ 101	$ 1,791	$ 4,519	$ 561	$ 887	$ 8,124	$ 2,311	$ 780	$ 122,254
2035	$ 27,303	$ -	$ 48,441	$ 7,979	$ 19,150	$ 1,814	$ 101	$ 1,791	$ 4,621	$ 574	$ 907	$ 8,277	$ 2,344	$ 798	$ 124,101
2036	$ 27,917	$ -	$ 48,764	$ 8,159	$ 19,575	$ 1,814	$ 101	$ 1,791	$ 4,725	$ 587	$ 927	$ 8,434	$ 2,378	$ 816	$ 125,989
2037	$ 28,546	$ -	$ 49,094	$ 8,342	$ 20,009	$ 1,814	$ 101	$ 1,791	$ 4,831	$ 600	$ 948	$ 8,595	$ 2,413	$ 834	$ 127,920
2038	$ 24,323	$ -	$ 41,193	$ 7,108	$ 17,054	$ 1,814	$ 84	$ 1,493	$ 4,117	$ 511	$ 808	$ 7,319	$ 2,041	$ 711	$ 108,577

[1]2018 and 2038 are partial years with 2 and 10 months of operation respectively.

Table 4-3: Total Non-Fuel Variable Operating & Maintenance Costs[1]

Non-Fuel Variable O&M (Nominal $000)									
Year	Consumables	Purchased Power (including ASU)	CO2 Transportation & Storage	MISO Charges / Power Marketing Costs	Fuel Oil	Lime	Trona	Ash Disposal	Total Variable O&M
2018	$ 187	$ 3,338	$ 201	$ 48	$ 1,475	$ 1,287	$ 57	$ 808	$ 7,401
2019	$ 1,145	$ 20,554	$ 1,218	$ 295	$ 2,606	$ 7,898	$ 353	$ 4,950	$ 39,019
2020	$ 1,351	$ 23,318	$ 1,374	$ 348	$ 2,696	$ 9,318	$ 424	$ 5,831	$ 44,659
2021	$ 1,381	$ 24,051	$ 1,386	$ 356	$ 1,782	$ 9,527	$ 440	$ 5,953	$ 44,877
2022	$ 1,600	$ 27,195	$ 1,545	$ 413	$ 1,840	$ 11,041	$ 515	$ 6,888	$ 51,038
2023	$ 1,636	$ 28,058	$ 1,559	$ 422	$ 1,904	$ 11,289	$ 531	$ 7,033	$ 52,432
2024	$ 1,673	$ 28,884	$ 1,573	$ 431	$ 1,967	$ 11,543	$ 552	$ 7,181	$ 53,804
2025	$ 1,711	$ 29,754	$ 1,588	$ 441	$ 2,052	$ 11,803	$ 566	$ 7,332	$ 55,247
2026	$ 1,749	$ 30,669	$ 1,603	$ 451	$ 2,121	$ 12,068	$ 581	$ 7,486	$ 56,729
2027	$ 1,789	$ 31,778	$ 1,618	$ 461	$ 2,195	$ 12,340	$ 596	$ 7,658	$ 58,435
2028	$ 1,829	$ 32,493	$ 1,634	$ 472	$ 2,274	$ 12,618	$ 612	$ 7,834	$ 59,765
2029	$ 1,870	$ 33,224	$ 1,650	$ 482	$ 2,359	$ 12,902	$ 628	$ 8,013	$ 61,127
2030	$ 1,912	$ 33,972	$ 1,666	$ 493	$ 2,443	$ 13,192	$ 653	$ 8,196	$ 62,526
2031	$ 1,955	$ 34,736	$ 1,683	$ 504	$ 2,533	$ 13,489	$ 670	$ 8,387	$ 63,957
2032	$ 1,999	$ 35,518	$ 1,700	$ 516	$ 2,628	$ 13,792	$ 687	$ 8,577	$ 65,417
2033	$ 2,044	$ 36,317	$ 1,717	$ 527	$ 2,723	$ 14,102	$ 705	$ 8,776	$ 66,913
2034	$ 2,090	$ 37,134	$ 1,735	$ 539	$ 2,829	$ 14,420	$ 722	$ 8,980	$ 68,449
2035	$ 2,137	$ 37,969	$ 1,753	$ 551	$ 2,940	$ 14,744	$ 740	$ 9,187	$ 70,023
2036	$ 2,185	$ 38,824	$ 1,772	$ 563	$ 3,062	$ 15,076	$ 767	$ 9,403	$ 71,653
2037	$ 2,235	$ 39,697	$ 1,791	$ 576	$ 3,184	$ 15,415	$ 786	$ 9,619	$ 73,303
2038	$ 1,904	$ 33,825	$ 1,509	$ 491	$ 3,010	$ 13,135	$ 671	$ 8,203	$ 62,748

[1]2018 and 2038 are partial years with 2 and 10 months of operation respectively.

As discussed previously, the supply of oxidant from the ASU would be provided by on an OTF contractual basis. In this approach AL, or another third-party vendor, would construct, own and operate the ASU and the project would pay a fixed facility charge plus an escalating operating charge, and power costs for the supply of oxidant. Budgetary estimates for these charges were provided by AL and other industrial gas suppliers. Based on this information the Alliance developed a set of commercial pricing terms for the fixed and variable charges in an OTF agreement. The resulting total annual and unit cost for oxidant over the 20-year term of the power purchase agreements are included in the costs presented in Tables 4-2 and 4-3.

4.2.2 Fuel (Coal) Costs

In 2013, indicative non-binding proposals to supply both PRB and Illinois basin coal were solicited from multiple fuel suppliers to supply the project. The project would consume approximately 600,000 tons of coal annually, with a blend of 60% high sulfur Illinois bituminous coal and 40% low sulfur PRB coal at an 85% capacity factor.

Coal from Illinois and PRB mines would be transported by rail to a Mississippi River dock, blended, loaded on barges, and shipped up the Illinois River to the Meredosia Energy Center barge unloading facility. The use of off-site blending enabled the project to have greater quality control of the fuel mix burned and reduce both on-site capital requirements and operating costs for coal operations.

Total annual expected coal fuel costs over the 20-year term of the PPA is summarized in Table 4-4.

Table 4-4: Annual Coal Consumption and Cost[1]

Year	Illinois, $/ton	PRB, $/ton	Illinois, $/MMBtu	PRB,, $/MMBtu	Blended Price, $/MMBtu	Coal Burned, tons/yr	Coal Cost, $000s/yr
2018	63.50	53.50	2.89	3.04	2.95	74,852	$ 4,413
2019	65.50	55.00	2.98	3.13	3.04	449,112	$ 27,273
2020	67.50	56.50	3.07	3.21	3.13	518,206	$ 32,388
2021	69.50	58.00	3.16	3.30	3.21	518,206	$ 33,307
2022	71.06	59.31	3.23	3.37	3.29	587,300	$ 38,597
2023	72.66	60.64	3.30	3.45	3.36	587,300	$ 39,465
2024	74.30	62.00	3.38	3.52	3.44	587,300	$ 40,353
2025	75.97	63.40	3.45	3.60	3.51	587,300	$ 41,261
2026	77.68	64.83	3.53	3.68	3.59	587,300	$ 42,189
2027	79.43	66.28	3.61	3.77	3.67	587,300	$ 43,139
2028	81.21	67.78	3.69	3.85	3.76	587,300	$ 44,109
2029	83.04	69.30	3.77	3.94	3.84	587,300	$ 45,102
2030	84.91	70.86	3.86	4.03	3.93	587,300	$ 46,117
2031	86.82	72.45	3.95	4.12	4.01	587,300	$ 47,154
2032	88.77	74.08	4.04	4.21	4.10	587,300	$ 48,215
2033	90.77	75.75	4.13	4.30	4.20	587,300	$ 49,300
2034	92.81	77.46	4.22	4.40	4.29	587,300	$ 50,409
2035	94.90	79.20	4.31	4.50	4.39	587,300	$ 51,543
2036	97.04	80.98	4.41	4.60	4.49	587,300	$ 52,703
2037	99.22	82.80	4.51	4.70	4.59	587,300	$ 53,889
2038	101.45	84.67	4.61	4.81	4.69	489,417	$ 45,918

[1]2018 and 2038 are partial years with 2 and 10 months of operation respectively.

4.3 Project Schedule

4.3.1 Introduction

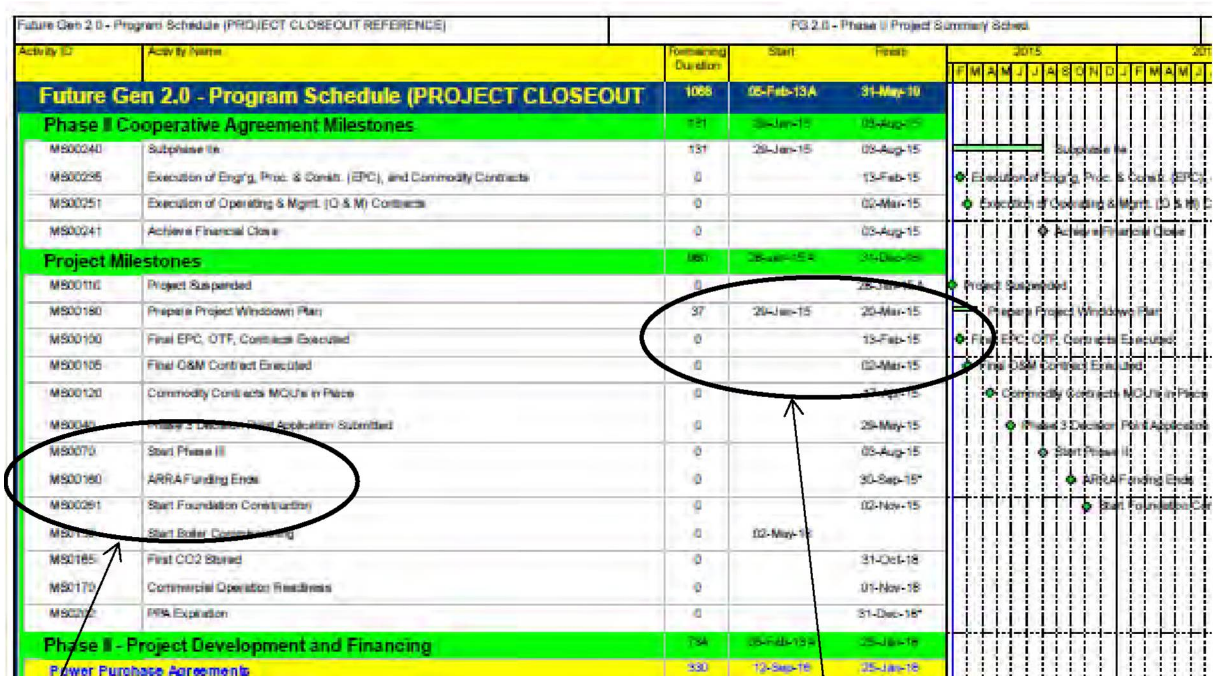
The project schedule for FutureGen 2.0 was developed early in Phase II and baselined in July 2013. The schedule included all work scope activities associated with engineering, procurement, construction, commissioning, start-up, and turnover for commercial operations.

The schedule includes the completion of Phase II activities, achievement of financial close, execution of Phase III EPC activities, start-up and initial operations, and Phase IV testing and data collection.

The following pages provide more information concerning the development of the schedule, major project milestones, and project file structure in the Primavera database as originally described in the project's Schedule Basis document.

The following screen shots provide a brief introduction to the information contained in the appendices:

<u>Project Summary Schedule</u>, (total of 13 pages in PDF format):



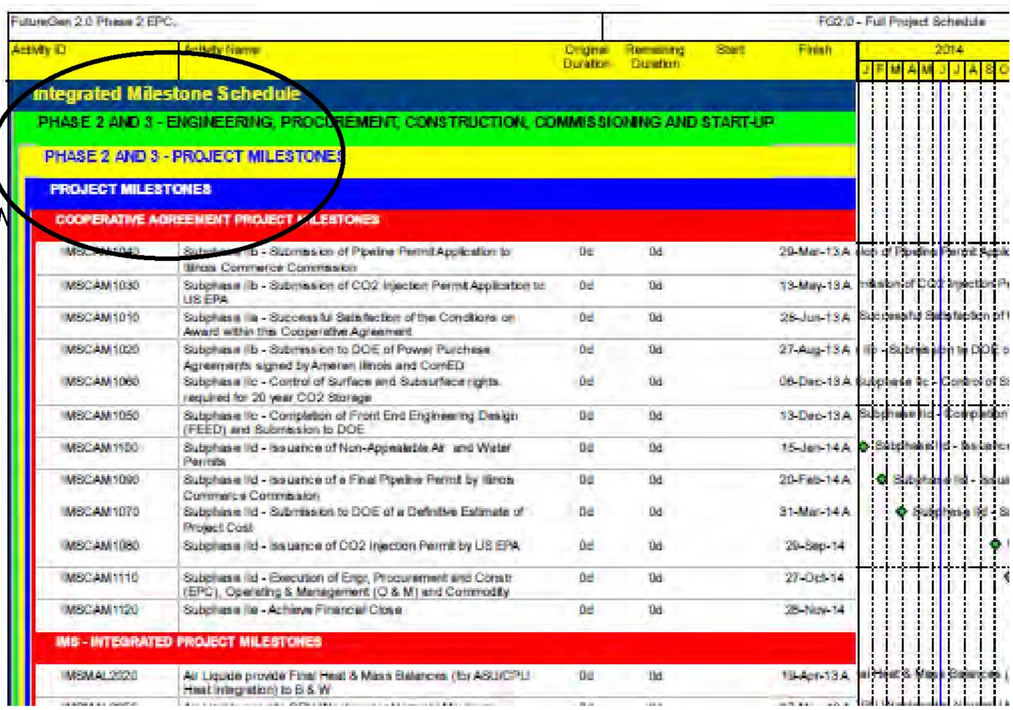
Future Gen 2.0 - Program Schedule (PROJECT CLOSEOUT REFERENCE) | FG 2.0 - Phase II Project Summary Sched

Activity ID	Activity Name	Remaining Duration	Start	Finish
	Future Gen 2.0 - Program Schedule (PROJECT CLOSEOUT	1068	05-Feb-13A	31-May-19
	Phase II Cooperative Agreement Milestones	131	29-Jan-15	09-Aug-15
MS00240	Subphase IIa	131	29-Jan-15	09-Aug-15
MS00295	Execution of Eng'g, Proc. & Constr. (EPC), and Commodity Contracts	0		13-Feb-15
MS00251	Execution of Operating & Mgmt. (O & M) Contracts	0		02-Mar-15
MS00241	Achieve Financial Close	0		03-Aug-15
	Project Milestones	[illegible]	[illegible]	[illegible]
MS00110	Project Suspended	0		28-Jan-15 A
MS00180	Prepare Project Winddown Plan	37	29-Jan-15	20-Mar-15
MS00100	Final EPC, OTF, Contracts Executed	0		13-Feb-15
MS00105	Final O&M Contract Executed	0		02-Mar-15
MS00120	Commodity Contracts MOU's in Place	0		[illegible]
MS0040	Phase 3 Decision Point Application Submitted	0		29-May-15
MS0070	Start Phase III	0		05-Aug-15
MS00160	ARRA Funding Ends	0		30-Sep-15*
MS00261	Start Foundation Construction	0		02-Nov-15
[illegible]	Start Boiler Commissioning	0	02-May-1[illegible]	
MS0165	First CO2 Stored	0		31-Oct-18
MS0170	Commercial Operation Readiness	0		01-Nov-18
[illegible]	PPA Expiration	0		31-Dec-18*
	Phase II - Project Development and Financing	794	05-Feb-13 A	25-Jan-18
	Power Purchase Agreements	330	12-Sep-16	25-Jan-18

Schedule Activity ID (unique per project file), Activity Name

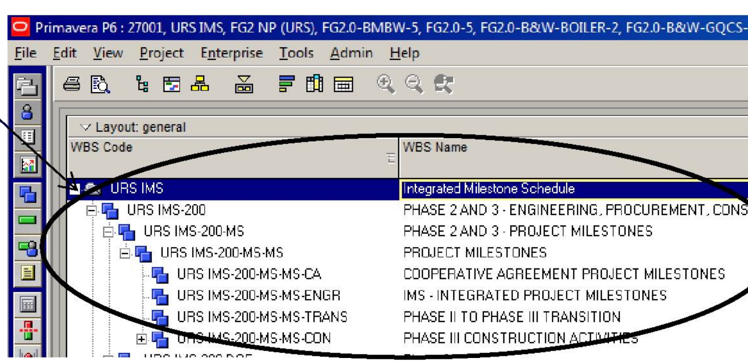
Forecast Dates as of Project Suspension

<u>Full Integrated Project Schedule</u> as Contained in the Compressed File, (total of 437 pages in PDF format):



This print includes all 8 project files as defined in the file structure shown below. The Blue Band indicates the beginning of a new schedule file; the various colored bands displayed hierarchically below the project file represent the WBS structure in the files.

Sample of the WBS Structure contained in the Primavera file. Notice the same structure in the Full Project Schedule print.



4.3.2 Schedule Status

DOE direction that the agency would suspend its cost-share was received in January 2015 after about 7 months in an extended Phase II to allow for various appeals and interrelated contracting issues to be resolved. The last update of the Integrated Project Schedule was conducted in June 2014. For the period July 2014 to January 2015 only the Program Summary Schedule (project ID: FG2 NP (URS)) was maintained to assist planning for execution of limited near-term efforts and forecasting project major milestones. Much of the inter-project logic ties that formed the backbone of the IPS were removed during this 7-month period.

The information contained in this document is meant to convey the IPS structure as it existed in June 2014 and depicts high-level milestones had the project continued and achieved the start of Phase III in August 2015.

4.3.3 General Project Schedule Information

4.3.3.1 Executive Summary

The schedule for the FutureGen 2.0 Oxy-Combustion Large Scale Test Project has been developed as an IPS. There are 8 schedule files in the Primavera database that are managed independently by each contractor and contain activities that represent the scope to be executed by the respective contractor. There are several points of interface between the contractors, where information needs to be exchanged or physical interfaces at the jobsite. Interfaces that will affect the schedules are represented by logic ties to/from individual schedule files. The schedules are developed to a Level 3 detail for the engineering and procurement scopes and Level 2 for construction.

Table 4-5 a summarization of the IPS and the scope represented within each file.

Table 4-5: Integrated Project Schedule and Scope

Primavera Project ID	Primavera Project Name	Managing Contractor	Scope Summary	Apprx # Activities
FG2.0-B&W-BOILER-2	282Q - Future Power Gen 2.0 167MW RBC Boiler - Phase 2A Submit to URS	Babcock & Wilcox	**Engr. & Proc** for Boiler	3300
FG2.0-B&W-GQCS-2	282R - Future Gen 2 - GQCS WIP - Phase 2A - Sent to URS	Babcock & Wilcox	**Engr. & Proc** for GQCS	1500
FG2.0-5	BMCD - Phase 2.0 OXY-COMBUSTION LARGE SCALE TEST PROJECT	Burns & McDonnell	**Engr. & Proc** for Balance of Plant (BOP) Equipment, Site Prep	1700
FG2.0-BMBW-5	Phase 2.0 OXY-COMBUST LARGE SCALE TEST PROJECT - EPC Interface File	Joint Effort: Burns & McDonnell and Babcock & Wilcox	**Milestone** schedule linking logic between Burns & McDonnell and Babcock & Wilcox schedules	200
E001490-EARLY Case-1	1490-1 FUTURE GEN 2.0 LEVEL 2 Development Const - Phase 3 / FGA Early Work CURRENT	Burns & McDonnell	**Construction** schedule for: overall site, Boiler, GQCS, and BOP	400
FG2 NP (URS)	Future Gen 2.0 - Program Schedule	URS	**Program Summary** schedule, Alliance scope, Owner Engineer executed or managed scope for specific Engr, Proc. & Construction associated with existing plant	750
URS IMS	Integrated Milestone Schedule	URS	**Milestone** schedule linking logic between project files	100
27001	FutureGen 2.0 Phase 2 EPC	Air Liquide	**Engr, Proc & Construction** for ASU and CPU	4000

4.3.3.2 Project Scope

The Oxy-Combustion Large Scale Test Project was to build a new oxy-combustion coal-fired boiler, Gas Quality Control System (GQCS), oxygen producing ASU, CPU, and necessary infrastructure to support operation and power production. The new plant was to be constructed on the site of an existing non-operating power plant owned by Ameren located in Meredosia, IL. Many of the existing plant structures were to be repurposed for use in the new power plant.

Prior to starting to build the new power plant and associated carbon capture equipment, the following structures were required to be demolished and removed from site: existing oil-fired boiler #6 in power plant unit #4; unit #3 ESP building; cooling tower; 8 warehouses; and several miscellaneous structures including wells, fuel oil pipeline, transmission towers, aux boiler, condensate tank, and PAC silo. A selective construction effort was completed during Phase II to re-route and raise existing high voltage transmissions lines that were crossing the site in order to clear the overhead area to be occupied by the proposed new project.

4.3.3.3 Purpose and End Use of the Schedule

This schedule is the best representation of the project plan as of this date. If the project is released from suspension this schedule and schedule basis will be further refined.

The start of Phase III would have indicated availability of full project funding and permitting and released the balance of detailed engineering; full material, equipment, and services procurement; and the start of site demolition and construction. If the project had not been suspended, the target for financial close was August 2015. Upon commencement of Phase III, a ramp-up period should be anticipated to allow for re-staffing and re-start of project activities.

4.3.3.4 Schedule Milestones

Table 4-6 represents a selection of key milestones and the current forecast dates based on a planning basis of financial close and start of boiler demolition by August 2015. Contractual milestones, as they are agreed to, will be reflected in the baseline schedule to be developed after financial close during the beginning of Phase III.

Table 4-6: Key Milestones

MILESTONE	DATE
Start Air Permit Preservation Construction (Stack Fdn)	August 2014
Financial Close / Begin Phase III	August 2015
Begin Demo of Old Unit 4 Boiler	August 2015
Complete Major Demo of Existing Plant	February 2016
Begin Piling and Foundations for New Power Plant	November 2015
Begin ASU / CPU Piling and Foundations	June 2016
Boiler First Fire on Oil	May 2018
Boiler First Oxy-Combustion Fire	September 2018
First Industrial Production Gaseous Oxygen (FIP GOX)	July 2018
First CO_2 Available to Pipeline	November 2018

Commercial Operation Readiness Date	November 2018
Plant Commercial Operation (Contract)	November 2018
Power Purchase Agreement Expiration	December 2018

4.3.4 Project Execution Strategy and Responsibilities

The FutureGen Alliance was in the process of negotiating final EPC Contracts with B&W and Burns & McDonnell (BWM), as well as AL for the final engineering, material procurement, and construction management of the oxy-combustion power plant. URS was contracted as the Owner's Engineer and was to manage the legacy equipment scope of work based an EPCM approach. The following is a general distribution of the project scope:

- B&W – Final engineering for the boiler and GQCS systems, and equipment procurement for these systems.
- Burns & McDonnell – Final Engineering for the balance of plant systems and equipment procurement for these systems.
- Air Liquide - Final Engineering for the ASU and CPU, and equipment procurement for these systems. Also includes construction and commissioning for these systems.
- BWM – Construction of the power plant and GQCS, balance of plant systems, site preparation, underground utilities, and commissioning for these systems.
- URS – Owner's engineer support. EPCM of specific legacy plant systems, and some early site construction activities. Overall coordination of commissioning activities by plant area.

4.3.5 Work Breakdown Structure

Each schedule file utilizes a WBS structure within Primavera that aligns with the contractor's corporate requirements. There is an activity coding structure within the IPS to define a cohesive project-wide WBS structure, referred to as the Alliance WBS. Development of the Alliance WBS structure for Phase III was not finalized and is not completely represented in the schedule.

4.3.6 Planning Highlights

4.3.6.1 Engineering and Project Management

The following were the critical items that had become schedule drivers:

- Resolution of an appeal related to the PPA and resolution of collateral suit by the Sierra Club regarding the final and effective construction air permit
- Completion of the nearly finalized EPC Contracts with BWM and AL

Achieving financial close, which has as a prerequisite resolution of litigation and contracts.

4.3.6.2 Long Lead Procurement

Due to long lead times for manufacturing and delivery, the following equipment packages are critical or near critical drivers to achieving the project Commercial Operation Date (COD):

Boiler

- Pressure Parts: Issue PO to 1st Shipment on Site = 16 months
- Purchase orders were ready to be placed 2 weeks after approval from the DOE and amendment to the ESA contract. Once approved, vendors will be released on raw material and the material will be shipped to the pressure part fabricator for fabrication and eventual shipment to the jobsite.

ASU

- E01 Main Heat Exchangers, E03 Subcooler: Issue PO to Arrive on Site = 22 months
- Cold Boxes, Vessels, Pump Boxes, Air Purification System: Issue PO to Arrive on Site = 23 months

CPU

- Compressors (Wet Feed Gas, HP CO_2): Issue PO to Arrive on Site = 23 months

4.3.6.3 Construction Critical Path

The critical, or near critical, paths through construction are at an accuracy consistent with a Level 2 schedule. The Level 2 construction schedule is developed to identify sequence and duration of the plant construction efforts in sufficient detail to support estimate validation and ensure feasibility of the plan. This will serve as the framework for developing a level 3 schedule early in Phase III.

The same long lead equipment packages drive critical paths to the major milestones for First Fire of Boiler, Oxygen ready to support oxy-combustion, and the CPU Ready to Accept CO_2.

4.3.6.4 Start-up and Commissioning

The start-up and commissioning schedule is developed to a summary level in alignment with the pass gates as defined in Exhibit N in the EPC contracts. During the next project phase the schedule will be detailed to show a plan for achieving the following pass gates:

- Pass Gate 1 – Utility Systems Ready for Commissioning
- Pass Gate 2A – ASU Ready for Oxy-Combustion
- Pass Gate 2B – Boiler Ready for Oxy-Combustion
- Pass Gate 3 – Boiler Ready for CPU Operations
- Pass Gate 4 – CPU Ready for Pipeline Operations
- Pass Gate 5 – Commercial Operation Date

4.3.7 Assumptions, Clarifications, Qualifications, and Allowances

4.3.7.1 Assumptions

- Current construction schedule assumes a single shift, 5 day work week, 10 hour days. Select double shifts have been assumed during Boiler tube weld-up only.
- No allowances have been included in schedule duration to account for productivity impacts due to weather.

4.3.7.2 Risk / Opportunities

- Availability and cost of labor could add cost and extend schedule.
- High economic activity in North American industrial sector, and/or improvement in the world economy, could substantially increase equipment and bulk material delivery schedules.
- Current plan assumes equipment fabrication and delivery durations are not impacted by any delays in the vendor engineering effort.
- Unknown vendor shop capacity could impact deliveries and durations for fabrication of all equipment.

5.0 Project Risk and Opportunity Assessment

5.1 Project Risks

5.1.1 Project Definition Rating Index

During Phase I, a Project Risk Matrix was developed to track various technical, economic, and permitting uncertainties identified for the Project. Additionally, a formal Project Definition Rating Index (PDRI) was performed in both Phase I and Phase II and included the Alliance, URS, AL, Burns & McDonnell and (B&W. PDRI is an assessment process developed by the Construction Industry Institute (CII) to assess the state of a project's development and project risk. As project's move through their development cycle they are scored, with a lower score being better. The Phase II assessment yielded a score of 330/1000, which is consistent with a best-in-class project that has completed a FEED. DOE's substantial support of a greater than typical pre-construction level of design is reflected in this score as it significantly reduced project risk. The Phase II assessment results also reflect a step-change advancement over the Phase I score of 553/1000. Table 5-1 reflects the major categories that were assessed and Phase I and Phase II ratings. A lower score indicates improved development and less project risk.

Table 5-1: Project Definition Rating Index (PDRI)

PDRI Category	Phase 1	Phase II
	553/1000	330/1000
A. MANUFACTURING OBJECTIVES CRITERIA	28/45	27/45
B. BUSINESS OBJECTIVES	79/213	39/213
C. BASIC DATA RESEARCH & DEVELOPMENT	38/94	28/94
D. PROJECT SCOPE	59/120	42/120
E. VALUE ENGINEERING	18/27	8/27
F. SITE INFORMATION	47/104	25/104
G. PROCESS/MECHANICAL	130/196	63/196
H. EQUIPMENT SCOPE	18/33	11/33
I. CIVIL, STRUCTURAL, & ARCHITECTURAL	17/19	12/19
J. INFRASTRUCTURE	18/25	13/25
K. INSTRUMENT & ELECTRICAL	40/46	20/46
L. PROCUREMENT STRATEGY	11/16	5/16
M. DELIVERABLES	7/9	4/9
N. PROJECT CONTROL	10/17	8/17
P. PROJECT EXECUTION PLAN	33/36	29/36

From the PDRI, the following areas were known to require further work, which could have reduced the PDRI score further prior to construction (see Table 5-2):

Table 5-2: PDRI Focus Areas

A1. Reliability Philosophy	RAM analysis was still needed
A2. Maintenance Philosophy	Input from Delta Power Services (one of the plant's contract operators) was needed, and AL Large Industries input & experiences from Callide & Ciuden require full incorporation into the project.
A3. Operating Philosophy	Operating companies (AL & Delta Power) were to begin providing input for joint operations, commissioning & startup.
D6. Project Schedule	The start date for construction was in-flux, and further work was needed on coordinating the construction to commissioning transition.
F6. Fire Protection & Safety Considerations	HAZOPs needed to be done, and finalization of the plant fire protection design basis was needed.
G10. Line List	P&ID's were in the CAD system - Line list is output from CAD system.
G11. Tie-In List	Tie Points had been identified - still needed to finalize process conditions, physical connection locations, and details.
G12. Piping Specialty Items List	P&ID's were in CAD system - Specialty list was output from CAD system.
G13. Instrument Index	P&ID's were in CAD system - Instrument list was output from CAD system.
H3. Equipment Utility Requirements	Power consumption portion of Bid tab analysis, inventory of utility requirements had been incorporated into P&ID development. Still needed to incorporate final vendor data.
I1. Civil/Structural Requirements	"Not to exceed" loads had been incorporated into the design. Needed to compare against final loads.
I2. Architectural Requirements	Aesthetics had yet to be considered. Functional aspects had been determined, needed to conform to final equipment sizes.

J2. Loading/Unload./Storage Facilities Req'mts	Agreement between the parties regarding the use laydown areas and improvements to barge unloading facilities needed to be formalized.
J3. Transportation Requirements	Heavy hauls and heavy Equipment - needed to perform a joint review of the barge facility and haul roads.
K1. Control Philosophy	System Requirements & Specifications (B&W) and SIS (AL) still needed to be done. Phase II Dynamic analysis was nearly complete.
K2. Logic Diagrams	Not started for B&W. AL utilizes product-based design for ASU
K3. Electrical Area Classifications	Still needed to be reviewed in HAZOP and approved.
K6. Instrument & Electrical Specifications	Field construction specifications had yet to be done.
L2. Procurement Procedures and Plans	ARRA contractual flow-down requirements were a concern. Needed fully conforming with EPC contract terms.
M2. Deliverables Defined	Final Review of Deliverables Matrix.
M3. Distribution Matrix	Final Review of Distribution Matrix.
P1. Owner Approval Requirements	This was more complex than just owner's approval requirements - needed to include DOE, bankers engineer, FGA, owners engineer, Delta Power and Air Liquide Operations.
P2. Engineering/Construction Plan & Approach	At the time the PDRI was performed, the form of EPC contract (Firm Lump Sum vs Cost Reimbursable Target Price) had yet to be defined.
P3. Shut Down/Turn-Around Requirements	Target Time Between Plant Outages was 18 Months - Power line relocation had been timed to match Ameren transmission line outage schedule. Still had to coordinate ongoing construction and final tie-in.

During the Phase II schedule there were several key risk items that had been identified, recognized and in all cases there had been mitigation plans in progress to minimize the impacts, or were under negotiation prior to the closeout decision. The following list is not in any specific order of priority.

5.1.2 Commercial:

- EPC Contracts

  Executing EPC lump sum contracts with acceptable liquidated damages for process performance and schedule.

- Integration of equity partners into design process and plan for operation

  The equity partners had begun the process of due diligence on the project design, as well as the staffing plan for long term operations. Discussions were commencing to define the role of the operations contractor.

5.1.3 Financial:

- Extension of ARRA funding deadline

  The inability to expend ARRA funding prior to the September 30, 2015 deadline, or to secure an extension.

- Private Funding

  Obtaining private financing to augment DOE ARRA funding. Final due diligence was on the cusp of launch when the closeout decision occurred.

- Performance Guarantees

  Negotiations were reaching completion with the technology providers to provide performance guarantees with substantial liquidated damages such that the Power Purchase Agreement (PPA) rate caps and other PPA requirements could be met on a long term basis.

5.1.4 Litigation:

- Sierra Club Citizen Complaint

  The project has secured a final and effective air permit, which was un-appealable through the normal permitting process. The Sierra Club filed a citizen complaint asserting a new PSD air permit was needed. The project secured a favorable court ruling from the Illinois Pollution Control Board. Sierra Club was appealing their loss at the time the closeout decision occurred.

- Challenges to PPA

  The project had secured PPAs for 100% of the plant's output. The PPAs remain in full force and effect. Project opponents challenged the Illinois Commerce Commission's Authority to approve the PPAs. The Illinois Court of Appeals ruled in the project's favor. The losing appellants have refiled their appeal with the Illinois Supreme Court where it was pending at the time a cooperative agreement close-out decision was made.

5.1.5 Schedule

- Start construction to meet Air Permit

  Construction work had been "commenced" in time to satisfy the requirements of the air permit. As the project schedule extended (e.g., due to appeals and other issues), it may have been necessary to secure additional funding for additional early construction work to maintain the air permit.

- Project schedule to support PPA Requirements

  There was concern that the latest change in the financial close date and the technology providers' guaranteed project completion dates would leave inadequate float before the PPA end date necessitating an extension from the Illinois Commerce Commission.

- Construction barge shipment timing logistics

  The shifting date for the financial close, and the subsequent shift in construction start date created uncertainty regarding the timing of barge shipments in relationship to seasonal river water levels.

- Long-lead procurements

  There were boiler pressure parts that were to be fabricated from metals having a long lead time which would have required to be purchased upon the financial close date in order to maintain project schedule

5.2 Process Risks

5.2.1 General

This was to be a first-of-a-kind demonstration of the integration of disparate technologies. Although the risks within the boundaries of a technology provider are reasonably well known, the challenge of a project of this type is to insure that the connected technologies operate well together, not only in steady state operation, but also during startup and shutdown, and that they can respond appropriately to interruptions, transients, and transitions.

The work that began to identify process risks during Phase I of the project was continued in this phase, both to address the risks which had previously been identified, as well as to identify and address new risks.

The following risks had been previously identified during Phase I of the project:

NOx Emissions during Extended Air Fired Operations

Risk:	Mitigation:

Since this project was to be a first-of-a-kind commercial demonstration of the oxy-combustion technology, initial startup difficulties were to be anticipated - especially with regard to ASU and/or CPU operation - that would prevent continued oxy-combustion operation and require possible extended or unexpected air-fired operation. Since NOx was to be removed in the CPU, and since the CPU can only operate in oxy-combustion mode, there was a potential for long term NOx emission levels to reach or exceed permit levels, as well as for CO_2 capture rate requirements to not be achieved.	The Phase II design and engineering has quantified the emissions to be expected. Additionally, the potential causes of ASU or CPU failures that could prevent the plant from operating in oxy-combustion mode have been further evaluated and substantiated by the dynamic modeling results. Other mitigation strategies would have included increasing the CPU's percent capture of the CO_2 in the entering flue gas and longer campaigns of operation between outages to minimize the amount of NOx and CO_2 released during start-ups and shut downs. Additional mitigation work would still have been required in Phase III to reduce either the severity or the likelihood of the various upsets.

Toxicity of Fugitive CO_2 Emissions

Risk:	Mitigation:
Fugitive CO_2 emissions present a safety hazard, primarily due to the risk of personnel asphyxiation and CO_2 poisoning (aka hypercapnia).	The number of enclosed areas adjacent to the boiler and GQCS equipment was minimized to the extent possible. Phase II design development specifically addressed this risk in a number of areas. As would be typical with any coal fired power plant, the following precautionary measures were to be taken: • minimize low-lying areas where flue gas could be confined • minimize flue gas leakage from flues and equipment • provide normal ventilation for enclosures/buildings containing flue gas or CO_2 conveyances • purge the gas path with air before entering for maintenance, and check O_2 and CO_2

	levels whenever entering or working in a confined space. In addition to these precautionary measures, an advanced CO_2 monitoring system was to be installed in the buildings where CO_2 accumulation was a concern. This CO_2 monitoring system would have alarmed and prevented personnel access when unsafe conditions existed within the building. The CPU was also modified to combine individual vent streams into a common vent manifold which would have discharged at the top of the main stack. Further design development would still have been required to fully mitigate this risk.

Limited Data Regarding Radiant and Convective Heat Transfer in a CO_2 Rich Atmosphere

Risk: Radiant and convective heat transfer calculations for CO_2 rich flue gas (vs. typical N_2 rich flue gas in air-fired applications) remain unconfirmed due to the lack of operational data on a commercial scale boiler. Consequently, uncertainty remains regarding the design and performance of boiler and GQCS equipment.	Mitigation: Boiler, GQCS, and accessory equipment design has been based on an expanded range of operational variations and upset conditions vs. what would typically be used for an air-fired boiler. Designing for these expanded ranges would have allowed for additional flexibility in the gas recycle rate through the system, which would have served to mitigate any unfavorable heat transfer behaviors.

Chemical Composition of CPU Intercooler Condensate:

Risk: The composition of the process condensate from the CPU interstage coolers, which contained significant quantities of nitric acid and mercury, presented specific water treatment challenges to avoid potential permitting issues.	Mitigation: The design basis for the wastewater treatment system included consideration of the CPU wastewater stream, and the Phase II wastewater treatment system was designed to adequately handle this wastewater.

5.2.2 Overall Plant Process Risks

The detailed design development performed in Phase II, along with the Interface Process Safety and Operability Review (IPSOR) or "HAZID" process uncovered a number of additional process risks, including the following:

Boiler Flue gas CO_2 Concentration

<table>
<tr><td>Risk:

Air influx into the negative pressure sections of the Boiler/GQCS gas path could have increased the gas volume and reduced the CO_2 concentration in the flue gas being sent to the CPU. This could have significantly reduced the CO_2 capture rate of the CPU, necessitating the increase in size and power consumption of the CPU CO_2 compressor, and a loss of efficiency in the non-condensable gas treatment membranes.</td><td>Mitigation:

The primary cause of dilution of the CO_2 concentration in the flue gas to the CPU was air infiltration, whether intentional or unintentional. Other possible causes were identified, but air infiltration was the most significant.

• Intentional air infiltration sources include air streams used for equipment sealing and/or cooling. To mitigate the dilution effect of these sources, dried and filtered flue gas was to be used instead of air wherever possible. Dried and filtered flue gas was also to be used for the baghouse back-pulsing to clean the filter bags.

• Unintentional air infiltration sources include air that leaks into the process via flue, duct and other equipment due to imperfect sealing and the pressure differential between ambient surroundings and the process stream. Mitigating measures for these unintentional infiltration sources included the following:

o moving the balance or "zero" pressure point further downstream so that the amount of flues and equipment operating at negative pressure, where air infiltration occurs, would have been minimized</td></tr>
</table>

	o Implementation of additional Quality Assurance methods and procedures during fabrication and erection to minimize potential leakage paths.

Effect of Fugitive CO_2 Emissions on Overall Plant Capture Efficiency

Risk:	Mitigation:
Fugitive CO_2 emissions from DCCPS cooling tower, along with emissions/leakage from other process locations where positive pressures exist, would have a negative effect on the overall CO_2 capture rate of the plant.	To help maintain the CO_2 capture rate of the plant, fugitive CO_2 emissions were to have been controlled through Phase III design improvements, including a possible increase of the design CPU capture rate. Additionally, specific Quality Assurance procedures during fabrication and erection and proper maintenance procedures to minimize leakage points were to have been implemented.

Loss of Oxidant Flow

Risk:	Mitigation:
Loss of the gaseous oxidant supply from the ASU to the boiler for more than two seconds would cause a Master Fuel Trip (MFT).	The provision of a backup supply of Oxidant would have necessitated the continuous vaporization of Liquid Oxygen during operation, at a significant power consumption penalty. Air separation units are an inherently reliable process. Mitigation measures would have included reliability enhancement in the equipment selection, instrumentation and controls of the ASU.

Interruption of Pipeline Availability

Risk:	Mitigation:

If product CO_2 could not be delivered to the sequestration pipe line, a Master Fuel Trip would result, followed by a delay of 12 hours or more before the boiler would be able to restart.	The design was modified during Phase II to include a separate flue within the main stack to provide an alternate CO_2 vent flow path in the event that the pipeline could not accept CO_2 from the CPU. This would prevent a Master Fuel Trip on the boiler and allow it to continue to operate or at least shut down in a controlled manner. This alternate CO_2 vent also addressed dispersion and personnel safety concerns since the CO_2 would have been exhausted at the top of the main stack.

Integration of CPU Compressor into draft Controls

Risk:	Mitigation:
The CPU compressor is a high energy machine that, unless tightly controlled, is capable of imploding the boiler due to small pressure variations within the CPU.	A dynamic model was created and used to study the response and interaction of the boiler and CPU operation to various operational upsets. Additional controls were to be integrated into the model and additional evaluations completed in Phase III, with the intent of further modifying the final design based on the model predictions. Additionally, an implosion door was to be installed in the system in order to protect the boiler flues from implosion.

5.2.3 Boiler & GQCS Process Risks

Fouling of Boiler

Risk:	Mitigation:
Due to lack of operational data on a commercial scale boiler, slagging and fouling characteristics of the coal ash onto the furnace and convection bank heat transfer surfaces in	Provisions in the boiler design have been made for the installation of additional sootblowers if boiler operation were to indicate that they were needed. Additionally, an intelligent sootblowing system would have been used to monitor the cleanliness of the

the boiler with CO_2 rich (vs. N_2 rich) flue gas composition remain uncertain.	furnace and convection pass banks. This system was to have operated the appropriate sootblowers and Hydrojets needed to maintain the overall cleanliness of the boiler.

Fuel Deposition in Oxidant Lines

Risk: Potential deposition within the oxidant piping of fuel or unburned combustibles contained in the coal ash would create a fire hazard or explosive situation when the oxidant flow was re-established.	Mitigation: Boiler design was to have included backflow preventers and positive isolation of the piping when the pressure in the oxidant supply header drops below a prescribed set point, to prevent deposition of combustible material in the oxidant piping.

5.2.4 CPU Process Risks

CO_2 Product Temperature

Risk: Possible high temperatures in the final product CO_2 delivered to the pipeline, as a result of the process temperature increase across the CO_2 Product Pump, could result in unacceptably high soil temperatures above the underground CO_2 pipeline to the sequestration site.	Mitigation: A CO_2 product cooler was added to the design in the late stages of Phase II. Further design details were to be developed as part of Phase III.

Mercury Deposition

Risk: Possible elemental mercury deposition in the Cold Box could cause plugging and metallurgical issues within the heat exchangers.	Mitigation: Air Liquide had a mitigation plan to be implemented during Phase III, but the details are proprietary.

Formation of Dry Ice at CO_2 Vents

Risk:	Mitigation:
Due to JT cooling, venting of the high pressure product CO_2 results in extremely low gas temperatures and potential ice crystal formation ("snowing") in the CO_2 vent stream, which could result in low-temperature embrittlement or plugging of CO_2 piping.	Mitigation measures included the following: • The CPU was designed to vent product CO_2 from upstream of the final aftercooler where higher temperatures exist, thereby minimizing the final temperature reduction after venting. • CO_2 vent streams were consolidated into common larger diameter headers where possible, minimizing possible failure points and the potential for plugging. • The design included provisions for pressurizing the vent pipeline with N_2 prior to admitting CO_2, thereby diluting the vent stream and increasing the final bulk vent gas temperature.

CO_2 Compressor Sizing

Risk:	Mitigation:
The CPU CO_2 Compressors have little or no turndown capability, and due to uncertainty regarding flue gas composition as a result of potential air infiltration concerns, have been oversized to handle the worst case situation, resulting in reduced overall net plant power generation and consequent long term economic impacts.	Beyond the mitigation measures previously discussed for the boiler and GQCS to minimize air infiltration, the following potential CPU and GQCS design modifications were identified in Phase II and were to be further evaluated in Phase III to allow a reduction in the CO_2 compressor size. • Modify the design to accommodate "doping" of the flue gas using stored or recycled product CO_2 when inlet flue gas

	composition fell outside the CO_2 compressor design range. • Modify the design to allow partial venting of the flue gas upstream of the compressor when composition fell outside the CO_2 compressor design range.

5.3 Plant Cost, Reliability, Operability, and Maintainability

The objective of Phase II was to produce a definitive estimate for a well-developed plant design. As such, most opportunities for potential improvements in overall plant cost, reliability, operational flexibility, and maintainability had been investigated and either 1) incorporated into the design, 2) rejected or 3) set aside for consideration after the plant, as designed, was operational. Further evaluation and implementation of opportunities in this third category was to have been pursued during Phase III.

The most significant potential improvement requiring continued evaluation was the upgrade of the existing steam turbine to accommodate a wider range of oxy-combustion plant operation. The existing turbine steam path limitations concerning flow, pressure, and temperature changes that were to be accommodated with the oxy-combustion cycle, continued to be studied. While the physical condition of the turbine was adequately assessed in Phase II and deemed satisfactory for continued use in oxy-combustion operation, the equipment performance degradation could not be confirmed until the unit was placed in operation. Furthermore, turbine upgrades had been proposed by the OEM, Siemens-Westinghouse, that appeared to significantly improve turbine performance for a relatively low capital investment. These upgrades were not pursued further in Phase II as the existing turbine condition was sufficient to support the operational requirements in the PPA and the DOE project objectives. This resulted in substantial capital cost savings.

The Interface Process Safety and Operability Review (IPSOR), which was performed in Phase II, was directed toward identifying any process design issues which could have added substantial cost if identified at a later date. The ISPSOR also identified a number of Reliability, Operability, and Maintainability enhancements, which were incorporated in the design.

Two additional studies were to have been performed during Phase III, which would have identified other opportunities to improve the project economics through enhanced reliability, operability, and maintainability:

- **RAM analysis** – A numerical evaluation of the overall plant reliability, taking into account the reliability of plant components, and the level of redundancy. This type of analysis often results in cost savings through the substitution of high reliability non-redundant equipment for low reliability, redundant equipment.

- **HAZOP** – The HAZOP (Hazards and Operability Review) was to have been performed in Phase III, and would have included the equity partner. When properly performed, these reviews often identify minor modifications to the design which improve the reliability and maintainability of the plant, and improve project economics.

6.0 Permitting and NEPA

6.1 Permits

The Alliance, Ameren, and URS jointly submitted an air construction permit, NPDES operating permit and state wastewater construction permit applications to IEPA. Final permits were issued by IEPA during Phase II.

The Alliance and URS jointly applied for and received the following:

- US Army Corps of Engineers Nationwide Permit 33
- FAA Determination of No Hazard to Air Navigation
- IEPA Section 402 NPDES Construction Permit
- U.S. EPA and IEPA Waste Identification Numbers

A permitting action plan (permit matrix) was to be developed to outline activities associated with the above listed permits and other required permits and activities as part of the FutureGen 2.0 Project. Colored status indicators were to be utilized to show importance and completeness of project related activities.

6.2 Environmental Information Volume

Based on direction from DOE at the January 26, 2011 meeting in St. Louis, URS provided information to DOE's Environmental Impact Statement (EIS) contractor, Potomac Hudson Engineering (PHE). PHE had conveyed to URS that all major information requirements for the EIS have been met.

6.3 Environmental Impact Statement

The EIS had evaluated the potential impacts associated with DOE's proposed action to provide financial assistance to the Alliance for the FutureGen 2.0 Project, including the direct and indirect environmental impacts from construction and operation of the proposed project. DOE's proposed action would have provided approximately $1 billion of funding, primarily under the American Recovery and Reinvestment Act, to support construction and operation of the FutureGen 2.0 Project.

On May 23, 2011, DOE published a Notice of Intent (NOI) to prepare an EIS in the Federal Register (FR) under Docket ID No. FR Doc. 2010–12632 (76 FR 29728). The NOI initially identified potential issues and areas of impact that would have been addressed in the EIS.

DOE produced the FutureGen 2.0 Draft EIS in April 2013 and published a Notice of Availability (NOA) in the Federal Register on May 3, 2013 (78 FR 26004). On the same date, the U.S.

Environmental Protection Agency (USEPA) published its NOA for the Draft EIS (78 FR 26027), which initiated the 45-day public comment period (from May 3 to June 17, 2013).

On May 21, 2013, DOE held a public hearing on the Draft EIS for the FutureGen 2.0 Project at Jacksonville High School, Jacksonville, Illinois. An informational session was held from 5:00 p.m. to 6:00 p.m., followed by the formal presentations and comment period from 6:00 p.m. to approximately 8:00 p.m.

DOE produced the FutureGen 2.0 Final EIS in November 2013 and EPA published a Notice of Availability in the Federal Register on November 1, 2013 (78 FR 65643). Subsequently, DOE produced and published the Record of Decision and Floodplain Statement of Findings for the FutureGen 2.0 in the Federal Register on January 22, 2014 (79 FR 3577).

A Appendix – MAJOR WORK PRODUCTS

MAJOR WORK PRODUCTS

A01 000 A.01 Comprehensive Project Management Report - Phase 2

A01 - PM Report 150915a.pdf

B01 000 B.01 Final Scientific/Technical Report

Master B 01 Final Scientific_Technical Report 042516.pdf

B01 A01 App A - AG 69kV & 138kV Electrical Reroute Drawings

Electrical Reroute Drawings.pdf

B01 A02 App A - Air Liquide Construction Schedule

27001 FutureGen Schedule Disc Data Date 2015.02.01.pdf

B01 A03 App A - Air Liquide Construction Strategy

ASU &CPU Construction_Execution_Plan for FutureGen Rev B .pdf

B01 A05 App A - Construction Labor Agreements

FutureGen NMAPC.pdf

FutureGen proj descpt 5-26-15.docx

B01 A07 App A - Division of Responsibility

Phase 2 DOR (Rev 7).xls

B01 A08 App A - Engineering Procurement and Construction Schedules

Closeout Summary Schedule.pdf

FG_Full Sched_Closeout.pdf

FG_Full Schedule.zip

FutureGen Schedule_July 2014.xer

Schedule Basis_Closeout.docx

Schedule Basis_Closeout-MHW Comments.docx

B01 A09 App A - Environmental Permits, Applications & Activities

2014 FG Annual Waste Report Signed final.pdf

Alliance FG2 Air Permit Application to Agency - Final Complete June 2013.pdf

Ameren FG2 Air Permit Application to Agency - Final Complete June 2013.pdf

ameren meredosia Stormwater NOI submittal 2014jan17.pdf

FAA Determination of No Hazard Letter.pdf

FG2 completed swppp owner certification page 2014feb21.pdf

FG2 General Stormwater Construction Permit issued 2014feb18.pdf

FG2 Stormwater SWPPP-cgp2012_final.pdf

Final Construction Permit 12020013 (MEC).pdf

ILEPAEmergEngineGenerator12 5 14 modified final.pdf

issued ww construction permit 2014jan23 - fg2.pdf

Meredosia - Permitting Action Plan 1201714.xlsx

NPDES permit modification submittal (wastewater) 2013june20 - fg2.pdf

NWP33 Application Final-signed.pdf

US EPA and IL Inventory ID Application Form Submittal 07232014.pdf

	US EPA and IL Inventory ID Form Submittal 07232014.pdf
	Wastewater Construction Permit Application-Phase 2.pdf
B01 A10 App A - Equipment Assessment Reports	
	HP-IP Rotor Bore Report (by Toshiba).pdf
	HP-IP Rotor Inspection and Condition Assessment (by Cotter).pdf
	HP-IP Rotor Thermal Fatigue Life Assess (by URS).pdf
	SPXHT Condenser Report.pdf
	SPXHT FWH Report.pdf
B01 A13 App A - NEPA Documentation	
	EIS-0460_FutureGen2.0_FEIS_Volume_II_Part_2.pdf
	EIS-0460D_FutureGen2.0_DEIS_Summary.pdf
	EIS-0460D_FutureGen2.0_DEIS_Volume_I.pdf
	EIS-0460D_FutureGen2.0_DEIS_Volume_II.pdf
B01 A14 App A - Plant Emissions Estimates	
	Pages from Ameren FG2 Air Permit Application to Agency - Final Complete June 2013.pdf
B01 A15 App A - Project Management Plan	
	7a2 Risk and Opportunity Mgmt Procedure Final 5 23 12.pdf
	B&W Org Chart Nov 2013.pdf
	FG 2_Roles and Resp_BW__Rev _11-21-2013_.pdf
	FG2.0 Roles and Responsibilities Rev 1.doc
	PMP 11-27-13 R1.docx
B01 A16 App A - Process Definition Rating Index	
	Oxy-Combustion Project PDRI Scorecard.pdf
B01 A17 App B - ASU - Cost Basis	
	FutureGen_Cost_Basis_for_Review-_RLA2[1].pdf
B01 B02 App B - ASU - ControlSystem Architecture	
	1.27001-60-01-IE-000090-D.pdf
	1.27001-60-01-PR-013903.pdf
B01 B17 App B - ASU - Final Project Geotechnical Investigation Analysis and Report	
	41-1-37374-001.pdf
B01 B18 App B - CPU - Cost Basis	
	FutureGen_Cost_Basis_for_Review-_RLA2[1].pdf
B01 B25 App B - CPU - Control System Architecture	
	1.27001-62-01-IE-000090-D_A.pdf
B01 B33 App B - CPU - Final Project Geotechnical Investigation Analysis and Report	
	41-1-37374-001.pdf
B01 B41 App B - GQCS - Piping Specialty Items List	
	DV03510-0.pdf
B01 B42 App B - GQCS - Piping Line List	

	DT91010-1.pdf
B01 B43 App B - GQCS - Valve Lists	
	DU07862-2.pdf
B01 B44 App B - GQCS - Mechanical Equipment List	
	B0277022-1.pdf
B01 B45 App B - GQCS - Mechanical System Descriptions	
	GQCS Mechanical System Description.docx
B01 B46 App B - GQCS - Air Utility list	
	DT88868-0.pdf
B01 B47 App B - GQCS - Instrument Lists	
	DT91468-2.pdf
B01 B48 App B - GQCS - Electrical Load List	
	DT90993-2.pdf
B01 B50 App B - GQCS - General Arrangement Drawings	
	FG GA -1 Combined (1).pdf
B01 B54 App B - Boiler - Valve Lists	
	FG2 BOILER VALVE LIST REV A.pdf
B01 B55 App B - Boiler - Mechanical System Descriptions	
	Boiler System Description.docx
B01 B56 App B - Boiler - Mechanical Equipment List	
	FG2 BOILER EQUIP LIST Rev1.pdf
B01 B57 App B - Boiler - Air Utility list	
	DV03876-0.pdf
B01 B58 App B - Boiler - Instrument Lists	
	FG2 BOILER INSTR LIST Rev2.pdf
B01 B59 App B - Boiler - Control System Architecture	
	FutureGen 2 Control System Architecture.pdf
B01 B60 App B - Boiler - Electrical Load List	
	FG2 BOILER LOAD LIST Rev2.pdf
B01 B61 App B - Boiler - Arrangement Drawings	
	Boiler General Arrangement Drawings.pdf
B01 B62 App B - BOP - Cost Basis	
	FG2 BWM Basis of Cost Estimate.pdf
B01 B64 App B - BOP - P&ID's	
	72055 LEGACY PLANT INSTRUMENT LIST-RETAIN.pdf
	BOP P&IDs.pdf
B01 B65 App B - BOP - Piping Specialty Items List	
	72055 Piping Specialty Items Lists.pdf
B01 B66 App B - BOP - Valve Lists	

72055 Control and Actuated Valve List.pdf

72055 Manual Valve List.pdf

B01 B67 App B - BOP - Piping Line List

72055 Piping Line List.pdf

B01 B68 App B - BOP - Mechanical System Descriptions

BOP - System Descriptions.pdf

B01 B69 App B - BOP - Mechanical Equipment List

72055 BOP Equipment List.pdf

B01 B70 App B - BOP - Equipment drawings

Air Compressors Drawings.zip

Boiler Island Elevator Drawing.zip

Chemical Feed Systems Drawings.zip

Chimney Drawings.zip

Circulating Water Pumps Drawings.zip

Coal Handling Drawings.zip

Coal Silo Flow Study Drawings.zip

Compressed Air Dryer Drawings.zip

Condenser Assessment Drawings.zip

Construction Power Switchgear Drawings.zip

Construction Power Transformer Drawing.zip

Cooling Towers Drawings.zip

CPU Condensate Neutralization System Drawings.zip

Feedwater Heater 4-5 Drawings.zip

Field Erected Tanks Drawings.zip

Pre-Engineered Buildings Drawings.zip

Raw Water Treatment Drawings.zip

Ultrafiltration and RO Systems Drawings.zip

Waste Water Treatment Drawings.zip

B01 B71 App B - BOP - Instrument Lists

72055 BOP INSTRUMENT LIST-NEW INSTRUMENTS.pdf

72055 LEGACY PLANT INSTRUMENT LIST-RETAIN (1).pdf

B01 B73 App B - BOP - Electrical Load List

72055-BOP Equipment List.pdf

B01 B74 App B - BOP - Electrical One-Line Diagrams

72055EE4001 sh1.pdf

72055EE4001 sh2.pdf

72055EE4009.pdf

C-4344.pdf

B01 B75 App B - BOP - Area Classification Drawings

72055EP4001.pdf

B01 B76 App B - BOP - Site Grading Plans	
	Site Preparation Drawings.pdf
B01 B77 App B - BOP - Site Clearing and Grubbing Plans	
	Mass Grading Drawing.pdf
B01 B78 App B - BOP - Final Project Survey (aboveground and Underground)	
	Site Topo Survey Files.zip
	UNDERGROUND SURVEY FILES.ZIP
B01 B79 App B - BOP - Final Project Geotechnical Investigation Analysis and Report	
	SUBSURFACE INFORMATION 72055.pdf
B01 B80 App B - BOP - Demolition Drawings	
	Demolition Cable Schedule.pdf
	Demolition Drawings.pdf
	Electrical Demolition Drawings 1.pdf
	Electrical Demolition Drawings 2.pdf
B01 B81 App B - BOP - Civil Laydown Drawings	
	Civil Laydown Area Drawings.pdf
B01 B82 App B - BOP - Stormwater Plans	
	Stormwater Drawings.pdf
B01 B83 App B - BOP - Arrangement Drawings	
	Arrangement Drawings (1).pdf
B01 B86 App B - BOP - Process Drain System Plans	
	72055MA004.pdf
B01 B87 App B - BOP - Site General Arrangement Drawings	
	Arrangement Drawings.pdf
B01 B88 App B - BOP -Legacy Plant Laser Image	
	A_Server_Database.zipZIP
	B_Model_Report.zip
	C_ZFC.zip
	D_DXF_Files.zip
	E_Survey.zip
B01 B89 App B - BOP -Legacy Plant Laser Image	
	Phase III FutureGen_CPU _PPP_Champigny_04-30-14 VF.pdf
B02 000 B.02 Lessons Learned - Technology Integration* Value Improvements and Program Management	
	B02 Lessons Learned 150911.pdf
B04 000 B.04 Power Plant, Pipeline, and Injection Site Interfaces	
	B.04 Power Plant, Pipeline, and Injection Site Interfaces.pdf
B06 000 B.06 Conference Papers and Proceedings	
	AL 4a_5_OCC3 Oxy advantages projects Tranier Session4a 120913 PPT.pdf
	AL 4a_6_Future oxycombustion systems - Air Liquide - Future Development of CPU.pdf

	AL 4b_5_2013-07-22_AL Zero emission plant PPT.pdf
	AL Paper Future Oxy combustion systems.pdf
	AL Paper Session 4A.pdf
	AL S2B-02 - Terrien (Air Liquide) PPT.pdf
	AL Scale up readiness- Air Liquide Paper and presentation.pdf
	BW BR-1850.pdf
	BW BR-1853.pdf
	BW BR-1870.pdf
	BW BR-1894.pdf
	BW OCC3 2013- DKM -Presentation.pdf
	BW Oxycoal 58 - CW12.pdf
	BW Oxyfuel 42 CW13 -DKM.pdf
	FG FutureGen 2 0_US China Clean Coal Forum_041813_v2 (3)-MHW.pdf
	FG FutureGen_Australian CCS Conference 2012.pdf
	FG FutureGen_Australian CCS Conference 2014.pdf
	FG FutureGen_IEA International Oxy-Combustion Conference #3 2013.pdf
	FG FutureGen_U.S. CCUS Conference 2012.pdf
	FG Williford - PCC - Oct-2014-for DOE Review CP-FINAL-Rev1.pdf
C01 000 C.01 SF425 Form	
	SF 425 DE-FE0005054 09142015 SIGNED.pdf
D01 000 D.01 Final Invention and Patent Report	
	27001 FutureGen PatentDoc 2015.07.08.pdf
	bw patent cert 09-30-2015.pdf

B Appendix – ACRONYMS AND ABBREVIATIONS

ACRONYMS AND ABBREVIATIONS

AC	Alternating Current
ACI	American Concrete Institute
ADC	Area Disposal Company
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	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	The Babcock & Wilcox Company
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
CB&I	Chicago Bridge and Iron
CCS	Carbon Capture and Storage
CCW	Closed Cooling Water
CDS	Circulating Dry Scrubber
CEDF	Clean Environment Development Facility
CEMS	Continuous Emissions Monitoring System
CFB	Circulating Fluidized Bed
CHS	Coal Handling System
CII	Construction Industry Institute
Cl	Chlorine or Chloride

CM	Construction Manager
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Chemical Oxygen Demand or Commercial Operation Date
COE	Cost of Electricity
ComEd	Commonwealth Edison
CPR	Coal Pile Runoff
CPU	CO_2 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
DPS	Delta Power Services
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
ESP	Electrostatic Precipitator
FAA	Federal Aviation Administration
FD	Forced Draft
FEED	Front End Engineering and Design
FEGT	Furnace Exit Gas Temperature
FERC	Federal Energy Regulatory Commission
FeS	Iron Sulfide
FGC	Flue Gas Concentration
FR	Federal Register
FW	Feedwater
Alliance	FutureGen Industrial Alliance, Inc.
FGD	Flue Gas Desulfurization
FRP	Fiberglass Reinforced Plastic
GOX	Gaseous Oxygen
GPS	Global Positioning System
GQCS	Gas Quality Control System
GSC	Gland Steam Condenser
GSU	Generator Step-Up
GWR	Guided Wave Radar
H_2	Hydrogen

H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HART	Highway Addressable Remote Transducer
HAZOP	Hazards and Operability
HCl	Hydrochloric Acid
HF	Hydrofluoric Acid
Hg	Mercury
HGI	Hardgrove Grindability Index
HHV	Higher Heating Value
HMI	Human-Machine Interface
HP	High Pressure or horsepower
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
ICC	Illinois Commerce Commission
ICEA	Illinois Competitive Energy Association
IDLH	Immediately Dangerous to Life and Health
IEPA	Illinois Environmental Protection Agency
IGCC	Integrated Gasification Combined Cycle
IGV	Inlet Guide Vanes
IIEA	Illinois Industrial Energy Consumers
IMS	Integrated Master Schedule
IP	Intermediate Pressure
IPS	Integrated Project Schedule
IPSOR	Interface Process Safety and Operability Review
JT	Joule-Thomson
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
MCB	Main Control Board
MCC	Motor Control Center
MCR	Maximum Continuous Rating
MCT	Main Cooling Tower
ME	Mist Eliminator
MFT	Master Fuel Trip
MGD	Million Gallons per Day
MISO	Midwest Independent System Operator

MMT	Million Metric Tons
MP	Medium Pressure
MTO	Material Take Off
N_2	Nitrogen
NAAQS	National Ambient Air Quality Standards
NDE	Non-Destructive Examination
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Association
NOA	Notice of Availability
NOI	Notice of Intent
NOx	Nitrogen Oxides
NPSH	Net Positive Suction Head
NSR	New Source Review
O_2	Oxygen
O&M	Operation and Maintenance
OD	Outside Diameter
OEM	Original Equipment Manufacturer
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
PAC	Powdered Activated Carbon
Pb	Lead
PC	Pulverized Coal
PCM	Power Control Module
PCS	Plant Control System
PDRI	Project Definition Rating Index
PFD	Process Flow Diagram
PHE	Potomac-Hudson Engineering, Inc.
PJFF	Pulse Jet Fabric Filter
PLA	Project Labor Agreement
PLC	Primary Logic Controller
PM	Project Manager
PPA	Power Purchase Agreement
PM	Particulate Matter
PR	Primary Recycle
PRB	Powder River Basin sub-bituminous coal
PSD	Prevention of Significant Deterioration
PSH	Primary Superheater
QA/QC	Quality Assurance / Quality Control
RAM	Reliability, Availability, and Maintainability

RH	Reheat
RO	Reverse Osmosis
ROW	Right of Way
RTD	Resistance Temperature Detector
SCAH	Steam Coil Air Heater
SDA	Spray Dryer Absorber
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
SPCC	Spill Prevention Control and Countermeasures Plan
SR	Secondary Recycle
SSH	Secondary Superheater
ST	Steam Turbine
STG	Steam Turbine Generator
T&D	Transmission and Distribution
TDH	Total Developed Head
TDS	Total Dissolved Solids
TOC	Total Organic Carbon
TOD	Total Oxidant Demand
TPD	Tons per Day
TSA	Temperature Swing Adsorption
TS&M	Transport Store and Monitor
TSO	Tight Shut-Off
TSS	Total Suspended Solids
UF	Ultrafiltration
UPS	Uninterruptible Power Supply
URS	URS Corporation
VFD	Variable Frequency Drive
VOM	Volatile Organic Matter
VSD	Variable Speed Drive
VWO-OP	Valves Wide Open, 5% Overpressure (STG Throttle condition)
WACC	Weighted Average Cost of Capital
WBS	Work Breakdown Structure
WT	Water Treatment
WWTS	Wastewater Treatment System