**CO-PRODUCTION OF HYDROGEN AND ELECTRICITY
USING
PRESSURIZED CIRCULATING FLUIDIZED BED
GASIFICATION TECHNOLOGY**

Final Report By:

**Zhen Fan
Archie Robertson**

Issued August 2006

**Performed Under
U.S. Department of Energy
Cooperative Agreement No: DE-FC26-00NT40972**

**DEVELOPMENT OF PRESSURIZED CIRCULATING FLUIDIZED BED
PARTIAL GASIFICATION MODULE**

**Foster Wheeler Development Corporation
12 Peach Tree Hill Road
Livingston, New Jersey 07039**

Disclaimer

"This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe upon privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

Acknowledgement

This work was performed by Foster Wheeler Development Corporation under U.S. Department of Energy (DOE) Cooperative Agreement No. DE-FC26-00NT40972. Arun C. Bose was the DOE Contracting Officer's Technical Representative that guided the conduct of the work.

The Parsons Infrastructure and Technology Group assisted Foster Wheeler by providing engineering and economic analyses of the cases studied herein. Parsons provided this assistance via National Energy Technology Laboratory Contract No DE-AM26-04NT41817 (Subtask No 41817.305.61.11.051).

The Parsons' personnel and their subcontractors that participated in the study were:

Harvey Goldstein, Project Manager, Parsons Infrastructure and Technology Group
Jay White, Performance Engineer, WorleyParsons
William McMahon Jr., Estimator and Economic Analyst, Econ Opportunities, Inc.

Abstract

Foster Wheeler has completed work under a U.S. Department of Energy cooperative agreement to develop a gasification equipment module that can serve as a building block for a variety of advanced, coal-fueled plants. When linked with other equipment blocks also under development, studies have shown that Foster Wheeler's gasification module can enable an electric generating plant to operate with an efficiency exceeding 60 percent (coal higher heating value basis) while producing near zero emissions of traditional stack gas pollutants. The heart of the equipment module is a pressurized circulating fluidized bed (PCFB) that is used to gasify the coal; it can operate with either air or oxygen and produces a coal-derived syngas without the formation of corrosive slag or sticky ash that can reduce plant availabilities.

Rather than fuel a gas turbine for combined cycle power generation, the syngas can alternatively be processed to produce clean fuels and or chemicals. As a result, the study described herein was conducted to determine the performance and economics of using the syngas to produce hydrogen for sale to a nearby refinery in a hydrogen-electricity co-production plant setting. The plant is fueled with Pittsburgh No. 8 coal, produces 99.95 percent pure hydrogen at a rate of 260 tons per day and generates 255 MWe of power for sale. Based on an electricity sell price of \$45/MWhr, the hydrogen has a 10-year levelized production cost of \$6.75 per million Btu; this price is competitive with hydrogen produced by steam methane reforming at a natural gas price of \$4/MMBtu. Hence, coal-fueled, PCFB gasifier-based plants appear to be a viable means for either high efficiency power generation or co-production of hydrogen and electricity.

This report describes the PCFB gasifier-based plant, presents its performance and economics, and compares it to other coal-based and natural gas based hydrogen production technologies.

Table of Contents

<u>Section</u>	<u>Page</u>
1.0 Introduction	1
2.0 Executive Summary	4
3.0 Experimental / Plant Design and Economic Bases	7
3.1 General Requirements	7
3.2 Plant Site Conditions	8
3.3 Feed Stocks	8
3.4 Economic Factors	9
3.5 Cost Estimating Methodology	11
3.5.1 General	11
3.5.2 Economic Factors	13
3.5.3 Evaluation Approach	13
3.5.4 Capital Costs	14
3.5.5 Bare Erected Costs	14
3.5.6 Total Plant Cost	14
3.5.7 Total Plant Investment	15
3.5.8 Total Capital Requirement	17
3.5.9 Capital Cost Estimate Exclusions	17
3.5.10 Operating and Maintenance Costs	18
3.5.11 Consumable Operating Costs	19
3.5.12 By-Product Credits	20
3.5.13 Fuel Cost	20
3.5.14 Total Production Cost	20
3.5.15 Carrying Charges	20
3.5.16 Cost of Hydrogen	20
4.0 Entrained Flow Gasifier Based Co-Production Plant	22
4.1 Plant Overview, Performance, and Emissions	22
4.2 Process and System Description	29
4.3 List of Plant Major Equipment	34
4.4 Plant Costs and Economic Analysis	34
5.0 PCFB Gasifier Based Co-Production Plant	41
5.1 Plant Overview, Performance, and Emissions	41
5.2 Process and System Description	48
5.3 List of Plant Major Equipment	59
5.4 Plant Costs and Economic Analysis	59
6.0 Hydrogen Production by Steam Methane Reforming (SMR)	64
7.0 Results and Discussion / Plant Comparisons	66

7.1	Redundancy and Plant Availability	66
7.2	Overall Plant Arrangement	66
7.3	Plant Performance	70
7.4	Plant Emissions	73
7.5	Plant Costs and Economics	74
7.6	CO2 Sequestering	77
8.0	Conclusions	78
9.0	References	79
10.0	Bibliography	80
11.0	List of Acronyms and Abbreviation	81
Appendix A	E-Gas Entrained Flow Gasifier Co-Production Plant with Spare Gasifier	A1
A1.	List of Major E-Gas Co-Production Plant Equipment by Account	A2
A2.	Total Plant Cost Estimate.....	A12
Appendix B	E-Gas Entrained Flow Gasifier Co-Production Plant without Spare Gasifier.....	B1
B1.	Total Plant Cost Estimate.....	B2
Appendix C	Foster Wheeler PCFB Gasifier Co-Production Plant.....	C1
C1.	List of Major PCFB Co-Production Plant Equipment by Account	C2
C2.	Total Plant Cost Estimate.....	C11

List of Graphical Materials

<u>Figures</u>		<u>Page</u>
1.1	PCFB Gasification Module for Advanced Energy Plants.....	2
3.5.4.1	Components of Capital Costs.....	16
4.1.1	Entrained Flow Plant Process Block Diagram.....	23
4.1.2	Entrained Flow Plant Process Stream Locations	25
4.1.3	Entrained Flow Plant Process Stream Operating Conditions	26
5.1.1	PCFB Gasifier Plant Process Block Diagram.....	42
5.1.2	PCFB Gasifier Plant Flow Stream Locations	44
5.1.3	PCFB Gasifier Plant Flow Stream Operating Conditions	45
5.2.1	PCFB Gasifier Arrangement	52
5.2.2	CFB Boiler Side View	55
5.2.3	CFB Boiler Isometric View	56
5.2.4	Spray Dryer Scrubber, Baghouse, ID Fan, and Stack Side View	57
5.4.1	Effect of Electricity Sell Price on PCFB Plant H ₂ Sell Price.....	64
6.1	Natural Gas Steam Reforming Process Block Diagram	65
6.2	Cost of Hydrogen Produced from Steam Methane Reforming.....	65
7.2.1	Two Train IGCC Combined Cycle Plant Arrangement.....	69

Tables

2.1	Summary Comparison of Co-Production Plant Performance & Economics	7
3.3.1	Coal Analysis	9
3.3.2	Limestone Composition.....	9
3.4.1	Cost and Escalation.....	10
3.4.2	Estimating Criteria and Financial Assumptions	11
3.5.10.1	Operating Labor for Co-Production Plants	19
3.5.11.1	Consumable Unit Costs.....	20
4.1.1	E-Gas Entrained Flow Plant Performance Data.....	27
4.1.2	E-Gas Entrained Flow Plant Parasitic Power.....	28
4.1.3	E-Gas Entrained Flow Plant Emissions	29
4.4.1	E-Gas Plant TPC in Thousands of Year 2005 Dollars (3 & 2 Train Plants)	35
4.4.2	E-Gas Plant Operating and Consumable Requirements	36
4.4.3	E-Gas Plant Operating and Consumables Costs	37
4.4.4	E-Gas Plant Hydrogen Production Cost (3 Train Plant).....	38
4.4.5	E-Gas Plant Hydrogen Production Cost (2 Train Plant).....	39
4.4.6	E-Gas Plant Economic Summary (3 & 2 Train Plants)	40
5.1.1	PCFB Gasifier Plant Performance Summary.....	46
5.1.2	PCFB Gasifier Plant Parasitic Power Losses	47
5.1.3	PCFB Gasifier Plant Emissions	48
5.2.1	PCFB Gasifier Syngas Compositions	53
5.4.1	PCFB Plant TPC in Thousands of Year 2005 Dollars	60
5.4.2	PCFB Plant Capital and Operating Requirements	61
5.4.3	PCFB Plant Operating and Consumables Costs	62

5.4.4	PCFB Plant Hydrogen Production Cost.....	63
7.2.1	Comparison of Co-Production Plant Foot Prints	68
7.3.1	Comparison of Co-Production Plant Overall Performance	71
7.3.2	Comparison of Co-Production Plant Parasitic Power.....	72
7.3.3	Comparison of Co-Production Plant Energy Losses	73
7.4.1	Comparison of Co-Production Plant Emissions	74
7.5.1	Comparison of Plant Capital Investments and Economics	76
7.5.2	Comparison of Total Plant Costs by Accounts	77

1.0 Introduction

One of the objectives of the Energy R&D Program of the US Department of Energy (DOE) is to develop the technologies that will be required by the advanced, coal fueled, energy plants of the 21st century. Rather than develop a specific plant configuration, the program focuses on developing “enabling” technologies that can serve as building blocks through which a variety of advanced power generation and or clean fuels/chemical production plants can be built. When utilized for electrical power generation, those plants are to operate with efficiencies greater than 60 percent (coal higher heating value basis) while producing near zero emissions of traditional stack gas pollutants.

Foster Wheeler Development Corporation (FW) proposed the development of a gasification equipment module (see Figure 1.1) that can serve as a building block for a variety of advanced, coal-fueled, energy plants. Analyses conducted by FW and Nexant [1-1] and an independent analysis conducted by [1-2] both indicate the gasification module, together with other building blocks, can yield a power generating plant with an efficiency that exceeds the 60 percent goal. The heart of the gasification module is a pressurized circulating fluidized bed (PCFB) gasifier that does not attempt to consume the coal in a single step. To convert all the coal to syngas in a single step requires extremely high temperatures (~2500 to 2800°F) that melt and vaporize the coal and drive coal ash contaminants into the syngas. These contaminants can foul and or corrode the gasifier and downstream equipment and the syngas must be cooled to near room temperature to enable a series of chemical processes to clean the syngas. FW’s process operates at much lower temperatures that extend component life, minimize the release of ash contaminants, and allow the use of sulfur and alkali capturing adsorbents. As a result, sticky ash fouling conditions, molten slag corrosion conditions, and the need for room temperature chemical cleanup systems, all of which are typical of high temperature gasification, are eliminated.

By performing the gasification in a circulating fluidized bed (CFB), which consists of a riser section, a recycle cyclone, and a dipleg, coal particles are continuously circulated through the gasification zone; despite the reduced temperature, each succeeding pass increases the amount of coal carbon that is converted into syngas. Eventually the circulating coal particles reach a density and size that allow their escape from the unit; exiting as syngas entrained particulate matter, the escaping char particles are collected by a down stream barrier filter. As a result, the PCFB gasifier produces a coal char residue along with syngas. Depending upon the coal and operating conditions, carbon conversions can range from mid eighties for less reactive Eastern bituminous coals to mid nineties for more reactive Western subbituminous coals. The circulating bed also provides high fuel flexibility, facilitates scale up to large size plants, and can operate with oxygen to facilitate sequestration of stack gas carbon dioxide gases for a reduction in greenhouse gas emissions.

The char generated by the PCFB gasifier is not a waste stream, instead, it is an extremely essential ingredient in maximizing the plant efficiency. After collection, the char is transferred to a combustor where it becomes a source of high level heat for the plant’s steam cycle. In a typical integrated gasification combined cycle (IGCC) plant the steam turbine operating temperatures (superheat and reheat) are limited by the energy content of the gas turbine exhaust. With the char heat release available to supplement this, steam turbine pressures and temperatures are no longer limited to 2400 psig and 1000°F but instead can rise to ultra supercritical conditions and operate

Figure 1.1 PCFB Gasification Module for Advanced Energy Plants

with a highly efficient regenerative feed water heating system. By having a char stream to combust, the steam cycle efficiency and the overall plant efficiency can be increased.

The gasification equipment module consists of the PCFB gasifier and a downstream, particulate removing barrier filter; if desired, a syngas cooler can be provided upstream of the filter to control its operating temperature. Coal, air, and steam are fed to the bottom of the PCFB riser and establish a relatively dense bed of coal/char in the bottom section. As these constituents react, a hot syngas is produced which conveys the solids residue vertically up through the reactor and into the recycle cyclone. Solids elutriated from the dense bed and contained in the syngas are collected in the cyclone and drain via a dipleg back to the dense bed at the bottom of the PCFB reactor. This recycle loop of hot solids acts as a thermal flywheel and promotes efficient solid-gas chemical reaction. As the solids continuously circulate through the gasifier, they reach a density and or size that eventually allow their escape from the recycle cyclone to the downstream filter. The filter collects this material for depressuring and transfer to the char combustor. To prevent any over size material from accumulating within the gasifier, solids are intermittently drained from the bottom of the bed, depressured, and also transferred to the char combustor.

Left untreated the particle bearing syngas will contain contaminants such as alkali vapors, hydrogen sulfide, ammonia, etc. at levels dependent on gasifier operating conditions and fuels. The downstream users of the syngas will dictate a tolerance level for each of these gas constituents. If hydrogen sulfide cannot be tolerated, lime based sorbents can be fed to the PCFB gasifier along with the coal to capture the sulfur as calcium sulfide. Depending upon sorbent feed rates and gas residence times, the hydrogen sulfide can be reduced to near equilibrium levels, which for high sulfur fuels (>3 percent sulfur), amounts to 95 to 98 percent sulfur capture. In addition to providing sulfur capture, lime based sorbents will catalytically enhance the cracking of any tar/oil vapors that may be present in the syngas.

If alkali vapors levels must be reduced, the syngas can be cooled to a level that condenses the alkali vapors on the particulate being removed by the barrier filter. Although this is a simple solution to an alkali problem, syngas cooling typically lowers the plant efficiency. When

efficiency is to be maximized, the clean up can be done hot/without syngas cooling. Alkali levels can be brought to gas turbine acceptable levels by injecting finely ground getter material such as emathlite or bauxite into the syngas between the recycle cyclone and filter. The fine particulate that escapes the recycle cyclone together with the injected alkali getter material are carried into the barrier filter by the syngas. As the syngas flows through the porous filter elements, the particulate collect on the outside of the elements and forms a permeable dust cake that the syngas must pass through. The getter absorbs the alkali vapors as the syngas flows to the filter and passes through the filter dust cake. As the dust cake thickness increases, the filter pressure drop increases. Upon reaching a predetermined pressure drop, the dust cake is blown off the element by a back pulse of a clean, high-pressure gas such as nitrogen or recycled syngas injected into the clean side of the element. The dislodged dust cake falls to the bottom of the filter vessel and drains from the unit. If even higher sulfur capture efficiencies are desired, a second more reactive sorbent can be injected into the syngas for enhanced filter cake sulfur capture. Although the barrier filter is provided to reduce syngas particulate loadings to less than 1 ppm, it can also serve as a reactor in that its filter cake can be used for alkali vapor removal and sulfur capture. If costs are to be minimized, the filter can be preceded by a pre-cleaner cyclone that reduces the particulate loading entering the filter and allows a smaller unit to be utilized.

To support the development of PCFB gasification, pilot plant tests were conducted by FW at its John Blizard Research Center in Livingston, NJ, in the September 2001 through January 2002 time period; the tests determined gasification module performance characteristics when operating with a variety of fuels, e.g., one subbituminous coal, four bituminous coals, petroleum coke, and saw dust. The module consisted of a 7 inch ID PCFB gasifier together with a recycle cyclone, a syngas cooler, a pre-cleaner cyclone, and a barrier filter. The module operated successfully with all the fuels and a total of 22 test points were completed. The syngas and char yields, heating values, compositions, and carbon conversions observed in the pilot plant test program were found to meet and or exceed levels required by FW's Vision 21 electric power generating plant.

Rather than fuel power generation, the syngas could alternatively be processed to produce clean fuels and or chemicals. To identify the merits of such an arrangement, the performance and economics of using the gasification module/building block to simultaneously co-produce hydrogen and electricity has been studied in this report.

Working under DOE contracts, Parsons Infrastructure and Technology Group Inc. (Parsons) has conceptually designed and determined the performance and economics of several entrained flow type IGCC plants. These studies have included plants designed for electric power generation [1-3] as well as a plant designed primarily for the production of hydrogen [1-4]. To minimize the cost of the co-production plant study, it was decided to design the plant for the same hydrogen and electricity production rates of a co-production plant conceptually designed and cost estimated by Parson; this allowed reuse of much of the balance of plant design and costing work already performed by Parsons. To assure a consistent comparison of PCFB gasification versus entrained flow gasification technologies, Parsons was retained via a separate DOE contract to work with FW to determine and compare the performance and economics of both plants. The results of Parsons' efforts are presented in [1-5].

The plants, which have been conceptually designed to produce 261 tons of hydrogen per day and approximately 255 MWe of electricity, are described in detail in Sections 4 and 5; in Section 7 their performance and economics are compared to each other and to that of a natural gas steam reforming plant described in Section 6.

2.0 Executive Summary

FW has developed a coal gasification process that can serve as a building block for a variety of advanced energy plants. When utilized for electric power generation with other advanced components under development, those plants will operate with efficiencies greater than 60 percent (higher heating value basis) while producing near zero emissions of traditional stack gas pollutants. The heart of the equipment module is a pressurized circulating fluidized bed (PCFB) that is used to gasify the coal; it can operate with either air or oxygen and produces a coal-derived syngas without the formation of corrosive slag or sticky ash that can reduce plant availabilities.

Rather than fuel a gas turbine for combined cycle power generation, the syngas can alternatively be processed to produce clean fuels and or chemicals. As a result, the study described herein was conducted to determine the performance and economics of using the syngas to produce hydrogen for sale to a nearby refinery in a hydrogen-electricity co-production plant setting.

To minimize the cost of the co-production plant study, it was decided to design the PCFB based plant for the same hydrogen and electricity production rates of a co-production plant conceptually designed and cost estimated by the Parsons Infrastructure and Technology Group Inc. (Parsons); this allowed reuse of much of the balance of plant design and costing work already performed by Parsons. To assure a consistent comparison of PCFB gasification versus entrained flow gasification technologies, Parsons was retained, via a separate DOE contract, to work with FW to determine and compare the performance and economics of both plants.

The plants were conceptually designed to produce 261 tons of hydrogen per day and approximately 255 MWe of electricity. The plants were fueled with Pittsburgh No 8 coal and used pressure swing absorption (PSA) technology to produce 99.95 percent purity hydrogen. The hydrogen was produced for sale to a near by refinery at a pressure of approximately 355 psig, whereas, the electricity was sold to the grid.

The entrained flow gasifier plant uses two 50 percent capacity, oxygen blown, gasifier equipment trains to meet its syngas needs. The first operating train produces syngas for hydrogen production, whereas, the second train produces an equal amount of syngas for power generation. Although the trains operate in parallel at identical conditions, their gases are kept separate to simplify control and operating stability (assures an upset/problem in one leg of the plant will not disrupt the other). The operating reliabilities of the single train, coal fueled, IGCC demonstration plants that were built in the 1990s have been well below 90 percent. At the Year 2005 Gasification Technologies Conference two IGCC developers (ConocoPhillips, owner of the E-Gas Process, and GE Energy, owner of the ChevronTexaco Process) recommended that their two train IGCC plants be provided with a third or spare train of gasifier equipment to achieve 90 percent plant availability [2-1], [2-2]. Consistent with this, the E-Gas based co-production plant has been provided with a third/spare 50 percent train. The spare train will be brought on-line for either hydrogen or power production when one of the other two trains is shut-down for maintenance; to allow for future

technology improvements, however, plant economics are presented both with and without the spare train.

Each gasifier equipment train consists of a coal-water slurry tank, a slurry pump, a slurry heater, a two stage entrained flow gasifier as exemplified by the E-GasTM gasifier at the Clean Coal Technology Wabash River Repowering Project, a slag rejection system, a fire-tube boiler/syngas cooler, a cyclone, a candle filter, a water scrubber, and a fines return system. The syngas generated by the gasifier is cooled to 690°F by the fire-tube boiler to allow removal of gas entrained particulate by the cyclone and filter. After cooling, particulate removal, and water scrubbing, the syngas from the first train undergoes water gas shifting, acid gas removal, and pressure swing absorption (PSA) to produce 99.95 percent pure hydrogen at a rate of 261 tpd at 355 psig for sale to the nearby refinery. The ~20 psia low Btu purge gas/vent gas from the PSA is fired in a boiler to produce steam for the process and to drive a nominal 50 MWe steam turbine. The syngas from the second train undergoes carbonyl sulfide (COS) hydrolysis, acid gas removal, reheating, and humidification; this gas then fuels a combined cycle plant incorporating a 197 MWe General Electric 7FA gas turbine and a nominal 100 MWe steam turbine; the electric power from both trains is sold to the grid to provide a revenue stream that reduces the hydrogen sell price.

The PCFB co-production plant utilizes a single, oxygen blown PCFB gasifier together with a single, atmospheric pressure CFB boiler to meet the plant hydrogen and power generation needs. Since the PCFB gasifier operates at a relatively low temperature that is below the coal ash fusion temperature, its availability is expected to be typical of CFB boilers, e.g., (~95 percent per Section 7.1) and a spare train of gasifier equipment is not required. To assure a consistent comparison of the two plants, the PCFB gasifier operates with the same coal-water slurry and oxygen feeds as the entrained flow plant and its syngas is cooled by a fire-tube type boiler to 650°F to allow particulate removal by a cyclone and candle filter. Thereafter water gas shifting and PSA technology are used to produce 99.95 percent pure hydrogen at a rate of 261 tpd at 355 psig for sale to the refinery. The vent gas from the PSA and the char from the gasifier, the latter after depressuring, are fired along with crushed coal and limestone in the CFB boiler. The CFB boiler package, which includes a sulfur dioxide (SO₂) polishing scrubber, produces steam for process use and drives a nominal 308 MWe steam turbine. The steam turbine power is sold to the grid to provide a revenue stream that reduces the hydrogen sell price. In the event the gasification leg of the plant should be out of service, the CFB boiler can be operated totally on coal to maintain its full load revenue stream.

The economics of both plants have been analyzed using a consistent set of assumptions, i.e., Pittsburgh No. 8 coal price of \$1.61/MMBtu, an electricity sell price of \$45/MWhr, etc., and Table 2.1 summarizes the results of the study. The PCFB gasifier based plant operates with an effective thermal efficiency of 53.0 percent (coal higher heating value basis), a total plant cost in year 2005 dollars of \$625.4 million, and produces hydrogen at a 10 year levelized cost of \$6.75/MMBtu. The levelized cost accounts for all capital, consumables, fuel, operating and maintenance, and interest costs and includes a 12 percent return on equity. Compared with the entrained flow plant, the PFB gasifier plant efficiency is 5.4 percentage points higher, its total plant costs 7.8 percent lower, and its levelized hydrogen cost 4.4 percent lower.

In the PCFB gasifier based plant, the stack gases originate from the CFB boiler system and the latter becomes the emission control system of the plant. The emissions shown in Table 2.1 for the PCFB gasifier based plant are based on pound per million Btu emission rates measured in the Jacksonville Electric Authority 300 MWe CFB Boiler Demonstration Project with its CFB boiler operating with Pittsburgh No 8 coal, the fuel of this study. The entrained flow gasifier plant emissions are also shown in Table 2.1; they are based on rates observed at the Wabash IGCC Demonstration Plant but modified to incorporate recycle of Claus Plant tail gas back to the gasifier and gas turbine nitrogen injection. These features have been incorporated to improve the plant's sulfur capture efficiency and reduce its gas turbine oxides of nitrogen (NO_x) emissions. As shown in Table 2.1, the NO_x and particulate emissions of the two plants are comparable with the most significant differences occurring in SO₂ and carbon monoxide (CO) emissions. Recycling the Claus Plant tail gas back to the gasifier is expected to increase the plant sulfur capture efficiency from ~98 to 99.5 percent. With the CFB boiler system operating at the Jacksonville 98.5 percent sulfur capture efficiency, the entrained flow gasifier plant (SO₂) emission is projected to be about 1/3 of that of the PCFB gasifier plant. In contrast, the CO emission rate of the PCFB gasifier based plant is about 1/5 of that of the entrained flow gasifier plant.

Hydrogen is typically produced by steam methane reforming and its production costs are highly sensitive to the price of its natural gas feedstock. At a levelized cost of \$6.75/MMBtu, hydrogen produced by the PCFG gasifier plant will be competitive with steam methane produced hydrogen at a natural gas price of approximately \$4/MMBtu. With natural gas spot prices well above these values, the future prospects of PCFB gasifier produced hydrogen appear favorable.

The efficiencies and hydrogen costs of the above coal and natural gas based plants are exclusive of carbon dioxide (CO₂) removal for sequestration. All of these plants, however, can incorporate CO₂ removal and, hopefully, the effect of its capture on the PCFB gasifier based plant performance and economics will be the subject of a later study.

Previous studies [1-1] [1-2] have shown that PCFB gasifier based plants can meet the Vision 21 60 percent efficiency goal for advanced power generating plants. This study has shown that the PCFB gasifier based co-production plant can produce hydrogen at a cost competitive with that of steam methane reforming. The amount of syngas and char produced by the PCFB gasifier can be tailored to fit the production objectives of the overall plant, e.g., power generation and/or hydrogen production. Although not yet studied, it is believed it may also be a viable means for producing liquid fuels and chemicals from coal. Hence, the PCFB gasifier is a product-flexible, robust building block by which a wide variety of plants can be built – be they Vision 21 plants of the future or a high efficiency combined cycle/gas turbine-steam turbine plant of today

Table 2-1 Summary Comparison of Co-Production Plant Performance and Economics

Type of Gasifier	Entrained Flow	PCFB
Plant Effective Thermal Efficiency*, % (HHV)	47.6	53.0
H ₂ Production Rate, lb/hr	21,703	21,753
Net Power Output, MWe	251.9	255.5
Gross Power, MWe		
7 FA Gas Turbine	197.0	
Steam Turbine	149.0	307.7
Parasitic Power, MWe	94.1	52.2
Plant Sulfur Capture Efficiency, %	99.5	98.5
Stack Emissions, lb/hr		
SO ₂	107	289
NO _x	194	197
CO	297	45
Particulate	8	24
Total Plant Cost, millions of Year 2005 Dollars	678.5**	625.4
10 Year Levelized H ₂ Production Cost, \$/MMBtu	7.06	6.75

*Power at 3,413 Btu/hr/KWe and Hydrogen at 61,095 Btu/lb

**647.8 with spare gasification train eliminated

3.0 Experimental/Plant Design and Economic Bases

3.1 General Requirements

The PCFB gasifier based and the entrained flow gasifier based co-production plants were each designed to produce approximately 261 tpd (~94 MMSCF) of 99.95 percent purity hydrogen at 355 psig while simultaneously generating ~255 MWe of electric power. To assure a consistent comparison of the two technologies, both plant were designed to operate with:

- a.) Pittsburgh No 8 coal
- b.) coal-water slurry feed to gasifier(s)
- c.) oxygen blown gasifier(s)
- d.) 95 percent pure oxygen supplied by conventional cryogenic air separation units (ASU)s
- e.) syngas cooling to ~ 650F via fire-tube boiler(s)
- f.) syngas particulate removal at ~650F via a cyclone and candle filter
- g.) water gas shifting via sulfur tolerant catalysts for a ~91 percent overall CO conversion efficiency at a steam to CO molar ratio of 1.75

- h.) hydrogen separation via conventional PSA technology yielding 99.95 percent purity
- i.) steam condenser back pressure of 1.0 psia

3.2 Plant Site Conditions

The plant site is assumed to be in the Ohio River Valley of southwestern Pennsylvania/eastern Ohio with the following characteristics:

Location	Middle Town USA
Topography	Level
Elevation	500 feet (152.4 meters)
Seismic Zone	1
Air Temperature	59°F (15°C)
Relative Humidity	60 Percent
Transportation	Rail Access
Water	Municipal
Ash Disposal	Off Site

3.3 Feedstocks

The plants have been designed to operate with 2.9 percent sulfur Pittsburgh No 8 coal and, if desired, limestone. Analyses of these feedstocks are given in Tables 3.3.1 and 3.3.2.

Table 3.3.1 Coal Analysis

Type/Name	Bituminous/Pittsburgh No. 8
As Received HHV, Btu/lb	12,450
Proximate Analysis, wt %	
Moisture	6.00
Volatile Matter	35.91
Ash	9.94
Fixed Carbon	48.15
Ultimate Analysis, wt %	
Carbon	69.36
Hydrogen	5.18
Nitrogen	1.22
Sulfur	2.89
Ash	9.94
Oxygen	11.41

Table 3.3.2 Limestone Composition (wt %)

Calcium Carbonate	92.7
Magnesium Carbonate	3.7
Inerts	3.6

3.4 Economic Factors

The cost and economic assumptions used in this study are given in Tables 3.4.1.and 3.4.2.

Table 3.4.1 Cost and Escalation

Feed Costs	Year 2005	
Coal, \$/MMBtu	1.61	0.10% Inflation (2005-2025)
Limestone, \$/ton	18.00	2.50% Inflation (2005-2025)
Water, \$/MMgal/day	815.00	2.50% Inflation (2005-2025)
Water Treatment Chemicals, \$/lb	0.20	2.50% Inflation (2005-2025)
Liquid Effluent Chemicals, \$/lb	0.15	2.50% Inflation (2005-2025)
Amine Acid Gas Removal Solvent, \$/lb	1.09	2.50% Inflation (2005-2025)
Ammonia, \$/lb	0.22	2.50% Inflation (2005-2025)
Catalyst Costs		
Carbonyl Sulfide, \$/ft3	575.00	2.50% Inflation (2005-2025)
First High Temperature Shifter, \$/ft3	450.00	2.50% Inflation (2005-2025)
Second High Temperature Shifter, \$/ft3	450.00	2.50% Inflation (2005-2025)
Low Temperature Shifter, \$/ft3	450.00	2.50% Inflation (2005-2025)
Claus Furnace Reactor # 1, \$/ft3	325.00	2.50% Inflation (2005-2025)
Claus Furnace Reactor # 2, \$/ft3	325.00	2.50% Inflation (2005-2025)
Hydrogenation, \$/ft3	290.00	2.50% Inflation (2005-2025)
Waste Disposal Costs		
Ash/ Slag Disposal, \$/ton	12.00	2.50% Inflation (2005-2025)
By-Product Sell Price		
Sulfur, \$/ton	75.00	2.50% Inflation (2005-2025)
Electricity, \$/MWhr	45.00	2.50% Inflation (2005-2025)
Other Costs		
Plant Operating Labor, \$/hr	28.00	2.50% Inflation (2005-2025)
Plant Land, \$/acre	2500.00	2.50% Inflation (2005-2025)

Table 3.4.2 Estimating Criteria and Financial Assumptions

General Data

Levelized Capacity Factor:	90 %
Capital Cost Year Dollars:	2005 (January)
Time to Design and Construct Plant:	4 years
Plant Startup Date(year):	2009 (January)
Plant Land Area	100 acres

Financial Criteria

Project Book Life:	20 years
Book Salvage Value:	0.0 %
Project Tax Life:	20 years
Tax Depreciation Method:	Accel. Based of ACRS Class
Property Tax Rate:	1.0 % per year
Insurance Tax Rate:	1.0 % per year
Federal Income Tax Rate:	34.0 %
State Income Tax Rate:	6.0 %
Investment Tax Credit/% Eligible	0.0 %

Economic Basis: 10th Year Constant Dollars

	% of Total	Cost(%)
Capital Structure		
Common Equity	20	12.0
Tax Free Municipal Bond Debt	80	6.0

Weighted Cost of Capital, % :(after tax) 5.4

Escalation Rates	<u>2009 to 2029</u>	<u>2005 to 2009</u>
General	2.5 % per year	2.5 % per year
Coal Price	0.100 % per year	0.100 % per year

3.5 Cost Estimating Methodology

3.5.1 General

Working under DOE contracts, Parsons has prepared conceptual designs and determined the performance and economics of several different IGCC plants. Plants based on the E-GasTM gasification technology exemplified at the Clean Coal Technology Demonstration Plant located at Wabash [3-1] have been included in those studies. The E-Gas plants studied have incorporated two 50 percent capacity trains of gasification equipment that operate in parallel to produce syngas

for either power generating gas turbines [1-3] or for water gas shifting and pressure swing absorption (PSA) systems for hydrogen production [1-4].

In this study, plants incorporating E-Gas and PCFB gasification technologies are being evaluated/compared to determine their performance and economics for co-producing hydrogen and electricity. The first plant utilizes three 50 percent capacity E-Gas gasifiers. The first gasifier produces syngas for PSA based hydrogen production, the second gasifier produces syngas for gas turbine power generation, and the third gasifier is a spare that is brought on line when one of the other two gasifiers is shut down for repairs/maintenance. Although present experience indicates the spare gasifier is needed to achieve 90 percent plant availability, plant economics have been determined both with and without the spare to allow for future technology advances. Mass and energy balances were prepared by Parsons for the E-Gas based co-production plant and used to establish its equipment sizes and arrangements. Since the plant components were similar to those of the prior studies, Parsons used the prior study values to establish co-production plant equipment costs; adjustments were made, however, for differences in flow rates and the costs involved were escalated to year 2005 values using published engineering and construction indices. Since E-Gas technology has been successfully demonstrated at a ~250 MWe scale at Wabash, no process contingencies were applied to the E-Gas equipment trains.

The second co-production plant, which is based on FW's circulating fluidized bed technologies, also utilizes two trains of operating equipment. The first equipment train is similar to the E-Gas based plant in that it utilizes a coal-water slurry fed, oxygen blown gasifier to produce a coal-derived syngas for water gas shifting and PSA based hydrogen production. Unlike the E-Gas based plant, however, the FW plant utilizes a single PCFB to gasify its coal and the second train of equipment utilizes a CFB boiler to combust a mixture of coal, gasifier char, and PSA vent gas to produce steam for process use and electric power generation.

To permit a consistent comparison of the two technologies, the FW plant has been designed to co-produce the same amount of hydrogen and electric power as the E-Gas based plant; in addition, its gasifier has been designed to operate with similar support systems e.g. the FW plant utilizes the same coal-water slurry feed, cryogenic oxygen supply, fire-tube boiler cooling, syngas particulate removal (candle filter and pre-cleaner cyclone), high and low temperature water gas shifters, and PSA systems used by the E-Gas plant. The FW plant syngas flow rate is slightly less than (~10 per cent) that of the E-Gas plant and, with the plants incorporating similar equipment systems and outputs, the cost of the FW plant was derived, for the most part, from the E-Gas co-production plant cost estimate. Where necessary, however, Parsons made adjustments for differences in flow rates and the deletions or additions of some equipment. The major equipment changes, which were priced by FW, included:

- 1.) In the first equipment train the E-Gas plant gasifier, fire-tube boiler, and char recycle systems were replaced by the cost of FW's comparable systems and unneeded equipment was deleted i.e. water scrubber, acid gas removal, hydrogen sulfide gas concentrator, Claus plant, tail gas recycle systems, etc.
- 2.) In the second or power producing equipment train, which, in the case of the E-Gas plant, extends from the slurry and oxygen feed through the gas turbine, HRSG, and stack, the

equipment was replaced by a CFB boiler system, which extends from coal and air supply through the stack.

FW has built several atmospheric pressure CFB gasifiers (largest has a 70 MWt output [3-2]) and one PCFB gasifier; the latter operated at 360 psig and was provided for the world's first biomass fueled IGCC plant [3-3]. Since it is significantly smaller in size than that required by the co-production plant (20 inch ID versus 60 inch ID), the FW plant cost estimate includes a 10 percent process contingency in the PCFB gasifier and syngas fire-tube boiler cost accounts; in addition, a 3 percent process contingency was applied to its coal-water slurry preparation and feeding account.

The costs of the E-Gas and FW based co-production plants are presented in Sections 4.4 and 5.4 respectively and each is broken down into 14 accounts to permit a detailed comparison of their costs. Since the costs, excepting those provided by FW, originate from prior studies and involve up to six years of escalation, they are best used for relative comparison purposes rather than a prediction of absolute plant costs.

3.5.2 Economic Factors

The costs and economics of the two co-production plants are based on the economic factors listed in Tables 3.4.1 and 3.4.2.

3.5.3 Evaluation Approach

The general estimate basis and assumptions are identified below:

- Total plant costs are expressed in January 2005 dollars.
- The estimate represents a mature technology plant, or "nth plant" (i.e., it does not include costs associated with a first-of-a-kind plant).
- The estimate represents a complete plant facility.
- The estimate boundary limit is defined as the total plant facility within the "fence line"; it begins at the rail road tracks entering the plant and terminates at the piping that begins to transport hydrogen to the adjacent refinery and the high side of the main power transformers.
- Site location is within the Ohio River Valley, southwestern Pennsylvania/eastern Ohio, but not specifically sited within the region.
- Terms used in connection with the estimate are consistent with the EPRI Technical Assessment Guidelines (TAG) [3-4].
- Costs are grouped according to a process/system-oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.

- Design engineering services, including construction management and contingencies are expressed as a percentage of equipment costs delivered to the job site.
- The fuel cost was developed on the basis of a straightforward calculation involving the plant size, plant heat rate, coal higher heating value, coal unit cost, plant annual operating hours, and a levelizing factor.
- The operating and maintenance expenses and consumables costs were developed on a quantitative basis.
 - The operating cost is determined on the basis of the number of operators required.
 - The maintenance cost is evaluated on the basis of relationships of maintenance cost to initial capital cost.
 - The cost of consumables is determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.

Each of these expenses and costs is determined on a first-year basis and levelized at the 10-year life of the plant through application of a levelizing factor to determine the value that forms a part of the hydrogen production cost.

3.5.4 Capital Costs

The capital cost, specifically referred to as total capital requirement (TCR) for the mature co-production plant, was estimated using the EPRI methodology identified in Figure 3.5.4.1. The major components of TCR consist of bare erected cost, total plant cost (TPC), total plant investment (TPI), and owner's costs.

The capital cost was determined through the process of estimating the cost of major equipment items, components, and bulk quantities identified. A Code of Accounts was developed to provide the required structure for the estimate. The Code facilitates the consistent allocation of individual costs and is similar to that used by Parsons in prior studies. The Code facilitates recognition of estimated battery limits and the scope included in each account.

3.5.5 Bare Erected Cost

The bare erected cost level of the estimate, also referred to as the sum of process capital and general facilities capital, consists of the cost of factory equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs. FW provided Parsons the cost of the PCFB gasifier and CFB boiler subsystems delivered to the job site. Parsons determined overall plant costs and economics.

3.5.6 Total Plant Cost (TPC)

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies. Engineering costs represent the cost of architect/engineer services for design/drafting and project construction management services and were set at 8 percent of the bare erected cost on an

individual account basis. The cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Allowances for process and project contingencies are also part of TPC. Based on past experience and depending upon the state of development of the technology involved, Parsons assigned process and project contingencies on an account by account basis.

3.5.7 Total Plant Investment (TPI)

The TPI at date of start-up includes escalation of construction costs and allowance for funds used during construction (AFUDC), formerly called interest during construction, over the construction period. TPI is computed from the TPC, which is expressed on an "overnight" or instantaneous construction basis and a value of 5 percent applied to TPC was assumed for AFUDC.

Figure 3.5.4.1 Components of Capital Cost

3.5.8 Total Capital Requirement (TCR)

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, pre-production (or start-up) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Royalty costs have been assumed to be zero.
- Pre-production Costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant start-up. They are estimated as follows:
 - 1 month of fixed operating costs – operating and maintenance labor, administrative and support labor, and maintenance materials.
 - 1 month of variable operating costs at full capacity (excluding fuel) – includes chemicals, water, and other consumables and waste disposal charges.
 - 25 percent of full capacity fuel cost for 1 month – covers inefficient operation that occurs during the start-up period.
 - 2 percent of TPI – covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.
- Inventory capital is the value of inventories of fuel, other consumables, and by-products, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows:
 - Fuel inventory is based on full-capacity operation for 15 days.
 - Inventory of other consumables (excluding water) is normally based on full-capacity operation for the same number of days as specified for the fuel.
 - ½ percent of the TPC equipment cost is included for spare parts.
- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital). No value is shown because costs are assumed to have been included in the component equipment capital cost.
- Land cost is based on 100 acres of land at \$2,500 per acre.

3.5.9 Capital Cost Estimate Exclusions

Although the estimate is intended to represent a complete plant, there remain several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).
- On-site fuel transportation equipment is not included (i.e., yard locomotive, bulldozers, etc.).
- Allowances for unusual site conditions, such as piling, extensive site access, excessive dewatering, extensive inclement weather, are not included.
- Switchyard (transmission plant) is not included. The cost scope terminates at the high side of the main power transformer.
- Ash disposal facility is excluded; only 3-day ash/slag storage silos have been provided (the ash disposal cost is accounted for in the ash disposal charge as part of consumables costs).
- Royalties.

3.5.10 Operating and Maintenance (O&M) Costs

The costs and expenses associated with operating and maintaining the plant include:

- Operating labor
- Maintenance
 - Material
 - Labor
- Administrative and support labor

The cost of operating labor was estimated from the number of operating jobs (OJ) needed to operate the plant (on an average-per-shift basis) and their average job labor rates. In the absence of quantitative data, both plants were assumed to require the same operating labor hours and, hence, incur the same operating labor cost. Table 3.5.10.1 identifies the labor classifications, number of personnel, and rates that were applied to both plants.

Since the development of the maintenance labor and maintenance material costs are interrelated, their cost bases are discussed together. Annual maintenance costs were estimated per TAG methodology as a percentage of the installed capital cost. Maintenance labor and material costs were estimated to be 2.35 percent of TPC for the FW plant and, because of the need for a third/spare gasifier train, 2.75 percent for the E-Gas plant. These costs were split 40 percent for materials and 60 percent for labor, whereas, administrative costs were set at 45.2 percent of operating labor costs.

The operating labor, maintenance material and labor, and other labor-related costs are combined to give a total operating and maintenance cost which is then divided into two components: 90 percent for fixed O&M, which is independent of operation, and 10 percent for variable O&M, which is proportional to operation. The first-year costs in January 2005 dollars and a 90 percent capacity factor assume normal operation and do not include the initial start-up costs, which are computed separately. A 10-year levelizing factor is applied to the first-year costs and expenses to arrive at appropriate values that contribute to the cost of electricity and hydrogen.

The other operating costs, consumables and fuel, are determined on a daily 100 percent operating capacity basis and adjusted to an annual plant operation basis, equivalent to operating at 100 percent load for 90 percent of the year (plant capacity factor).

The development of the actual values was performed on a Parsons model that is consistent with TAG.

Table 3.5.10.1 Operating Labor for Co-Production Plants

Operating Labor Rate(base)	\$28.00 per hour
Operating Labor Burden	35% of base
Labor Overhead Charge Rate	30% of base
Operating Labor Hours per Year	1,944
Administrative & Support Labor	45.15% of Operating Labor
Operating Labor Requirements (OJ) - 4 Shifts Required	
Category	Number/Shift
Skilled Operator	3
Operator	18
Foreman	3
Lab Techs, etc	2
Total OJs	26

3.5.11 Consumable Operating Costs

Costs included in this category are:

- Consumables
- By-product credit (if applicable)
- Fuel cost

Feedstock and disposal costs are those consumable expenses associated with normal plant operation. Consumable operating costs are developed on a first-year basis and subsequently leveled over a 10-year period. The consumables category consists of water, chemicals, other consumables, and waste disposal.

The "water" component pertains to the acquisition charge for the water required for the plant steam cycle, cooling towers, scrubbers, miscellaneous services, and ash pug mills. The "chemicals" component includes the cost of limestone, catalysts, boiler water treatment, and ammonia.

The "other consumables" component consists of fuel oil and gases. The fuel oil quantity accounts for start-up heaters and miscellaneous users plus fuel for the auxiliary boiler; with the plants being base load units, these costs were assumed small and ignored.

The "waste disposal" component pertains to the cost allowance for off-site disposal of plant solid wastes. Although the ash from the CFB boiler can potentially be used for road construction, structural fill, agricultural fertilizing, etc., the economics of such uses would be highly site dependent. As a result, no credit was taken for the potential sale of CFB boiler ash. The E-Gas Plant produces both elemental sulfur and slag; similar to the CFB boiler ash, the slag was assumed to have no value, whereas, the sulfur is considered a byproduct of the plant that can be sold for \$75/ton.

Table 3.5.11.1 Consumable Unit Costs

	Unit Cost
Water per 1,000 gals	\$0.82
Chemicals	
Water Treatment per lb	\$0.20
Limestone per Ton	\$18.00
COS Catalyst per CuFt	\$0.00
Shift Catalyst per CuFt	\$450.00
Claus Catalyst per CuFt	\$325.00
Hdrogenation Catalyst per CuFt	\$290.00
Amine per lb	\$1.09
Ammonia per lb	\$0.22
Other	
Supplemental Fuel per MMBtu	\$15.00
Waste Disposal	
Ash per ton	\$12.00
Slag per ton	\$12.00

3.5.12 By-Product Credits

The electricity produced by both plants and the elemental sulfur produced by the E-Gas based plant are sold to produce a “by-product” revenue stream for their plants. Electricity and sulfur yearly production rates are based on a 90 percent plant capacity factor and their sell prices are assumed to escalate at 2.5 percent per year from year 2005 values of \$45 per MWhr and \$75 per ton respectively.

3.5.13 Fuel Cost

The fuel cost is based on the plant full load coal flow rate with the plant operating 24 hours per day 365 days per year and an overall capacity factor of 90 percent. Coal costs are assumed to escalate at 0.1 percent per year from a year 2005 value of \$1.61 per million Btu.

3.5.14 Total Production Cost

This is the sum of fixed O&M, variable O&M, fuel, and consumables costs less by-product credits. It is presented on both a first year (2009) and a levelized 10-year basis.

3.5.15 Carrying Charges

This is the sum of return on debt, 12 percent return on equity, federal and state income taxes, book depreciation, property taxes, and insurance. It is presented on a levelized 10-year basis.

3.5.16 Cost of Hydrogen

The revenue requirement method is widely used in the electric utility industry to perform an economic analysis of a prospective new power plant. This method permits the various dissimilar

components of a new plant to be incorporated into a value that can be compared with various alternatives. From a cost of electricity standpoint the revenue requirement figure-of-merit is the levelized (over plant life) coal pile-to-bussbar cost of electricity expressed in mills/kWh. The value, based on EPRI definitions and methodology, includes the TCR, which is represented in the levelized carrying charge (sometimes referred to as the fixed charges), 10-year levelized fixed and variable operating and maintenance costs, 10-year levelized consumables operating costs, and 10 year levelized fuel cost.

A similar revenue requirement analysis was performed to determine the cost of producing hydrogen on a dollar per million Btu basis; in this analysis, however, credit was included for the sale of the electricity and sulfur co-produced with the hydrogen.

The bases for calculating plant capital investment and revenue requirements are given in Figure 3.5.4.1. The total plant cost (TPC) and revenue requirement (hydrogen production cost), are the principal cost and economic outputs of the study.

The levelized carrying charge, applied to TCR, establishes the required revenues to cover return on equity, interest on debt, depreciation, income tax, property tax, and insurance. Levelizing factors are applied to the first-year fuel, O&M, and consumables costs to yield 10-year levelized costs. A long-term inflation rate of 2.5 percent per year was assumed in estimating the cost of capital and in estimating the life-cycle revenue requirements for other expenses (except that fuel was escalated at 0.1 percent per year).

To represent these varying revenue requirements for fixed and variable costs, a "levelized" value was computed using the "present worth" concept of money based on the assumptions shown in Table 3.5.2.1. By combining costs, by-product credits, and carrying charges a levelized 10 year cost of producing hydrogen was calculated by the following:

$$\text{Levelized Hydrogen Production Cost} = (\text{LCC} + \text{LFOM} + \text{LVOM} + \text{LCM} - \text{LLB} + \text{LFC}) / \text{Tons of Hydrogen Produced}^*$$

LCC = Levelized Carrying charge, \$/yr
 LFOM = Levelized Fixed O&M, \$/yr
 LVOM = Levelized Variable O&M, \$/yr
 LCM = Levelized Consumables*, \$/yr
 LBPC = Levelized By-product credit* (if any), \$/yr
 LFC = Levelized Fuel costs*, \$/yr

* all for a 90 percent plant capacity factor

4.0 Entrained Flow Gasifier Based Co-Production Plant

4.1 Plant Overview, Performance, and Emissions

Overview

Figure 4.1.1 is a simplified a process block diagram of the entrained flow gasifier co-production plant conceptually designed by Parsons. The plant incorporates three 50 percent capacity gasifier equipment trains. Although the trains operate in parallel at identical conditions, only two trains are in steady state operation at any point in time. The first operating train provides syngas for hydrogen production, whereas, the second train provides syngas for power generation. In the 1990s coal fueled, single train, entrained flow IGCC demonstration plants were built by several different manufacturers. Depending upon the plant, and despite several yeas of operation, plant availabilities are in 70s and 80s percent. To achieve a plant availability of at least 90 percent, the plant has been provided with a spare gasifier equipment train [2-1], [2-2]. This spare or third train is physically located along side of the other two; it is brought on line for either hydrogen or power generation when one of the other two trains has been shut down for maintenance. To allow for future component improvements/advances, the economics of the entrained flow co-production plant have been determined both with and without the spare train.

All three gasifiers are oxygen blown and operate with coal injected as a 35 weight percent coal - 65 weight percent water slurry. The gasifiers draw their oxygen from a common header supplied by two 50 percent capacity, conventional, cryogenic ASUs. Two 100 percent capacity milling systems crush the coal to size, mix it with water, and deliver it to two product tanks for transfer to the plant's three slurry feed tanks. Each 50 percent capacity gasifier equipment train consists of a coal-water slurry feed tank, slurry pumps, a slurry heater, a two stage entrained flow gasifier, a slag rejection system, a fire tube boiler/syngas cooler, a cyclone, a candle filter, a water scrubber, and a fines return system. The gasifiers operate at identical conditions and produce 514 psia 1750°F syngas that is cleaned of gas entrained particulate and cooled to 285°F by the downstream equipment. After cooling, twenty percent of the syngas is compressed and used to transport the char fines, captured by the cyclone and filter, back to and into the gasifier to increase the gasifier carbon conversion efficiency. The remaining 80 percent then proceeds to its respective gas processing section.

The syngas from the first gasifier train proceeds to the hydrogen production equipment train where it undergoes steam injection, reheating, three stages of water gas shifting (two high temperature and one low temperature), gas cooling, amine washing for acid gas removal (AGR), and PSA. The PSA system separates the hydrogen from the syngas and yields 99.95 percent pure, 370 psia, 117°F hydrogen for sale to a near by refinery at a rate of 21,731 lb/hr (261 tons/day). The ~20 psia low Btu vent/purge gas from the PSA is fired in a boiler that generates steam for process use and to drive a 50.1 MWe steam turbine; in generating this steam the flue gas from the boiler is cooled to 250°F and discharged to one of the plant's two stacks.

Figure 4.1.1 Entrained Flow Plant Process Block Diagram

The syngas from the second train proceeds to the power generation equipment train where it undergoes reheating, COS hydrolysis, cooling, an amine AGR wash, reheating, and humidification; the humidified gas at 390 psia and 535°F fuels a General Electric 7FA gas turbine that generates 190 MWe. A heat recovery steam generator (HRSG) downstream of the gas turbine cools the 1057°F turbine exhaust to 278°F, produces steam to drive a 98.9 MWe steam turbine, and discharges its gas to the second, larger plant stack.

The amine washes strip the syngas streams of their hydrogen sulfide and, in doing so, absorb other gases. The rich/used amine solvent from each absorber is pumped to a common tower where steam stripping releases the absorbed gases. The regenerated/lean solvent is then pumped back to each absorber, whereas, the stripper off gas undergoes another amine wash designed to separate the hydrogen sulfide from the other gases. With much of the other gases removed, the hydrogen sulfide rich gas proceeds to a Claus furnace where it is burned with oxygen. The exhaust/tail gas from the Claus furnace is cooled to condense/remove sulfur, hydrogenated, cooled again, compressed, and injected back into the gasifiers.

Performance

Figures 4.1.2 and 4.1.3 identify the flow rates, pressures, and temperatures of the plant's air/gas side flow paths; syngas, char fines, and slag compositions are not shown as they are considered E-Gas proprietary data. Tables 4.1.1 and 4.1.2 present the plant performance and parasitic power loads as determined by Parsons; the gas and steam turbines have a combined gross power output of 346.0 MWe and, with a parasitic power draw of 94.1 MWe, results in a net plant output of 251.9 MWe. To generate this power and produce 21,703 lb/hr of hydrogen the plant consumes coal at the rate of 368,938 lb/hr and operates with an effective thermal efficiency of 47.6 percent (HHV basis).

Figure 4.1.2 Entrained Flow Plant Process Stream Locations

Stream Number	1	2	3	4	5	6	7A	7B	8	9
Stream Location	Slurry Prep	Slurry Prep	Gasifier	ASU	ASU	ASU	Gasifier	Gasifier	Gasifier	Gasifier
Temperature, F	59	59	300	59	296	90	205	360	861	250
Pressure, psi	14.7	14.7	550.0	14.7	359.0	30.0	815.0	600	750.0	14.7
Medium	coal	water	slurry	air	nitrogen	oxygen	oxygen	nitrogen	Claus tail gas	slag
Flow Rate, Klb/hr										
	Gas			1293.428	482.811	4.995	291.846	3.787	46.333	
	Solids	368.938	368.938							37.934
	Liquid		164.602	164.602						
Total Flow, Klb/hr	368.938	164.602	533.540	1293.428	482.811	4.995	291.846	3.787	46.333	37.934
Stream Number	10	11	12	13	14	15	16	17	18	19
Stream Location	Gasifier	Filter Outlet	Scrubber	Scrubber	Scrubber	Gasifier	Power Train	Drains	AGR	AGR
Temperature, F	1750	690	330	150	285	365	390**	varies	103	110
Pressure, psi	514.4	484.2	465.2	465.2	447.7	605.0	447.7	varies	412.7	402.7
Medium	mixture	syngas	syngas	water	syngas	syngas	syngas	condensate	syngas	syngas
Flow Rate, Klb/hr										
	Gas	1039.352	1039.352	1039.352	989.969	197.994	395.988		365.661	338.492
	Solids	*				*				
	Liquid			5.180				30.326		
Total Flow, Klb/hr	1039.352	1039.352	1039.352	5.180	989.969	197.994	395.988	30.326	365.661	338.492
Stream Number	20	21	22	23	24	25	26	27	28	29
Stream Location	Humidifier	GT Burner	GT Inlet	GT Exhaust	HRSG Outlet	H ₂ Train	H ₂ Train	HT Shift Inlet	Drains	AGR
Temperature, F	150	535	59	1057	278	285	500	550**	varies	103
Pressure, psi	445.0	390.0	14.7	15.1	14.8	447.7	500.0	442.7	varies	389.8
Medium	water	syngas	air	exhaust	exhaust	syngas	steam	syngas	water	syngas
Flow Rate, Klb/hr										
	Gas		402.322	3237.510	4,122.643	395.988	211.514	607.502		496.646
	Solids									
	Liquid	68.932							110.856	
Total Flow, Klb/hr	68.932	402.322	3237.510	4122.643	4,122.643	395.988	211.514	607.502	110.856	496.646
Stream Number	30	31	32	33	34	35	38+	39	40	41
Stream Location	AGR	PSA Outlet	PSA Outlet	Finned Boiler	Finned Boiler	Finned Boiler	Recooperator	Claus Plant	Claus Plant	Tail Gas Unit
Temperature, F	110	117	97	105	59	250	103	120	270	120
Pressure, psi	378	369.8	19.4	20.0	14.7	15.5	382	30.0	14.7	167
Medium	syngas	hydrogen	PSA vent	sweet gas	air	flue gas		conc H ₂ S	sulfur	condensate
Flow Rate, Klb/hr										
	Gas	341.522	21.703	319.739	137.106	687.736	1,147.842	45.266		
	Solids								10.590	
	Liquid									3.448
Total Flow, Klb/hr	341.522	21.703	319.739	137.106	687.736	1147.842	182.372	45.266	10.59	
*not disclosed	**after reheat	+Stream Numbers 36 & 37 deleted								

Figure 4.1.3 Entrained Flow Plant Process Stream Operating Conditions

Table 4.1.1 E-Gas Entrained Flow Plant Performance Data

Key Flow Rates Entering Plant, lb/hr	
Coal (As Received)	
To Gasifier # 1	184,469
To Gasifier # 2	184,469
To CFB Boiler	
	Total 368,938
Oxygen	
To Gasifier # 1	145,923
To Gasifier # 2	145,923
To Claus Plant	4,995
	Total 296,841
Limestone, lb/hr	
Water, MMgal/d	2.9
Discharges, lb/hr	
Water	36,653
Slag / Ash	37,934
Sulfur	10,608
Stack Flue Gas	5,270,485
Gross Power, KWe	
7 FA Gas Turbine	197,000
Steam Turbine	149,020
	Total 346,020
Parasitic Power, KWe	94,120
Net Plant Power Output, kWe	251,900
H2 Production Rate, lb/hr	21,703
Plant Performance	
Thermal Input*, Btu/hr	4.593E+09
Equivalent Output**, Btu/hr	
Power	8.595E+08
Hydrogen	1.326E+09
	Total 2.185E+09
Effective Thermal (HHV) Efficiency, %	47.58

*12,450 Btu/lb Pittsburgh 8 at 2.89% sulfur

**Hydrogen at 61,095 Btu/lb and Power at 3,413 Btu/KW

Table 4.1.2 E-Gas Entrained Flow Plant Parasitic Power (KWe)

	H2 Train	Power Train	Totals	Totals*
Coal/Limestone Handling	230	230	460	
Gasifier Coal Milling	470	470	940	
Coal Slurry Pumps	200	200	400	
Slag Handling and Dewatering	190	190	380	
				2,180
Air Separation Unit Auxiliaries	15,600	15,600	31,200	
Oxygen Compressor	8,580	8,580	17,160	
Main Nitrogen Compressor		24,500	24,500	
				72,860
Fines Recycle Gas Blower	840	840	1,680	
Tail Gas Recycle Blower	1,330	1,330	2,660	
				4,340
Fired Boiler Air Fan	1,250		1,250	
				1,250
Condensate Pumps	100	100	200	
HP Boiler Feedwater Pump	570	1,740	2,310	
LP Boiler Feedwater Pump	80	150	230	
Circulating Water Pump	740	1,400	2,140	
Cooling Tower Fans	460	780	1,240	
				6,120
Humidification Tower Pump		100	100	
Humidification Makeup Pump		80	80	
Flash Bottoms Pump	50	100	150	
Scrubber Pumps	400	400	800	
				1,130
Amine Unit Auxiliaries	970	970	1,940	
Claus Plant/TGTU Auxiliaries	200	200	400	
				2,340
Gas Turbine Auxiliaries		400	400	
Steam Turbine Auxiliaries	200	400	600	
Transformer Losses	150	750	900	
				1,900
Miscellaneous Balance-of-Plant	1,000	1,000	2,000	
				2,000
Totals	33,610	60,510	94,120	94,120

*Totals by Process Area

Emissions

The emissions of the entrained flow plant are the total of those contained in the exhaust from its GE 7FA gas turbine and its PSA vent gas fired boiler. The Wabash IGCC Demonstration Plant, which incorporated an E-Gas gasifier, an amine scrubber for sulfur capture, a Claus Plant for sulfur recovery, and a GE 7FA gas turbine, operated with SO₂ and NO_x emissions rates of 0.13 and 0.08 lb/MMBtu respectively [4-1]. To reduce those emission rates, the entrained flow gasifier based plant recycles the Claus Plant tail gas back to the gasifier and injects nitrogen into the gas turbine combustor. Parsons projects that these steps will reduce the co-production plant SO₂ emission rate to 0.023 lb/MMBtu (99.5 percent sulfur capture efficiency) and the NO_x emission rate to 0.067 lb/MMBtu (15 ppmvd). Using these new values, together with those projected for the PSA vent gas fired boiler, Parsons determined the plant emissions on a pound per hour basis and then expressed them on a total plant heat input basis; Parsons' plant emission estimate is given in Table 4.1.3

Table 4.1.3 E-Gas Entrained Flow Plant Emissions

	Gas Turbine	Fired Boiler	Plant Totals
SO ₂			
% Capture			99.5
lb/hr			106.9
lb/MMBtu			0.023
NO _x			
lb/hr	122	72	194
lb/MMBtu	0.066		0.042
CO			
lb/hr	203	94	297
lb/MMBtu	0.110	0.200	0.065
Particulate			
lb/hr			3.7
lb/MMBtu			0.0008

4.2 Process and System Description

The entrained plant consists of numerous systems that work together to produce hydrogen and electricity. For cost estimating purposes those systems have been divided into 14 processing blocks or cost accounts that are presented in Appendix A. In addition to facilitating cost estimating, these accounts also facilitate a detailed process description of the plant as follows:

Coal Receiving and Handling

Pittsburgh No 8 coal, crushed to a 6 inch by zero size, is delivered to the site in 100 car unit trains. The coal is unloaded, moved to the storage pile, and reclaimed by the conventional equipment listed in Account 1; included in this account is a trestle bottom dumper, receiving hoppers, feeders, conveyors, and stacker/reclaimer. The reclaimed coal is crushed to a 1 inch by zero size in two steps and transferred to two three-day storage silos that supply coal to the coal-water slurry preparation and feeding subsystems.

Coal-Water Slurry Preparation and Feeding

The coal-water slurry preparation and feeding equipment is listed in Account 2. Slurry preparation equipment consists of two 100 percent capacity trains of day silos, rod mills, and slurry product tanks that operate in parallel, crush one inch by zero coal to a minus 200 mesh size, and mix it with water to form a 35 weight percent coal - 65 weight percent water slurry. From the product tanks the slurry is pumped to three 50 percent capacity feed trains, each connected to a gasifier and consisting of a slurry storage feed tank, slurry pumps, and slurry heaters. Each feed train can deliver slurry to its respective gasifier at a full load flow rate of 266,770 lb/hr at 500 psia and 300°F.

Oxygen and Nitrogen Supply Systems

The plant utilizes two 50 percent capacity oxygen supply systems that operate in parallel at identical conditions. Each of the two oxygen supply system incorporates an electrically driven compressor that supplies 70 psia 210°F air to a conventional, cryogenic ASU. The ASU includes a liquid oxygen storage tank to guard against short term disruptions and each ASU supplies 95 percent pure oxygen to its own electrically driven boost compressor. The latter pressurizes the 60°F oxygen from 15 to 815 psia and discharges to a header shared with the other boost compressor; the two operating and one spare 50 percent capacity gasifiers draw their oxygen from this supply header at a total rate of 291,846 lb/hr. The ASUs also supply a small stream of 60°F oxygen (4,995 lb/hr) to the Claus Furnace.

The gas turbine requires nitrogen injection to control its NO_x emissions. As a result, 60°F nitrogen from the ASU is compressed to 359 psia for delivery to the gas turbine burner at a rate of 482,811 lb/hr; a slip stream of nitrogen from the ASU is also compressed and available for miscellaneous plant uses.

The equipment making up the oxygen and nitrogen supply systems are listed in Account 4B.

Entrained Flow Gasifier

The plant utilizes three 50 percent capacity gasifiers (see Account 4A for equipment) that operate in parallel at identical conditions but independent of each other. The first produces syngas for hydrogen production, the second produces syngas for electric power generation, and the third is a spare that can be used for either hydrogen or power production when one of the other gasifiers is shut down. The gasifiers are entrained flow type units as exemplified by the E-GasTM gasifier at the Clean Coal Technology Wabash River Repowering Project. Each gasifier is a two stage unit and its 266,770 lb/hr slurry feed is split between the first and second stages. Typically the slurry proportions 78 percent to the ~2500°F first stage, and 22 percent to the second stage. Oxygen is delivered to each gasifier at a full load rate of 145,923 lb/hr and, because of the high temperature of the first stage, a molten slag is produced that collects on and runs down the walls of the unit. At the bottom, the molten slag drains to a water bath, solidifies, sinks to the bottom of the bath, is removed from the process, crushed, and transferred to storage silos for disposal. The slurry injected in the second stage of the unit cools the syngas and the gas exits from the top of the unit at 514 psia and 1750°F at a rate, excluding entrained particulate/char fines, of 519,676 lb/hr. After cooling, the collected char fines are injected back into the first stage of the gasifier with cold (285°F) recycled syngas.

Syngas Cooling and Particulate Removal

After exiting the gasifier the syngas flows vertically down the tubes of a fire-tube type boiler/syngas cooler, which, by the generation of steam, cools the syngas and entrained particulate to 690°F. The cooled syngas proceeds to a cyclone that pre-cleans the gas/removes the coarser particulate before the gas enters a candle filter for the removal of all remaining particulate. The filter consists of an array of vertical hanging, porous, ceramic candles located inside of a pressure vessel. Similar to a bag house filter, the particulate collect on the outside of the candles. On reaching a predetermined pressure drop, the candles are cleaned (dust blown off) by a back-pulse of clean gas (recycled syngas) and the particulate fall to and drain from the bottom of the vessel. A surge hopper is provided both under the cyclone and under the filter to collect their respective coal and char particles. The collected material is transported back to and injected into the gasifier using recycled cold syngas.

After exiting their respective candle filters the two 690°F syngas streams are separately cooled to 285°F via tubular heat exchangers and a water scrubber and passed through a series of valves that control the gasifier pressure, divert syngas to flare, isolate the gasifier from downstream components and the spare gasifier train, and provides 20 percent syngas recirculation to transport char, collected by the pre-cleaner cyclone and filter, back to the gasifier.

The syngas cooling and particulate removal equipment is included in Account 4A.

Syngas for H₂ Production

This stream is processed by the equipment listed in Account 5A. After passing through the water scrubber, the syngas undergoes steam injection, reheat to 550°F, and three stages of water gas shifting. Since the water gas shift reaction is exothermic a series of heat exchangers control the syngas temperature and ultimately reduce it to 110°F for delivery to a conventional PSA system for separation of the hydrogen. Condensate, formed during this cooling, contains varying amounts of contaminants i.e. H₂S, NH₃, HCl, etc. and this “gray water” is sent to a central water treatment system for contaminant removal by steam stripping; after cleaning, the water is supplied to the slurry preparation system and the stripping off-gas is sent to the Claus furnace. Despite the condensation, a considerable amount of contaminants will remain in the cooled syngas. Although the PSA will prevent them from contaminating the hydrogen, their presence in the PSA vent gas, which is burned in the fired boiler, can cause a stack gas emission problem. To prevent this, the syngas undergoes acid gas removal before delivery to the PSA.

The acid gas removal system appears under Account 5B; it consists of a single stage amine absorption tower that strips the syngas of H₂S. With the H₂S removed, the syngas proceeds to the PSA system at a rate of 341,522 lb/hr. The PSA separates the hydrogen and releases it at 369.8 psia for delivery/sale to the refinery at a rate of 261 tpd. The 319,739 lb/hr of 19.4 psia low Btu PSA purge/vent gas is burned along with 137,106 lb/hr of sweet gas with 687,736 lb/hr of air in a fired boiler that discharges 250°F flue gas to the smaller of the plant’s two stacks.

The fired boiler, together with the various upstream gas coolers, generates steam at several different pressure levels for process use and to drive a 50.1 MWe steam turbine. The latter

operates with a 408,296 lb/hr 950°F 1250 psig throttle flow. The fired boiler and steam turbine are included under Account 7.

Syngas for Power Production

This stream is processed by the equipment listed in Account 5C. After exiting its water scrubber, the syngas is reheated to 390°F, passed through a COS hydrolysis unit to convert COS to H₂S, cooled to 103°F, and delivered to an amine absorption tower for removal of acid gases. The amine absorber strips the syngas of H₂S and the cleaned syngas is humidified and reheated to 535°F for delivery to the gas turbine combustor.

Condensate is formed during the cooling of the syngas to 103°F and the condensate contains contaminants i.e. HCN, NH₃, halogens (HCl and HF), etc. and this “gray water” is sent to a central water treatment system; after cleaning, the water is supplied to the slurry preparation system and the stripping off-gas is sent to the Claus furnace.

H₂S Processing

The H₂S processing equipment is listed in Account 5C. The H₂S rich amine solvent streams from the hydrogen and power production acid gas removal sections are pumped to a common tower/reboiler where, after mixing, they are steam stripped/heated with 45,210 lb/hr of 65 psia steam; this releases hydrogen sulfide and other absorbed gases and allows the amine, now regenerated (lean solvent), to be pumped back to their respective absorber towers for continued use. The hydrogen sulfide content of the reboiler off-gas is less than optimum for the Claus furnace sulfur recovery and the gas undergoes another wash to remove the extraneous gases. The reboiler associated with this concentrating wash consumes another 12,691 lb/hr of 65 psia steam and the hydrogen sulfide rich off-gas is delivered to and burned with oxygen in the Claus furnace. The Claus furnace exhaust gas is passed through a series of coolers and catalytic reactors to recover elemental sulfur for sale as a by-product of the plant. Since sulfur recovery is not 100 percent, the gas, after cooling to 318°F, is hydrogenated, cooled, compressed, and injected back into the gasifiers at 861°F.

Gas Turbine

The plant incorporates a single General Electric Model 7FA combustion turbine that is listed under Account 6. The gas turbine is fueled with 402,322 lb/hr 535°F, 390 psia, humidified syngas produced/processed by the syngas power production section of the plant. Nitrogen, supplied by the ASU, is injected into the gas turbine combustion process at a rate of 482,811 lb/hr to control NO_x emissions. The machine is an axial flow, constant speed unit possessing variable inlet guide vanes. and produces 197 MWe of power.

Heat Recovery Steam Generator

The gas turbine discharges 1057°F exhaust gas to a heat recovery steam generator (HRSG) at a rate of 4,122,643 lb/hr. The HRSG is a three pressure unit containing high pressure (HP), intermediate pressure (IP), and low pressure (LP) steam drums. The HRSG cools the gas turbine exhaust to 278°F and, working in conjunction with the syngas cooler and other gas coolers, produces 1005°F superheat and reheat steam to drive a steam turbine. The flue gas from the HRSG discharges to the plant's second and larger stack. The HRSG and stack are listed under Account 7.

Fired Boiler

The fired boiler and its auxiliary equipment are also listed under Account 7. The fired boiler is fueled with the 19.4 psia low Btu vent gas/tail gas from the PSA at the rate of 319,739 lb/hr and, in addition, receives the 137,106 lb/hr sweet gas from the H₂S concentration step. Air supplied by a fan at the rate of 687,736 lb/hr and 78°F supports the combustion of the vent gas and the boiler cools the combustion exhaust gas to 250°F. Working together with the upstream syngas cooler and other gas coolers, the fired boiler produces steam for process use and to drive a small steam turbine. The flue gas from the waste heat boiler, cooled to 250°F, discharges to the smaller of the plant's two stacks.

Steam Turbines and Steam Condensers

As listed under Account 8 the plant incorporates two steam turbine generators and two steam condensers that operate in parallel and independent of each other; the larger one produces 98.9 MWe of power and is part of the power production section of the plant; the other produces 50.1 MWe of power and is part of the hydrogen production part of the plant. The former is supplied with 1600 psig 1000°F steam from the gas turbine HRSG at a rate of 589,262 lb/hr and incorporates a single stage of reheat to 1000°F. It consists of tandem HP, IP, and LP sections connected via a common shaft that drives a 3,600 RPM hydrogen cooled generator. The generator is a synchronous type unit that operates with an efficiency of 98 percent.

The smaller steam turbine is supplied with 1250 psig 950°F steam from the fired boiler at a rate of 408,296 lb/hr. Being a relatively small unit, there is no reheat and it produces only 50.1 MWe of power.

A single pass, horizontal type condenser is provided under each steam turbine to condense their exhaust steam and provide condensate to their respective feedwater heating systems. The larger condenser supports the power generation section of the plant and condenses steam at a rate of 530,284 lb/hr at a back pressure of 1 psia; the smaller unit supports the hydrogen section of the plant and condenses steam at a rate of 408,296 lb/hr at 1 psia. In both units the steam is indirectly cooled by heating circulating water for delivery to a mechanical draft cooling tower.

Condensate and Feedwater Systems

The heated discharge water from each condenser proceeds to a common, mechanical draft, evaporative cooling tower that transfers the heat of condensation to the atmosphere. The cooling tower consists of multiple cells that are operated as required to meet the plant cooling load.. Four 50 percent capacity circulating water pumps (two for the small condenser and two for the large condenser) pump cooled water to the condensers. This equipment is listed under Account 9.

Each condenser is provided with two 50 percent capacity motor driven pumps that extract condensate from their respective hot wells and pump it to deaerating sections/tanks. Each tank in turn is provided with two 50 percent capacity motor driven boiler feed pumps that supply feedwater to their respective boilers. This equipment is listed under Account 3A.

4.3 List of Plant Major Equipment

The major pieces of equipment required by the three gasification train co-production plant have been subdivided into 14 accounts and are tabulated in Appendix A; those 14 accounts served as the basis for the plant cost estimates presented in Section 4.4.

4.4 Plant Costs and Economic Analysis

Parsons is an architect engineering company that designs and supplies a variety of plants including those directed at power production, chemical production, and petrochemical refining. This background gives them an extensive database for estimating equipment supply and erection costs, plant performance, and overall plant costs. As a result, Parsons has conducted numerous studies for the DOE in which they conceptually designed and determined the performance and economics of IGCC plants designed for power production or hydrogen production. In these studies the gasifier developer provided performance, size, and cost data for its component(s) and Parsons sized the balance of the equipment required by the plant and determined overall plant costs and economics. Using cost data from these previous studies together with “in-house” data, Parsons determined the cost and economics of the entrained flow gasifier based co-production plant in accordance with the methodology presented in Section 3.5.

Table 4.4.1 presents the cost of E-Gas co-production plant by account total (for costs at the sub-account level the reader is referred to Appendices A and B – the plant with and without a spare gasifier equipment train). When provided with a spare train of gasification equipment (total of 3 trains), Parsons estimates the plant will have a total plant cost of \$678.5 million in year 2005 dollars. Allowing for technology and reliability improvements that may allow deletion of one train of gasification equipment, the plant cost reduces to \$647.8 million. Consumables and operating requirements and costs are presented in Tables 4.4.2 and 4.4.3. The economics of the plants are presented in detail in Tables 4.4.4 and 4.4.5. Table 4.4.6 summarizes the key economic data of both plants; the 251.9 MWe of power and 10,608 lb/hr of sulfur produced by the plant, which are assumed to be sold for \$45/MWhr and \$75/ton respectively, provide valuable revenue streams that enable the plants to sell their hydrogen at a 10 year levelized cost of \$7.06 and \$6.06 per million Btu respectively.

Table 4.4.1 E-Gas Co-Production Plant TPC in Thousands of Year 2005 Dollars

Account #	Account Title	3 Gasifier Equip Trains	2 Gasifier Equip Trains
1	Coal & Sorbent Handling	32,369	32,369
2	Coal-Water Slurry Prep & Feed	40,909	40,909
3	Feedwater & Misc BOP Systems	19,766	19,766
4	Gasifier & Accessories	211,715	181,795
5	H2 Separation, Gas Cleanup, & Piping	91,051	91,051
6	Combustion Turbine & Accessories	58,099	58,099
7	HRSG, Ducting, & Stack	49,885	49,885
8	Steam Turbine Generator	31,919	31,919
9	Cooling Water System	13,922	13,922
10	Slag/Ash Handling Systems	17,477	17,477
11	Accessory Electric Plant	55,916	55,096
12	Instrumentation & Control	26,193	26,193
13	Improvements to Site	10,720	10,720
14	Buildings & Structures	18,559	18,559
	Total	678,500	647,760

Table 4.4.2 E-Gas Plant Operating and Consumables Requirements

OPERATING REQUIREMENTS				
			WMM	1/21/06
H2 & Electric Coproduction -E-Gas IGCC				
Operating Labor Rate(base)	\$28.00	per hour		
Operating Labor Burden	35%	of base		
Labor Overhead Charge Rate	30%	of base		
Operating Labor Hours per Year	1,944			
Administrative & Support Labor	45.15%	of Operating Labor		
Operating Labor Requirements (OJ) per Shift - 4 Shifts				
Category	1 Unit per Mod		Total Plant	
Skilled Operator	3		3	
Operator	18		18	
Foreman	3		3	
Lab Techs, etc	2		2	
Total OJs	26		26	
CONSUMABLES				
H2 & Electric Coproduction -E-Gas IGCC				
	Consumption		Unit	
	Initial	Per Day	Cost	
Water (per 1,000gals)	N/A	2,917	\$0.82	
Chemicals				
Water Treatment (lbs)	211,845	7,061	\$0.20	
Limestone (Tons)	0	0	\$18.00	
COS Catalystr (CuFt)	340	0.31	\$575.00	
Shift Catalystr (CuFt)	757	1.30	\$450.00	
Claus Catalyst (CuFt)	1,070	1.47	\$325.00	
Hydrogenation Catalyst (CuFt)	290	0.40	\$290.00	
Amine (lbs)	6,480	216	\$1.09	
Ammonia (lbs)	0	0	\$0.22	
Other				
Supplemental Fuel (MMbtu)	N/A	0	\$15.00	
Waste Disposal				
Ash (Tons)	N/A	0	\$12.00	
Slag (Tons)	N/A	455	\$12.00	
BYPRODUCTS				
Excess Electric Generation (MWh)	N/A	6,046	\$45.00	
Sulfur (Tons)	N/A	127	\$75.00	
FUEL				
Fuel - Coal (Tons)	66,409	4,427	\$40.00	

Table 4.4.3 E-Gas Plant Operating and Consumables Costs

Operation, Maintenance, and Supplies Costs Case: H2 & Electric Coproduction -E-Gas IGCC Plant Size: 251.90 MW, net 260.4 H2 Tons / Day						
						1/21/06 Jan 2005 Dollars
Item / Description	Qty	Qty	Qty	Qty	Qty	\$ x 1000
Operating Labor	26	4	\$54,432	1.35	1.30	\$9,935
# operators/shift x # shifts x \$/year x Benefits x Overhead						
Maintenance Labor	0.4	\$678,500	2.7500%			\$7,464
%of Cap Cost X \$Cap Cost x 1000 X Maint %						
Maintenance Materials	0.6	\$678,500	2.7500%			\$11,195
%of Cap Cost X \$Cap Cost x 1000 X Maint %						
Administrative & Support Labor	45.2%	\$9,934,929				\$4,486
% X Operating Labor						
CONSUMABLES - 1st Year						
Water	2,917	365	90%	\$815		\$781
mgd x Day/Yr x CF x \$/mgd						
Chemicals						
Water Treatment	7,061	\$0.20	365	90%		\$464
lbs/day x \$/lb x Days/Yr x CF						
Limestone	0	\$18.00	90%			\$0
Tons/day x \$/Ton x 365 x CF						
Catalysts-Variou s	3.48	\$390	90%			\$446
CuFt/day x \$/CuFt x 365 x CF						
Amine	216	\$1.09	90%			\$77
lbs/day x \$/lb x 365 Days/Yr x CF						
Ammonia	0	\$0.00	90%			\$0
lbs/day x \$/lb x Days/Yr x CF						
Subtotals						\$987
Other .						
MMBTU/day x \$/MMbtu x 365Days/Yr x CF						
Gases	0	\$0.00	90%			\$0
cuft/day x \$/cuft x 365Days/Yr x CF						
Subtotals						\$0
Waste Disposal						
Ash	0	\$12.00	90%			\$0
Tons/day x \$/Ton x 365 x CF						
Slag	455	\$12.00	90%			\$1,794
Tons/day x \$/Ton x 365 x CF						
Subtotals						\$1,794
Totals						3,562

Table 4.4.4 E-Gas Plant Hydrogen Production Cost (3 Train Plant)

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY				
TITLE/DEFINITION		1/21/06		
Case:	H2 & Electric Coproduction -E-Gas IGCC			
Plant Size:	251.90 (MW,net)	Hydrogen(H2)	260.4	Tons/Day
Fuel(type):	Pittsburgh #8	Fuel Cost:	1.61	(\$/MMBtu)
Design/Construction:	4 (years)	BookLife:	20	(years)
TPC(Plant Cost) Year:	2005	TPI Year:	2007.0	(Jan.)
Capacity Factor:	90.0%			
<u>CAPITAL INVESTMENT</u>		<u>\$x1000</u>	<u>\$x1000/H2TPD</u>	
Process Capital & Facilities		548,680	2,106.8	
Engineering(incl.C.M.,H.O.& Fee)		43,894	168.5	
Process Contingency		0	0.0	
Project Contingency		85,926	329.9	
	TOTAL PLANT COST	678,500	2,605.2	
	CASH EXPENDED \$678,500			
	AFUDC	33,925		
	TOTAL PLANT INVESTMENT	712,425	2,735.5	
Royalty Allowance				
Preproduction Costs		18,649	71.6	
Inventory Capital		6,878	26.4	
Initial Catalyst & Chemicals(w/equip.)				
Land Cost		250	1.0	
	TOTAL CAPITAL REQUIREMENT	\$738,202	2,834.5	
<u>OPERATING & MAINTENANCE COSTS(2005)</u>		<u>\$x1000</u>	<u>\$x1000/H2TPD</u>	
Operating Labor		9,935	38.1	
Maintenance Labor		7,464	28.7	
Maintenance Material		11,195	43.0	
Administrative & Support Labor		4,486	17.2	
	TOTAL OPERATION & MAINTENANCE(2005)	\$33,079	127.0	
	FIXED O & M (2005)	\$29,771	114.3	
	VARIABLE O & M (2005)	\$3,308	12.7	
<u>CONSUMABLE OPERATING COSTS, LESS FUEL (2005)</u>		<u>\$x1000</u>	<u>\$/H2TPYr</u>	
Water		781	9.13	
Chemicals		987	11.54	
Other Consumables				
Waste Disposal		1,794	20.97	
	TOTAL CONSUMABLES(2005)	\$3,562	41.64	
<u>BY-PRODUCT CREDITS (2005)</u>				
	Electricity	\$89,369	1,044.60	
	Sulfur	\$3,131	36.60	
<u>FUEL COST(2005)</u>		\$58,174	679.98	
		<u>1ST Year (2009)</u>	<u>Levelized (10th Year)</u>	
<u>PRODUCTION COST SUMMARY</u>		<u>\$/H2TPYr</u>	<u>\$/H2TPYr</u>	
	Fixed O & M	126.18	143.37	
	Variable O & M	14.02	15.93	
	Consumables	45.96	52.22	
	By-product Credit	(1,193.44)	(1,199.51)	
	Fuel	682.70	686.17	
	TOTAL PRODUCTION COST	324.58	-301.82	
<u>LEVELIZED CARRYING CHARGES (Capital)</u>			1,164.86	
		FCR=0.135		
<u>LEVELIZED COST/Ton of H2</u>			863.04	
		Equivalent Lev'd \$/MMBtu	7.063	

Table 4.4.5 E-Gas Plant Hydrogen Production Cost (2 Train Plant)

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY			
TITLE/DEFINITION		2/8/06	
Case:	OPTION: 2 GASIFIER TRAINS (E-Gas Coproduction		
Plant Size:	251.90 (MW,net)	Hydrogen	260.4 Tons/Day
Fuel(type):	Pittsburgh #8	Fuel Cost:	1.61 (\$/MMBtu)
Design/Construction:	4 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	2005	TPI Year:	2007.0 (Jan.)
Capacity Factor:	90.0%		
CAPITAL INVESTMENT		\$x1000	\$x1000/H2TPD
Process Capital & Facilities		523,046	2,008.3
Engineering(incl.C.M.,H.O.&		41,844	160.7
Process Contingency		0	0.0
Project Contingency		82,870	318.2
	TOTAL PLANT COST	647,760	2,487.2
	CASH EXPENDED \$647,760		
	AFUDC	32,388	
	TOTAL PLANT	680,148	2,611.6
Royalty Allowance			
Preproduction Costs		17,933	68.9
Inventory Capital		6,878	26.4
Initial Catalyst &			
Land Cost		250	1.0
	TOTAL CAPITAL	\$705,209	2,707.8
OPERATING & MAINTENANCE COSTS(2005)		\$x1000	\$x1000/H2TPD
Operating Labor		9,935	38.1
Maintenance Labor		7,125	27.4
Maintenance		10,688	41.0
Administrative & Support		4,486	17.2
	TOTAL OPERATION &	\$32,234	123.8
	FIXED O & M (2005)	\$29,011	111.4
	VARIABLE O & M	\$3,223	12.4
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)		\$x1000	\$/H2TPYr
Water		781	9.13
Chemicals		987	11.54
Other Consumables			
Waste Disposal		1,794	20.97
	TOTAL CONSUMABLES(2005)	\$3,562	41.64
BY-PRODUCT CREDITS (2005)			
	Electricity	\$89,369	1,044.60
	Sulfur	\$3,131	36.60
FUEL COST(2005)		\$58,174	679.98
PRODUCTION COST SUMMARY		1ST Year (2009)	Levelized (10th Year)
		\$/H2TPYr	\$/H2TPYr
	Fixed O & M	122.96	139.70
	Variable O & M	13.66	15.52
	Consumables	45.96	52.22
	By-product Credit	(1,193.44)	(1,199.51)
	Fuel	682.70	686.17
	TOTAL PRODUCTION COST -328.16		-305.89
LEVELIZED CARRYING CHARGES (Capital)			1,112.80
LEVELIZED COST/Ton of H2			806.90
Equivalent Lev'd \$/MMBtu			6.604

Table 4.4.6 E-Gas Plant Economic Summary

E-Gas Co-Production Plant Economic Summary (Year 2005 Dollars)

Number of Gasification Equipment Trains	3*	2
Plant Capacity Factor, %	90	90
Net Power Output, MWe	251.9	251.9
Hydrogen Production Rate, lb/hr	21,703	21,703
Total Plant Cost, \$MM	678.5	647.8
Total Plant Investment, \$MM	712.4	680.1
Total Capital Requirement, \$MM	738.2	705.2
1st Year Operating & Maintenance Cost, \$MM	33.1	32.2
1st Year Consumables Cost less Fuel, \$MM	3.6	3.6
1st Year Byproduct Credit, \$MM		
Electricity	89.4	89.4
Sulfur	3.1	3.1
1st Year Fuel Cost, \$MM	58.2	58.2
Levelized Cost of Hydrogen, \$/MMBtu	7.063	6.604

*Includes One Spare Train

5.0 PCFB Gasifier Based Co-Production Plant

5.1 Plant Overview, Performance, and Emissions

Overview

The PCFB based co-production plant is shown in Figure 5.1.1. The plant consists of two sections; the first is dedicated to the production of hydrogen and incorporates a gasification equipment module, whereas, the second section is dedicated to electric power generation and incorporates a conventional CFB boiler. The heart of the gasification equipment module is an oxygen blown, PCFB gasifier that consists of a riser, a recycle cyclone, and a dipleg that returns circulating solids to the base of the riser. From a feeding standpoint the PCFB gasifier is versatile; it operates equally well with a 35 weight percent coal - 65 weight percent water slurry feed, a 75 percent coal - 25 percent water paste feed, or dry feed (in the latter, the coal is pressurized in lock hoppers and blown into the gasifier). Since an investigation to determine the most economical feed arrangement was beyond the scope of this study, and, to assure a consistent comparison of the two plants, it was decided to operate the PCFB gasifier with the same slurry feed, the same oxygen feed, and the same syngas processing arrangement used by the Section 4 entrained flow co-production plant.

Operating at 438.9 psia with a 35 percent coal - 65 percent water slurry, oxygen from a conventional, cryogenic air separation unit, and steam, the PCFB gasifier produces a 1900°F, medium Btu, coal derived syngas and a granular, non sticky char residue. The syngas is cooled to 650°F in a fire-tube type boiler that generates 503°F 700 psia steam. The steam proceeds to the CFB boiler for heating to 1005°F (becomes part of steam turbine reheat steam) and the cooled syngas is then stripped of particulate by a pre-cleaner cyclone and candle filter. After exiting the filter, steam is injected into the syngas to yield a 1.75 steam to CO molar ratio to support downstream water gas shift reactions. The humidified syngas passes through three stages of water gas shift reactors (two high temperature and one low temperature) and gas coolers and the syngas is delivered to a PSA system at 90°F; the PSA separates the hydrogen from the syngas delivering it with a purity of 99.95 percent at a rate of 261 tpd at 355 psig for sale to a near by refinery.

Condensate formed during the cooling of the syngas to 90°F contains contaminants, i.e., HCN, NH₃, HCl, etc. and this “gray water” is sent to a central water treatment system; after cleaning, the water is supplied to the slurry preparation system and the stripping off-gas is sent to the CFB boiler.

The char collected by the cyclone and candle filter and the char drained from the bottom of the gasifier are depressured and transported to the CFB boiler using the PSA vent/purge gas. The char lock hoppers are pressurized with syngas and, when depressuring, they also vent their gases to the CFB boiler.

Figure 5.1.1. PCFB Gasifier Plant Process Block Diagram

The heart of the power producing section of the plant is a conventional CFB boiler consisting of a riser/furnace section, recycle cyclones, diplegs, loop seals, and heat transfer surfaces; it is followed by an air heater, dry scrubber, and baghouse filter and incorporates forced draft and induced draft fans. Crushed coal and the char-PSA vent gas stream from the hydrogen leg of the plant fuel the CFB boiler and limestone is injected to control SO₂ emissions; to control NO_x emissions, the combustion air is admitted to the CFB boiler in stages and ammonia is injected into the flue gas for the selective non-catalytic reduction of NO_x (SNCR). A portion of the limestone, calcined in and drained from the CFB system, provides additional sulfur capture in the spray dryer scrubber. The CFB boiler produces steam for process use and to drive a 307.7 MWe steam turbine. The steam turbine power is sold to the grid to provide a revenue stream that reduces the hydrogen sell price. In the event the gasification leg of the plant should be out of service, the CFB boiler can be operated totally on coal to maintain its full load revenue stream.

Performance

Figures 5.1.2 and 5.1.3 identify the flow rates, pressures, and temperatures of the plant's air/gas flow paths. Tables 5.1.1 and 5.1.2 summarize the plant performance and identify its parasitic power loads; the plant operates with an effective thermal efficiency of 53.0 percent, consumes coal at the total rate of 333,327 lb/hr (70 percent to the PCFB gasifier and 30 percent to the CFB boiler) and produces 261tpd of hydrogen and 255.5 MWe of electricity.

Stream Number	1	2	3	4	5	6	7	8
Stream Location	Coal Pile	Slurry Prep	Slurry Prep	Gasifier	ASU	Gasifier	Gasifier	Gasifier
Temperature, F	59	59	59	250	59	212	633	1900
Pressure, psi	14.7	14.7	14.7	444.9	14.7	454.9	648.5	438.9
Medium	coal	coal	water	slurry	air	O2	steam	mixture
Flow Rate, Klb/hr								
	Gas				638.540	144.080	45.000	468.941
	Solids	333.327	232.600	232.600				45.212
	Liquid			103.775	103.775			
Total Flow, Klb/hr		333.327	232.600	103.775	336.375	638.540	144.080	514.153
Stream Number	9	10	11	12	13	14	15	16
Stream Location	Cooler Outlet	Filter Outlet	HT Shift Inlet	Drains	PSA Inlet	PSA Outlet	PSA Outlet	Gasifier
Temperature, F	650	650	455	90	90	90	90	650
Pressure, psi	435.9	428.4	440.0	379.9	379.9	369.9	20.0	17.0
Medium	mixture	syngas	steam	condensate	syngas	H2	PSA vent	char
Flow Rate, Klb/hr								
	Gas	468.941	468.941	117.559	487.686	21.753	465.934	
	Solids	45.212						11.311
	Liquid			98.814				
Total Flow, Klb/hr		514.153	468.941	117.559	98.814	487.686	21.753	11.311
Stream Number	17	18	19	20	21	22	23	24
Stream Location	CFB Inlet	CFB Inlet	CFB Inlet	CFB Inlet	CFB	Scrubber	Ash Silo	Stack
Temperature, F	148	59	59	59	59	59	148	173
Pressure, psi	17.0	14.7	14.7	14.7	14.7	14.7	14.7	14.7
Medium	mixture	coal	limestone	air	NH3	water	ash	flue gas
Flow Rate, Klb/hr								
	Gas	465.934		2270.000	0.085			2954.750
	Solids	56.515	100.727	64.922			98.544	
	Liquid					95.000		
Total Flow, Klb/hr		522.449	100.727	64.922	2270.000	0.085	95.000	2954.750

Figure 5.1.3 PCFB Gasifier Plant Flow Stream Operating Conditions

Table 5.1.1 PCFB Gasifier Plant Performance Summary

Key Flow Rates Entering Plant, lb/hr		
Coal (As Received)		
To PCFB Gasifier		232,600
To CFB Boiler		100,727
	Total	333,327
Oxygen To PCFB Gasifier		144,080
Limestone To CFB Boiler, lb/hr		64,922
Water, MMgal/day		4.6
Discharges, lb/hr		
Water		10,233
Slag / Ash		98,544
Stack Flue Gas		2,954,750
Gross Steam Turbine Power, Kwe		307,656
Parasitic Power, KWe		52,195
Net Plant Power Output, KWe		255,461
H2 Production Rate, lb/hr		21,753
Plant Performance		
Thermal Input*, Btu/hr		4.150E+09
Equivalent Output**, Btu/hr		
Power		8.719E+08
Hydrogen		1.329E+09
	Total	2.201E+09
Effective Thermal (HHV) Efficiency, %		53.03

*12,450 Btu/lb Pittsburgh 8 at 2.89% sulfur

**Hydrogen at 61,095 Btu/lb and Power at 3,413 Btu/KW

Table 5.1.2 PCFB Gasifier Plant Parasitic Power Losses (KWe)

		Totals*
Coal/Limestone Handling	490	
Gasifier Coal Milling	595	
CFB Coal Crushing	40	
CFB Limestone Crushing**		
Coal Slurry Pumps	215	
		1,340
Air Separation Unit Auxiliaries	15,400	
Oxygen Compressor	7,060	
		22,460
CFB Primary Air Fan	2,865	
CFB Spray Dryer Scrubber	1,100	
CFB Boiler/Scrubber Ash Transport to Silos	400	
CFB Induced Draft Fan	5,720	
CFB Balance	650	
		10,735
Condensate Pump	570	
HP Boiler Feedwater Pump	7,815	
LP Boiler Feedwater Pump	275	
Circulating Water Pump	3,610	
Cooling Tower Fans	2,090	
		14,360
Steam Turbine Auxiliaries	400	
Transformer Losses	900	
		1,300
Miscellaneous Balance-of-Plant	2,000	
		2,000
	Totals	52,195
		52,195

* Totals by Process Area

**Limestone Crushing and Feeding in CFB Balance

Emissions

In the PCFB gasifier based plant all the gases that discharge to the plant stack emanate from the CFB boiler system, hence it controls the plant emissions. To control SO₂ emissions, limestone is injected into the CFB boiler and recycled to a downstream spray dryer scrubber. To control NO_x emissions, combustion air is injected into the CFB boiler in stages and ammonia is injected into its flue gas. To control particulate emissions, a baghouse filter is provided downstream of the scrubber. This same approach to emission control was utilized in the Jacksonville Electric Authority 300 MWe CFB Boiler Demonstration Project [5-1]; when operating with Pittsburgh No 8 coal, that CFB boiler system demonstrated 98.5 percent sulfur capture. This capture efficiency together with the pound per million Btu emission rates observed for NO_x, CO, and particulate were used to establish the co-production plant emissions on a pound per hour basis. Since the CFB boiler heat release is approximately 60 percent of the total plant heat input, these values were then expressed on a total plant heat input basis yielding the values shown in Table 5.1.3.

Table 5.1.3 PCFB Gasifier Plant Emissions

SO ₂		
% Capture		98.5
lb/hr		289
lb/MMBtu		0.070
NO _x		
lb/hr		197
lb/MMBtu		0.048
CO		
lb/hr		45.1
lb/MMBtu		0.011
Particulate		
lb/hr		16.6
lb/MMBtu		0.004

5.2 Process and System Description

The PCFB gasifier based plant consists of numerous systems that work together to produce hydrogen and electricity. For cost estimating purposes those systems have been divided into 14 processing blocks or cost accounts that are identical to those of the entrained flow gasifier based plant. The 14 accounts are presented in Appendix C and, in addition to facilitating cost estimating, these accounts serve as a frame work for a detailed process description of the plant as follows:

Coal, Limestone, and Sand Receiving and Handling

The Pittsburgh No 8 coal is delivered to the site in a 6 inch by zero size; the equipment used to receive, unload, stack, reclaim, crush, and transfer the coal to silos is listed in Account 1. The coal

handling equipment is essentially identical to that of the entrained flow gasifier plant excepting that crushing is to a minus ½ inch size and the transfer conveyor is extended so that it can also supply coal to the CFB boiler silos which are included in Account 7.

Limestone in a 2 inch by zero size is also delivered to the site by train, unloaded by the above equipment, transferred to a separate pile, reclaimed, and transported by the above transfer conveyor to a limestone silo located at the CFB boiler and included in Account 7.

The PCFB gasifier and CFB boiler are started with a bed of sand. The sand is delivered to the site by a pneumatic transport truck that blows the sand into those units before they are started up. Once operating, the sand beds are gradually replaced by a circulating mixture of coal and char (PCFB gasifier) or coal, ash, and limestone (CFB boiler).

Coal-Water Slurry Preparation and Feeding

The PCFB gasifier and CFB boiler operate with two different coal feed systems that withdraw their coal from separate storage silos. The coal stored in the CFB silos is ready for feeding/requires no further processing, whereas, the PCFB gasifier coal must first be milled to a fine size, mixed with water to form a slurry, and pumped into the unit. The slurry preparation, pumping, and heating system used is, with the exception of a difference in capacity and lower gasifier operating pressure (438.9 versus 514.4 psia), identical to that of the entrained flow gasifier plant. Since the PCFB plant utilizes only one gasifier, however, only two trains of coal processing/feeding equipment is required and the 336,375 lb/hr slurry feed rate is about 37 percent less than that of the entrained flow plant.

The coal-water slurry preparation and feeding equipment is listed in Account 2. Slurry preparation equipment consists of two 100 percent capacity trains of day silos, rod mills, and slurry product tanks that operate in parallel, crush minus 1/2 inch coal to a minus 200 mesh size, and mix it with water to form a 35 weight percent coal - 65 weight percent water slurry. From the product tanks the slurry is pumped to two 100 percent capacity feed trains, each connected to the single PCB gasifier and consisting of a slurry storage feed tank, slurry pumps, and slurry heaters. Each feed train normally operates at 50 percent capacity delivering slurry at the rate of 168,188 lb/hr at 250°F.

The coal delivered to the CFB boiler silos requires no further processing and after passing through gravimetric feeders, drag chain conveyors, and isolation valves is gravity fed to the unit via chutes with an air assist.

Oxygen and Nitrogen Supply Systems

The PCFB gasifier oxygen supply system is, excepting for a difference in capacity and pressure, identical to that of the entrained flow gasifier plant. Since the PCFB plant utilizes only one gasifier, its oxygen flow rate is slightly less than half that of the entrained flow plant and only one train of equipment is required. The system incorporates an electrically driven compressor that supplies 210°F 70 psia air to a conventional cryogenic ASU. The ASU includes a liquid oxygen storage tank to guard against short term disruptions and supplies 95 percent pure oxygen at a rate of 144,080 lb/hr to an electrically driven boost compressor. The latter pressurizes the oxygen for delivery to the gasifier at a pressure of 454.9 psia.

The equipment making up the oxygen supply system is listed in Account 4 B.

PCFB Gasifier, Fire-Tube Boiler, and Particulate Removal

The PCFB gasifier together with its fire-tube boiler, pre-cleaner cyclone, candle filter, char depressuring, and char transfer systems are listed under Account 4A. The PCFB gasifier is an approximately 110 foot tall pressure vessel that is refractory lined to a 5 foot inside diameter. Coal is injected at the base of the unit as a coal-water slurry into a bed of 1900°F char. Air and steam enter below the slurry injection point and fluidize the char bed. As these constituents react, a hot syngas is produced which conveys the char vertically up through the vessel/reactor and into a recycle cyclone. Solids contained in the syngas are collected by the recycle cyclone and drain via a dipleg back to the dense bed at the bottom of the PCFB reactor. This recycle loop of hot solids acts as a thermal flywheel and promotes efficient solid-gas reactions.

The 65 per coal - 35 percent water slurry enters the unit at a rate of 336,375 lb/hr at 250°F along with 45,000 lb/hr of 633°F steam and 144,080 lb/hr of 212°F oxygen. Based on these flow rates and, allowing for vessel heat loss, the gasifier operates at 1900°F with a superficial gas velocity of 20 ft/sec and a discharge pressure of 438.9 psia. At these conditions syngas is produced at a rate of 468,941 lb/hr with a hydrogen content of approximately 32 mole percent, a hydrogen to carbon monoxide molar ratio of 1.16, and a steam to carbon monoxide molar ratio of 0.75.

Char is produced at a rate of 56,515 lb/hr along with the syngas and the char continuously circulates through the gasifier until it reaches a density and or size that allow it to escape the recycle cyclone. A nozzle is provided at the bottom of the gasifier to drain/empty bed material at shutdown; the drain is also used intermittently during normal operation to prevent any oversize material from accumulating in the bottom of the bed. The drain nozzle leads to a pressurized water-cooled screw that controls the bottom char/bed withdrawal rate, cools it to 500°F, and discharges to a surge hopper and a lock hopper that depressure the material. A delumper below the lock hopper breaks up any oversize material that may have formed in the unit and a rotary valve feeds the material to a pipeline for transport to the CFB boiler with PSA vent gas.

The PCFB gasifier together with its recycle cyclone, fire-tube boiler, and bottom char cooling and depressuring system is shown in Figure 5.2.1. A surge hopper and lock hopper are also provided under the pre-cleaner cyclone and candle filter to depressure the char they collect. After depressuring the two char streams drain to a common day bin and a rotary valve feeds the material to a pipe line for transport to the CFB boiler with PSA vent gas.

Syngas for Hydrogen Production

After being stripped of all gas entrained particulate in the candle filter, the 650°F syngas undergoes steam injection. The injected steam increases the syngas steam to CO ratio to 1.75 and three stages of water gas shift reactors (two high temperature and one low temperature) with sulfur tolerant catalysts are provided that convert approximately 92 percent of the CO to CO₂ (for a consistent comparison, the PCFB plant utilizes the same sulfur tolerant catalysts, performance, and conversion values as the entrained flow plant water gas shift reactors). Since the water gas shift reaction is exothermic, water-cooled heat exchangers are provided to control the syngas temperature and eventually cool it to 90°F for delivery to the PSA system at a rate of 487,686

lb/hr. During the cooling of the syngas, a condensate is formed that contains some of the gas contaminants i.e. H_2S , NH_3 , etc. This gray water is sent to a steam stripper where the contaminants are driven off, the cleaned water sent to the coal-water slurry preparation system, and the off gas piped to the CFB boiler where it is burned.

The water gas shifting, gas cooling, and condensate equipment are listed in Account 5A-1.

Despite condensation in the upstream gas coolers, some hydrogen sulfide will remain in the cooled syngas (see Table 5.2.1 for syngas compositions at several different plant locations). With the PSA being highly selective, it separates hydrogen from the syngas to a purity of 99.95 percent and delivers it at a rate of 21,753 lb/hr at 370 psia for transport to the near by refinery. The gas that vents from the PSA exits at 20 psia and is used to convey the char collected by the filter, pre-cleaner cyclone, and bed drain system to the CFB boiler. Since the vent gas is burned in the CFB boiler system, where all plant emission control takes place, the plant does not require an acid gas removal system.

The PSA system appears under Account 5B-1 and, producing the same amount of hydrogen, is essentially identical to that of the entrained flow plant.

The composition of the syngas entering and exiting the hydrogen production equipment train, as well as interior points, is presented in Table 5.2.1.

CFB Boiler

Coal, char, PSA vent gas, and gray water off-gas are burned in the CFB boiler with hot air delivered by forced draft and induced draft fans. The solids and gases contain sulfur and nitrogen which, during their combustion at 1600°F , can form SO_2 and NO_x . To control SO_2 emissions, limestone is fed to the CFB boiler and, to minimize NO_x emissions, the air is introduced in stages and SNCR employed. The solids and air enter at the base of the unit, form a relatively dense fluidized bed of coal, char, ash, and limestone, and the resulting flue gas, together with entrained particulate, flow vertically up the unit. At the top, recycle cyclones clean the gas of coarse particulate and return them to the base of the unit via bubbling fluidized bed heat exchangers and pressure seals to establish a circulating bed of hot solids.

Figure 5.2.1 PCFB Gasifier Arrangement

Table 5.2.1 PCFB Gasifier Syngas Compositions

Location	Filter Exit	Inlet of HT Shifter	Outlet of LT Shifter	PSA Inlet
Gas				
Temperature, F	650	587	419	90
Pressure, psia	428.4	427.4	389.9	379.9
Gas Composition, mole fraction				
AR	0.0079	0.0062	0.0062	0.0076
CH ₄	0.0332	0.0260	0.0260	0.0318
CO	0.2744	0.2152	0.0211	0.0258
CO ₂	0.1481	0.1161	0.3101	0.3788
H ₂	0.3188	0.2500	0.4440	0.5424
H ₂ O	0.2049	0.3765	0.1825	0.0016
H ₂ S	0.0077	0.0060	0.0060	0.0074
N ₂	0.0048	0.0037	0.0037	0.0046
NH ₃	0.0003	0.0002	0.0002	0.0001
Total	1.0000	1.0000	1.0000	1.0000
Gas Molecular Weight	19.79	19.40	19.40	19.71

A forced draft fan supplies air to a tubular air heater at a rate of 2,270,000 lb/hr where it is heated by hot exhaust flue gas to 543°F for delivery to the CFB boiler. In addition to the air, the major flow streams entering the CFB boiler are coal, char, limestone, and PSA vent gas at rates of 100,727 lb/hr, 56,515 lb/hr, 64,922 lb/hr, and 465,934 lb/hr respectively; the CFB boiler combusts the fuels at 1600°F and their heat release is used to generate, superheat, and reheat steam to 1005°F. The 2400 psig 1005°F superheated steam is generated at a rate of 1,790,000 lb/hr, whereas, the 569 psig 1005°F reheat steam is provided at a rate of 1,848,000 lb/hr. The reheat steam flow rate is slightly higher than the superheat flow rate because of the steam (cold reheat) generated by the PCFB gasifier fire-tube boiler. The distribution of the CFB boiler heat release is 51 percent from coal, 18 percent from char, and 31 percent from PSA vent gas. The CFB boiler operates with a combustion efficiency of 98 percent, a value typical of a conventional CFB boiler. In combusting the coal and char with limestone, an ash residue containing spent limestone is generated at the rate of 98,544 lb/hr for ultimate transfer to silos for disposal.

The CFB boiler is shown in Figures 5.2.2 and 5.2.3 together with its fuel and limestone silos. In plan view the assembly possesses a footprint approximately 160 foot wide by 220 foot long and the boiler consists of a single, water-cooled furnace, three steam cooled recycle cyclones, three Integrated Recycle Heat Exchangers (INTREXsTM), and a parallel pass convective heat recovery section followed by an economizer and tubular air heater. The furnace is a gas tight enclosure formed from membrane tube panels that are cooled by the natural circulation of water from the

steam drum. Water-cooled, partial division walls divide the furnace into three zones that help to evenly distribute gas and solids to the three recycle cyclone separators. Six furnace wing walls provide additional evaporative tube surface. To avoid erosion from circulating solids (coal, limestone, char, and ash) a thin refractory lining is applied over metal studs in the lower portion of the furnace and around the openings to the cyclones.

The three steam cooled cyclones are formed from membrane walls that are also protected from erosion by a 1 inch thick refractory lining. The hot solids collected by the cyclones pass through pressure seals and drain to the INTREX bubbling fluidized beds located beneath them and containing intermediate and finishing superheater tube bundles. These beds cool the solids for return to the furnace for reheating to 1600°F. During start-up the cooling beds are bypassed and solids returned directly to the furnace.

The three cyclones discharge their ~1600°F gas to a plenum that leads to two parallel gas paths. Each path contains convective tube bundles; one contains all reheat tube surfaces, the other contains primary superheat tube surface. Dampers located at the outlet of each path proportion the gas flow over their tube surfaces and enable reheat steam temperatures to be controlled without the need for water spray. The gas streams from the two paths combine for further cooling by convective economizer tube bundles and then discharge to a tubular air heater. The latter cools the flue gas from 641°F to 300°F and in doing so preheats the CFB combustion air to 543°F.

After exiting the CFB boiler at 300°F, the flue gas enters an SO₂ polishing scrubber, exits at approximately 150°F, proceeds to a bag house filter and induced draft fan, and discharges to the stack at 173°F. The assembly is shown in Figure 5.2.4 and in plan view it possesses a footprint approximately 125 foot wide by 330 foot long. The scrubber is a semi-dry/spray dryer type unit that operates with processed CFB ash and slurry water and, together with the CFB boiler, enables the plant to operate with an overall sulfur capture efficiency of 98.5 percent. The CFB boiler bed/bottom ash is cooled to 500°F via stripper coolers. A portion of that ash is crushed, mixed with ash captured by the bag house filter, slaked, slurried with water, and injected into the spray dryer to serve as its sulfur capturing sorbent; if necessary the recycled ash can be supplemented with a small amount of fresh lime.

Figure 5.2.2 CFB Boiler Side View

The CFB boiler together with its silos, feeders, fans, ash coolers, SNCR, air heater, spray dryer scrubber, bag house filter, structural steel, stack, and SNCR unloading, storage, and injection equipment are listed in Account 7.

Steam Turbine Generator

The steam turbine consists of tandem high pressure (HP), intermediate pressure (IP), and double flow low pressure (LP) turbine sections connected via a common shaft that drives a 3,600 RPM hydrogen-cooled generator. The turbine operates with 2400 psig 1000°F 1,790,000 lb/hr throttle conditions, a single stage of reheat to 1000°F, and 4 stages of steam extraction. The generator is a synchronous type that operates with an efficiency of 98 percent for a net output of 307.7 MWe.

A single pass, horizontal type condenser is provided under the steam turbine to condense the steam turbine exhaust at a rate of 1,490,000 lb/hr at 1 psia pressure.

The steam turbine and its auxiliaries are listed in Account 8.

Condensate and Feedwater Systems

In the condenser the steam is indirectly cooled by circulating water that proceeds to a mechanical draft, evaporative cooling tower. The cooling tower consists of multiple cells that are operated as required to meet the plant cooling load; the cooling tower and circulating water pumps are listed under Account 9.

The condensate and feedwater equipment required by the plant are listed under Account 3. The plant steam cycle is typical of a modern power generating plant; it employs a highly efficient regenerative feedwater heating system complete with pumps, deaerator, and 4 stages of feedwater heaters that deliver 491°F, 3010 psig feedwater to the CFB boiler economizer at a rate of 1,709,000 lb/hr. Where the cycle differs from a conventional unit is that it also delivers low pressure feedwater and steam to the gasification leg of the plant where the major users are:

- 1.) the PCFB gasifier fire-tube boiler---using 329°F feedwater, the fire-tube boiler cools the syngas from 1900°F to 650°F and in doing so generates 503°F 685 psig saturated steam at a rate of 316,000 lb/hr; approximately 1/3rd of this steam is injected into the syngas for water gas shifting and the balance returns to the steam cycle.
- 2.) the PCFB gasifier----633F, 634 psig steam is injected into the gasifier at a rate of 45,000 lb/hr to support steam carbon reactions.

Two 50 percent capacity motor driven pumps extract condensate from the condenser hot well and pump it through a feedwater heater and economizer and on to the deaerator. Two 50 percent capacity motor driven boiler feed pumps in turn pump the water through three additional stages of feedwater heaters, the CFB high pressure economizer, and deliver it to the CFB steam drum.

5.3 List of Plant Major Equipment

The major pieces of equipment required by the PCFB gasifier based plant have been divided into the 14 accounts listed in Appendix C; those accounts are the basis for the plant costs presented in Section 5.4 and are identical to those of the entrained flow gasifier plant.

5.4 Plant Costs and Economic Analysis

The PCFB gasifier based co-production plant has been designed to produce the same amount of electricity and the same amount of hydrogen as the entrained flow gasifier plant. In addition, the PCFB gasifier based plant has been designed to use, wherever possible, similar gas processing equipment and similar balance of plant systems so that the differences between the two gasification technologies can be clearly seen. Aside from the PCFB gasifier and CFB boiler systems, which appear in Accounts 4 and 7, the two plants are similar and, as discussed in Section 3.5, the E-Gas based plant cost estimate was the starting point for the determination of the PCFB gasifier based plant costs. Starting with the former's cost estimate, Parsons modified its costs on an account by account basis to reflect changes to the PCFB gasifier based plant. As part of this effort FW provided Parsons with the arrangement, sizes and costs of the following equipment:

PCFB Gasifier Scope of Supply (Account 4)

Gasifier (riser, recycle cyclone, dipleg, and start up burners)

Fire-tube boiler with drum and piping

Gasifier to fire-tube boiler refractory lined piping

Bed drain char system (screw cooler, surge hopper, lock hopper, valving, delumper, and rotary valve)

Filter and pre-cleaner cyclone char system (surge hoppers, lock hoppers, valving, day bin, and rotary valves)

Instrumentation

CFB Boiler Scope of Supply (Account 7)

Boiler (riser, recycle cyclones, diplegs, INTREXs, heat recovery area, and start up burners)

Coal feed (silos, chutes, and feeders)

Limestone feed (silo, crushers, chutes, and feeders)

Bottom ash system (stripper coolers and rotary valves)

Air supply system (air ducting and Primary, Secondary, and ID fans)

Air heater

SNCR system (rail unloading, tanks, pumps, vaporizers, piping, and distribution system)

SO₂ spray dryer scrubber system including bag house filter and flue gas ducting

Structural steel

Instrumentation

Using the size, arrangement, and cost data supplied by FW, Parsons estimated the cost of installing/erecting the above equipment together with the supply and erection of all other equipment required by the plant.

Tables 5.4.1 through 5.4.4 present the costs and economics determined by Parsons for the PCFB gasifier based co-production plant. Table 5.4.1 presents the costs of the plant at the account

summary level and the reader is referred to Appendix C for sub-account values. Tables 5.4.2 and 5.4.3 present operating and consumable requirements and costs, respectively, and Table 5.4.4 calculates the plant 10 year levelized hydrogen production cost. Although the ash from the CFB boiler can potentially be used for road construction, structural fill, agricultural fertilizing, etc. the economics of such uses are highly site dependent and no credit was taken for this potential ash sale. In contrast, the electricity produced by the plant is assumed to be sold to the grid at a price of \$45/MWhr and, based on a plant capacity factor of 90 per cent, its sale provides a revenue stream of \$90.8 million/yr. As seen in these tables the PCFB gasifier based plant has a total plant cost in year 2005 dollars of \$625.4 million and, allowing for a general inflation rate of 2.5 percent per year and coal cost escalating at only 0.1 percent per year, a 10 year levelized cost of hydrogen of \$6.75/MMBtu. An increase in the electricity sell price will increase the plant revenues and allow the hydrogen to be sold at a lower price while still recovering all costs and maintaining the desired return on equity; as shown in Figure 5.4.1, an increase in the electricity sell price to \$50 MW/hr would allow the hydrogen sell price to be reduced to \$5.68/MMBtu.

Table 5.4.1 PCFB Plant TPC in Thousands of Year 2005 Dollars

Account #	Account Title	
1	Coal & Sorbent Handling	29,566
2	Coal-Water Slurry Prep & Feed	30,086
3	Feedwater & Misc BOP Systems	24,436
4	Gasifier & Accessories	112,991
5	H ₂ Separation, Gas Cleanup, & Piping	44,484
6	Combustion Turbine & Accessories	
7	CFB Boiler System, Ducting, & Stack	168,842
8	Steam Turbine Generator	64,738
9	Cooling Water System	20,883
10	Slag/Ash Handling Systems	10,835
11	Accessory Electric Plant	52,188
12	Instrumentation & Control	24,447
13	Improvements to Site	10,720
14	Buildings & Structures	31,197
	Total	625,413

Table 5.4.2 PCFB Plant Capital and Operating Requirements

OPERATING REQUIREMENTS				
			WMM	1/21/06
H2 & Electric Coproduction -Foster Wheeler Partial Gasification Module				
Operating Labor Rate(base)	\$28.00	per hour		
Operating Labor Burden	35%	of base		
Labor Overhead Charge Rate	30%	of base		
Operating Labor Hours per Year	1,944			
Administrative & Support Labor	45.15%	of Operating Labor		
Operating Labor Requirements (OJ) per Shift - 4 Shifts				
Category	1 Unit per Mod		Total Plant	
Skilled Operator	3		3	
Operator	18		18	
Foreman	3		3	
Lab Techs, etc	2		2	
Total OJs	26		26	
CONSUMABLES				
H2 & Electric Coproduction -Foster Wheeler Partial Gasification Module				
	Consumption		Unit	
	Initial	Per Day	Cost	
Water (per 1,000gals)	N/A	4,636	\$0.82	
Chemicals				
Water Treatment (lbs)	336,685	11,223	\$0.20	
Limestone (Tons)	23,372	779	\$18.00	
COS Catalyst (CuFt)	0	0.00	\$575.00	
Shift Catalyst (CuFt)	237	0.65	\$450.00	
Claus Catalyst (CuFt)	0	0.00	\$325.00	
Hdrogenation Catalyst (CuFt)	0	0.00	\$290.00	
Amine (lbs)	0	0	\$1.09	
Ammonia (lbs)	61,200	2,040	\$0.22	
Other				
Supplemental Fuel (Mmbtu)	N/A	0	\$15.00	
Waste Disposal				
Ash (Tons)	N/A	1,183	\$12.00	
Slag (Tons)	N/A	0	\$12.00	
BYPRODUCTS				
Sulfur (Tons)	N/A	0	\$75.00	
Excess Electric Generation (MWh)	N/A	6,141	\$45.00	
FUEL				
Fuel (Tons)	59,999	4,000	\$40.00	

Table 5.4.3 PCFB Plant Operating and Consumables Costs

Operation, Maintenance, and Supplies Cost						
Case: H2 & Electric Coproduction -Foster Wheeler PCFB Gasifier						
Plant Size: 255.86 MW, net Jan 2005 Dollars						
261.0 H2 Tons / Day 1/21/06						
Item / Description	Qty	Qty	Qty	Qty	Qty	\$ x 1000
Operating Labor	26	4	\$54,432	1.35	1.30	\$9,935
# operators/shift x # shifts x \$/year x Benefits x Overhead						
Maintenance Labor	0.4	\$625,414	2.3500%			\$5,879
%of Cap Cost X \$Cap Cost x 1000 X Maint %						
Maintenance Materials	0.6	\$625,414	2.3500%			\$8,818
%of Cap Cost X \$Cap Cost x 1000 X Maint %						
Administrative & Support Labor	45.2%	\$9,934,929				\$4,486
% X Operating Labor						
CONSUMABLES - 1st Year						
Water	4.636	365	90%	\$815		\$1,241
mgd x Day/yr x CF x \$/mgd						
Chemicals						
Water Treatment	11,223	\$0.20	365	90%		\$737
lbs/day x \$/lb x Days/Yr x CF						
Limestone	779	\$18.00	90%			\$4,607
Tons/dav x \$/Ton x 365 x CF						
Catalysts-Several	0.65	\$450	90%			\$96
CuFt/day x \$/CuFt x 365 x CF						
Amine	0	\$1.09	90%			\$0
lbs/day x \$/lb x Days/Yr x CF						
Ammonia	2,040	\$0.22	90%			\$147
lbs/day x \$/lb x Days/Yr x CF						
Subtotals						\$5,587
Other .						
#REF!	0	\$1.50	90%			\$0
MMBTU/day x \$/MMbtu x 365Days/Yr x CF						
Gases	0	\$0.35	90%			\$0
cuft/day x \$/cuft x 365Days/Yr x CF						
Subtotals						\$0
Waste Disposal						
Ash	1,183	\$12.00	90%			\$4,662
Tons/dav x \$/Ton x 365 x CF						
Slag	0	\$12.00	90%			\$0
Tons/day x \$/Ton x 365 x CF						
Subtotals						\$4,662
Totals						6,050

Table 5.4.4 PCFB Plant Hydrogen Production Cost

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY			
TITLE/DEFINITION			1/21/06
Case:	H2 & Electric Coproduction -Foster Wheeler PCFB Gasifier		
Plant Size:	255.86 (MW,net)	H2	261.0 Tons/Day
Fuel(type):	Pittsburgh #8	Fuel Cost:	1.61 (\$/MMBtu)
Design/Construction:	4 (years)	BookLife:	20 (years)
TPC(Plant Cost) Year:	2005	TPI Year:	2007.0 (Jan.)
Capacity Factor:	90.0%		
CAPITAL INVESTMENT		\$x1000	\$x1000/H2TPY
Process Capital & Facilities		499,646	1,914.1
Engineering(incl.C.M.,H.O.& Fee)		39,972	153.1
Process Contingency		6,291	24.1
Project Contingency		79,505	304.6
TOTAL PLANT COST		625,414	2,395.9
TOTAL CASH EXPENDED	\$625,414		
AFUDC		31,271	
TOTAL PLANT INVESTMENT		656,684	2,515.7
Royalty Allowance			
Preproduction Costs		17,734	67.9
Inventory Capital		6,785	26.0
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		250	1.0
TOTAL CAPITAL REQUIREMENT	\$681,453		2,610.6
OPERATING & MAINTENANCE COSTS(2005)		\$x1000	\$x1000/H2TPY
Operating Labor		9,935	38.1
Maintenance Labor		5,879	22.5
Maintenance Material		8,818	33.8
Administrative & Support Labor		4,486	17.2
TOTAL OPERATION & MAINTENANCE	\$29,118		111.5
FIXED O & M (2005)	\$26,206		100.4
VARIABLE O & M (2005)	\$2,912		11.2
CONSUMABLE OPERATING COSTS, LESS FUEL(2005)		\$x1000	\$/H2TPY
Water		1,241	14.47
Chemicals		5,587	65.16
Other Consumables			
Waste Disposal		4,662	54.36
TOTAL CONSUMABLES(2005)	\$11,490		133.99
BY-PRODUCT CREDITS (2005)			
Electricity		\$90,774	1,058.58
Sulfur		\$0	0.00
FUEL COST(2005)		\$52,559	612.93
PRODUCTION COST SUMMARY		1ST Year (2009)	Levelized (10th Year)
		\$/H2TPYr	\$/H2TPYr
Fixed O & M		110.81	125.91
Variable O & M		12.31	13.99
Consumables		147.90	168.05
By-product Credit		(1,168.48)	(1,174.42)
Fuel		615.39	618.51
TOTAL PRODUCTION COST		282.06	-247.96
LEVELIZED CARRYING CHARGES (Capital)			1,072.84
	FCR=0.135		
LEVELIZED COST/Ton of H2			824.88
	Equivalent Lev'd \$/MMBtu		6.751

Figure 5.4.1 Effect of Electricity Sell Price on PCFB Plant Hydrogen Sell Price

6.0 Hydrogen Production by Steam Methane Reforming (SMR)

Hydrogen is widely produced by the steam reforming of light hydrocarbons. In this process a mixture of desulfurized natural gas and steam is typically passed over a nickel based catalyst at approximately 1500°F and 500 psig. The steam is supplied at roughly a 3 to 5 steam-to-carbon molar feed ratio and approximately 70 percent of the hydrocarbon is converted to oxides of carbon. Upon exiting the high alloy reformer tubes that contain the catalyst, the gas is cooled, water gas shifted, and passed through cycling PSA vessels to separate hydrogen. The vent gas/purge gas from the PSA together with supplemented natural gas is then burned to provide the heat needed by the reforming process. Figure 6.1 is a simplified process block diagram of the SMR process and Figure 6.2, extracted from a December 2004 report [6-1], presents the sell price of hydrogen produced from natural gas.

According to [6-1] the US Energy Information Agency is forecasting that natural gas prices will be in the \$4.50 to \$5.00/MMBtu range by 2025. In January 2005 the spot natural gas price at the Henry Hub was approximately \$6.00/MMBtu and it peaked at about \$15.00/MMBtu in September 2005. Based on Figure 6.2 and Table 5.4.4, hydrogen produced by the coal-fueled PCFB gasifier co-production plant will be competitive with SMR produced hydrogen at a natural gas price of approximately \$4/MMBtu.

Figure 6.1 Natural Gas Steam Reforming Process Block Diagram

Figure 6.2 Cost of Hydrogen Produced from Steam Methane Reforming

7.0 Results and Discussion/Plant Comparisons

7.1 Redundancy and Plant Availability

The gasifiers used by the two co-production plants studied herein represent new technologies that can affect plant availability. Both plants utilize similar systems to feed coal to their gasifiers, cool their syngas, remove gas entrained particulate, water gas shift their gases, and separate their hydrogen. Although there are some differences in solids removal systems (slag bath depressuring versus dry char depressuring) and turbine availabilities (gas turbine versus steam turbine), it is expected that the type of gasification systems employed will control the ultimate plant availability.

The high temperatures of entrained flow gasifiers (~2500°F) create severe operating conditions included in which are a molten slag that can corrode refractory linings and a sticky ash that can foul down stream equipment. According to [7-1], thermocouples in the gasification zone last 30-45 days, burners last 2-6 months, and refractory linings on the order of 6-18 months. During the 1994 to 1997 time period four coal fueled, power producing IGCC demonstration plants started up (Buggenum, Wabash, Polk County, and Puertollano). Each had a single, high temperature, entrained flow gasifier supplied by a different manufacturer. Despite several years of operation, modifications, and improvements, the availability of these units, when fueled with coal, remains disappointingly low and there is a growing consensus that future plants will require at least a spare gasifier, if not a spare gasification equipment train, to achieve high availability [2-1], [2-2], [7-2], [7-3].

The PCFB gasifier operating temperature, in contrast, is set below the coal ash fusion temperature. As a result, it does not produce molten slag or sticky ash and it should be immune to many of the above problems. This is the same philosophy used in commercial CFB boilers which exhibit availabilities in excess of 90 percent [7-4] and a value of 95 percent is reported in [7-5]. Based on commercial scale CFB combustion and pilot scale CFB gasification experience, FW believes the relatively low operating temperature of the PCFB gasifier will eliminate the above entrained flow gasifier problems. As a result, FW believes PCFB gasifier availability will be comparable to that of its CFB boilers and its co-production plant will not require a spare gasifier.

The availabilities ultimately achievable by mature high temperature entrained flow versus low temperature circulating fluidized bed gasifiers, however, are subject to debate. As a result economic data has been presented for the entrained flow gasifier plant both with and without a spare gasifier equipment train.

7.2 Overall Plant Arrangement

The PCFB gasifier and the entrained flow gasifier co-production plants are similar in arrangement in that each utilizes two trains of equipment that operate in parallel; the first equipment train produces a coal derived syngas which, after processing and through the use of PSA technology, yields 99.95 percent pure, 355 psig hydrogen for sale to a refinery. The second equipment train produces electricity that is sold to the grid to provide a revenue stream that defrays the cost of hydrogen production. Although the functions of the two equipment trains are similar, they

incorporate differing components and differing processes, which, ultimately result in different plant performance and costs.

Although both plants incorporate an oxygen blown, coal-water slurry fed gasifier to produce syngas for hydrogen production, the PCFB plant gasifier operates at a lower temperature and char fines, captured by the candle filter and pre-cleaner cyclone, are not recycled back to it; as a result, the PCFB gasifier operates with only 80.4 per cent carbon conversion efficiency. The char residue, however, is not wasted as it is burned in a CFB boiler along with coal and the vent/purge gas from the PSA to produce steam to drive a steam turbine for electric power generation. The CFB boiler utilizes limestone feed, staged air injection, ammonia injection, and a dry scrubber to control SO₂ and NO_x emissions and serves as the emission control device for the plant. It is also used to flare the gasifier syngas at start-up and shut-down.

The entrained flow plant gasifier is a two stage unit that operates at a much higher temperature (1st stage estimated to be ~2500°F) and it converts its entire coal feed into a syngas and a molten ash slag waste. Since there is no char residue left for power production, an identical gasifier must be provided to produce syngas for conventional gas turbine-steam turbine combined cycle power generation. With no CFB boiler available to control the plant emissions, the entrained flow plant utilizes syngas amine washing for sulfur capture, a Claus Plant for sulfur recovery, and a separate boiler to burn its low pressure, low Btu PSA vent gas.

In summary, the PCFB plant has one gasifier, one CFB boiler, and one large steam turbine, whereas, the entrained flow plant has two gasifiers, two acid gas removal systems, an H₂S gas concentrator, one Claus Plant, one gas turbine, and two smaller steam turbines.

Although the preparation of arrangement drawings was beyond the scope of this study, some insight can be gained into the physical arrangement of the two plants from Figure 7.2.1. This figure, extracted from one of Parsons' previous studies [7-6], depicts a two train, E-Gas based, IGCC plant that fuels two GE 7FA gas turbines for combined cycle power generation. Based on the line scale shown in this drawing, each gasification block occupies about a 92,00 ft² footprint with its gasifier equipment train (slurry storage tanks through candle filter) occupying approximately 54,000 ft² of this area. Noting that the entrained flow plant gasifier block area is about 25 percent larger than that of the CFB boiler system, it safely represents a CFB boiler system footprint. Table 7.2.1 presents a qualitative comparison of the two co-production plant arrangements and it indicates that the PCFB gasifier based co-production plant should require less land, especially when a third/spare train of gasifier equipment is added to the plant. Since no co-production plant drawings were prepared to quantify the Table 7.1.1 comparison, the footprint advantage of the PCFB plant, which would also lead to lower structural steel, wiring, piping, site preparation work, etc. costs, was ignored in the cost and economic evaluations.

Table 7.2.1 Comparison of Co-Production Plant Foot Prints (See Figure 7.2.1)

Co-Production Plant	PCFB Gasifier Based	E-Gas Based
Right Hand Gasifier Block	Replace with CFB System	Keep Unchanged
7FA Gas Turbines	Eliminate Both	Keep One
Steam Turbine Building	Similar	Similar
Cooling Towers	Keep Unchanged	Reduce by 50 %
ASU	Reduce by 50 %	Keep Unchanged
Acid Gas and Sulfur Recovery	Eliminate All	Keep Unchanged
H ₂ S Gas Concentrator System	Not Required	Add
Waste Water Treatment	Reduce in Size	Keep Unchanged
Spare Gasifier Train (~54,000 FT ²)	Not Required	Add
Slurry Prep	Reduce in Size	Keep Unchanged

7.3 Plant Performance

The differences between the two plants are ultimately attributed to the gasification technology they employ. The entrained flow plant uses a high temperature, high carbon conversion gasifier that necessitates cold gas cleanup and combined cycle power generation. The PCFB plant uses a lower temperature, lower carbon conversion gasifier which necessitates use of a CFB boiler for char combustion and a steam turbine for power generation. Although the gasification technologies are different, both plants require oxygen, syngas cooling, syngas particulate removal, water gas shifting, and PSA technology. To permit a consistent comparison, the PCFB gasifier plant has been designed to use the same slurry feed and oxygen supply systems as well as the same syngas processing components with the latter operating at similar temperatures.

Table 7.3.1 compares the performance of the two plants. With both plants designed to produce the same amount of hydrogen and electricity, the effective thermal efficiency of the PCFB gasifier based co-production plant is 5.4 percentage points higher than the entrained flow plant (53.0 versus 47.6 percent).

Some of the factors that enable the PCFB gasifier plant to operate with a higher effective thermal efficiency are that it:

- 1.) uses less process steam
- 2.) condenses less steam from its syngas
- 3.) requires less parasitic power
- 4.) has a lower stack energy loss
- 5.) utilizes a more efficient steam cycle/steam turbine

The gas turbine and cold gas clean-up/acid gas removal system used by the entrained flow plant contribute to its lower efficiency. With the gas turbine fueled with syngas, the entrained flow plant syngas production rate is 69 percent higher than the PCFB plant. This gas undergoes acid gas removal by amine solvent and 141,182 lb/hr of steam is diverted from the plant steam cycle for its regeneration. Since the syngas is cooled to approximately 100°F for delivery to the acid gas system, steam is condensed during the cooling of the syngas and, with the heat of condensation being transferred to low temperature cooling water, much of it is at too low of a temperature to be used efficiently by the steam cycle. Although the PCFB gasifier plant also cools its syngas to a similar temperature (a requirement of the PSA system), its syngas flow rate is lower and, hence, its condensation loss is lower. Similarly, the PCFB plant slurry and oxygen production rates are lower with the former requiring less steam to be extracted from the steam cycle for slurry heating and the latter leading to lower ASU and oxygen compression power losses. The entrained flow gasifier plant's higher parasitic power draw is further exacerbated by the use of nitrogen to control gas turbine NO_x emissions (nitrogen compression requires 24.5 MWe of power). On an overall basis the parasitic power draw of the entrained flow plant is approximately 42 MWe higher than the PCFB gasifier plant and, as seen from Table 7.3.2, the ASU and oxygen and nitrogen compression systems are major causes of this disadvantage. The gas turbine operates at a much higher excess air level than the CFB boiler and, as a result, the entrained flow plant, with a 79 percent higher stack gas flow rate, has a higher stack gas energy loss.

Table 7.3.1 Comparison of Co-Production Plant Overall Performance

Type of Gasifier	E-Gas Entrained Flow	FW PCFB
Key Flow Rates Entering Plant, lb/hr		
Coal (As Received)		
To Gasifier # 1	184,469	232,600
To Gasifier # 2	184,469	
To CFB Boiler		100,727
Total	368,938	333,327
Oxygen		
To Gasifier # 1	145,923	144,080
To Gasifier # 2	145,923	
To Claus Plant	4,995	
Total	296,841	144,080
Limestone, lb/hr		64,922
Water, MMgal/day	2.9	4.6
Discharges, lb/hr		
Water	36,653	10,233
Slag / Ash	37,934	98,544
Sulfur	10,608	
Stack Flue Gas	5,270,485	2,954,750
Gross Power, KWe		
7 FA Gas Turbine	197,000	
Steam Turbine	149,020	307,656
Total	346,020	307,656
Parasitic Power, KWe	94,120	52,195
Net Plant Power Output, kWe	251,900	255,461
H2 Production Rate, lb/hr	21,703	21,753
Plant Performance		
Thermal Input*, Btu/hr	4.593E+09	4.150E+09
Equivalent Output**, Btu/hr		
Power	8.595E+08	8.719E+08
Hydrogen	1.326E+09	1.329E+09
Total	2.185E+09	2.201E+09
Effective Thermal (HHV) Efficiency, %	47.58	53.03

*12,450 Btu/lb Pittsburgh 8 at 2.89% sulfur

**Hydrogen at 61,095 Btu/lb and Power at 3,413 Btu/KW

Table 7.3.2 Comparison of Co-Production Plant Parasitic Power (KWe)

Type of Gasifier	----E-Gas Entrained Flow----		-----FW PCFB-----	
	Process Areas	Totals	Process Areas	Totals
Solids Handling/Crushing/Pumping	2,180	2,180	1,340	1,340
Air Separation Unit Auxiliaries	31,200		15,400	
Oxygen Compressors	17,160		7,060	
Nitrogen Compressor	24,500			
		72,860		22,460
Fines and Claus Recycle	4,340			
Amine & Claus Auxiliaries	2,340			
Fired Boiler Air Fan	1,250			
CFB Fans and Dry Scrubber			10,735	
		7,930		10,735
Condensate and Boiler Feed Pumps	2,740		8,660	
Circ Water and Cooling Tower	3,380		5,700	
		6,120		14,360
Miscellaneous	5,030	5,030	3,300	3,300
Totals	94,120	94,120	52,195	52,195

With the PCFB gasifier plant operating at a higher efficiency, the entrained flow plant requires an additional 443 MM Btu/hr of heat input to produce the same amount of hydrogen and electricity. Table 7.3.3 attempts to quantify/identify how much each of the above factors/differences contribute to the entrained flow plant need for additional energy. Since steam condensations are occurring at a variety of process conditions, for simplicity sake, the condensation loss has been estimated assuming a 950 Btu/lb heat of condensation. Table 7.3.3 reveals that syngas steam condensation is the dominant loss, being almost double that of the next larger component, parasitic power. Hence, even if the PCFB plant parasitic power were increased to match that of the entrained flow, possibly by converting the CFB boiler to oxy-firing to facilitate CO₂ sequestration, the PCFB gasifier plant would still be more efficient.

Table 7.3.3 Comparison of Co-Production Plant Energy Losses

Type of Gasifier	Entrained Flow	PCFB	-----Entrained Flow Plant Greater By-----	
Process Steam, lb/hr				
Condensed from Syngas				
H2 Train	110,856	98,814		
Power Train	30,326			
To Amine Reboilers				
Reboiler # 1	90,919			
Reboiler # 2	50,293			
To Sour Water Stripper	39,461	19,069		
To Waste Water Treatment	64,352			
Total	386,207	117,883	268,324 lb/hr at say 950 Btu/lb	255 MM Btu/hr
Parasitic Power Consumption, KWe	94,120	51,797	42,323 KWe at 3,413 Btu/KWe	144 MM Btu/hr
Stack Gas Flow Rate, lb/hr	5,270,485	2,954,270	2,316,215 lb/hr at say cp of 0.214 Btu/lb and 200F delta T	99 MM Btu/hr
				498 MM Btu/hr

The higher efficiency of the PCFB gasifier plant leads to lower consumables. The PCFB gasifier plant operates with 9 percent less coal, 51 percent less oxygen, and 44 percent less stack gas. Although the PCFB based plant does not require amine and nitrogen for SO₂ and NO_x control, its use of limestone for SO₂ control results in a solid waste flow rate approximately double that of the entrained flow plant, e.g., 98,544 versus 48,524 lbs/hr.

7.4 Plant Emissions

The stack emissions of the two plants are presented on pound per hour and pound per million Btu of total plant heat input bases in Table 7.4.1. In the PCFB gasifier based plant the CFB boiler system controls the plant emissions; its pound per hour values were calculated using the pound per million Btu emission rates measured with Pittsburgh No 8 coal in the Jacksonville Electric Authority 300 MWe CFB Boiler Demonstration Project [5-1]. Since the CFB boiler heat release is approximately 60 percent of the total plant heat input, these values were then expressed on a total plant heat input basis yielding the values shown.

The emissions of the entrained flow plant are the total of those contained in the exhaust from its 7FA gas turbine and its PSA vent gas fired boiler. The Wabash IGCC Demonstration Plant, which incorporated an E-Gas gasifier, an amine scrubber for sulfur capture, a Claus Plant for sulfur recovery, and a GE 7FA gas turbine, operated with SO₂ and NO_x emissions rates of 0.13 and 0.08 lb/MMBtu respectively [4-1]. To reduce these emission rates, the entrained flow gasifier based plant recycles the Claus Plant tail gas back to the gasifier and injects nitrogen into the gas turbine combustor. Parsons projects that these steps will reduce the SO₂ emission rate to 0.023 lb/MMBtu (99.5 percent sulfur capture efficiency) and the NO_x emission rate to 0.067 lb/MMBtu (15 ppmvd). Using these new values, together with those projected for the PSA vent gas fired boiler, Parsons determined the plant pound per hour emission rates and then expressed them on a total plant heat input basis.

As shown in Table 7.4.1, the NO_x and particulate emissions of the two plants are comparable with the most significant differences occurring in SO₂ and CO emissions. Recycling the Claus Plant tail gas back to the gasifier is expected to increase the sulfur capture efficiency of the entrained flow gasifier plant from the Wabash 98 per cent plus values to 99.5 percent. With this improvement the entrained flow gasifier plant SO₂ emission is about 1/3rd of that of the PCFB gasifier plant as the latter operates with a 98.5 per cent sulfur capture efficiency. In contrast, the CO emission rate of the PCFB gasifier based plant is about 1/5th of that of the entrained flow gasifier plant.

Table 7.4.1 Comparison of Co-Production Plant Emissions

Type of Gasifier	Entrained Flow	PCFB
SO₂		
% Capture	99.5	98.5
lb/hr	106.9	289
lb/MMBtu	0.023	0.070
NO_x		
lb/hr	194	197
lb/MMBtu	0.042	0.048
CO		
lb/hr	297	45.1
lb/MMBtu	0.065	0.011
Particulate		
lb/hr	3.7	16.6
lb/MMBtu	0.001	0.004

7.5 Plant Costs and Economics

Table 7.5.1 compares the cost and economics of the PCFB and entrained flow gasifier co-production plants, the latter both with and without a spare gasifier equipment train. In both cases the PCFB based plant has the lowest total plant cost of \$625.4 million; this cost is 7.8 and 3.5 percent lower than the 3 and 2 train plants, respectively. This cost advantage will increase further if the PCFB gasifier plant's smaller site footprint is taken into consideration and the plant site is moved to a warm weather climate (the latter eliminates the need for the \$13 million CFB boiler building). Although the PCFB gasifier plant operates with a higher efficiency that gives it a lower fuel cost, its use of limestone, rather than amine solvent for sulfur capture, adds to its consumables cost. The limestone brings with it a feed cost of \$18/ton and increases the amount of plant solid waste for disposal costing \$12/ton. These cost adders together with, primarily, the assumed sale of sulfur at \$75/ton by the entrained flow gasifier plant, give the entrained flow plant a ~2 percent lower consumable cost. Despite this, the PCFB gasifier based plant, with its lower total plant cost and lower maintenance costs, has the lowest 10 year levelized hydrogen production price of \$6.75/MMBtu; this cost is 4.4 per cent less than the entrained flow plant with a spare train of

gasification equipment and, per Figure 6.2, is competitive with hydrogen produced by steam methane reforming at a natural gas price of approximately \$4 per million Btu.

The technologies employed by the two different co-production plants can be expected to advance with maturity and yield reductions in their hydrogen production costs. For the entrained flow plant this is envisioned as eliminating the spare train of gasification equipment for a \$0.46/MMBtu reduction in hydrogen costs. Although this would make the “future” entrained flow co-production plant competitive with the “present day” PCFB co-production plant, the latter’s production costs are also expected to reduce via technology maturity and its cost advantage maintained.

Table 7.5.2 compares the plants at the total plant cost account level and reveals the following major cost differences:

- 1.) With the entrained flow plant having, among other things, three gasification equipment trains, higher coal and oxygen flow rates, and solvent based sulfur capture, the following of its accounts are significantly higher:
 - a.) Account 2 covering coal-water slurry preparation/feeding equipment
 - b.) Account 4 containing gasifiers, fire-tube boilers, cyclones, filters, and oxygen supply systems
 - c.) Account 5 involving amine based sulfur removal, H₂S concentration, sulfur recovery, and syngas reheating, and humidification (PSA costs are the same as the PCFB gasifier plant)
 - d.) Account 6 containing the gas turbine
 - e.) Account 10 involving slag dewatering, handling, and storage
- 2.) With the PCFB gasifier plant incorporating a large CFB boiler system and a large steam turbine, the following of its accounts are significantly higher:
 - f.) Account 3 covering feedwater equipment
 - g.) Account 7 containing CFB boiler, fans, air heater, dry scrubber, baghouse filter, etc
 - h.) Account 8 containing the steam turbine
 - i.) Account 9 covering the cooling water system
 - j.) Account 14 containing the large \$13 million building that encloses the CFB boiler

Table 7.5.1 Comparison of Plant Capital Investments and Economics

Type of Gasifier	----E-Gas Entrained Flow---		--FW PCFB--
Number of Gasification Equipment Trains	3*	2**	1
Plant Capacity Factor, %	90	90	90
Net Power Output, MWe	251.9	251.9	255.5
Hydrogen Production Rate, lb/hr	21,703	21,703	21,753
Total Plant Cost, \$MM	678.5	647.8	625.4
Total Plant Investment, \$MM	712.4	680.1	656.7
Total Capital Requirement, \$MM	738.2	705.2	681.5
1st Year Operating & Maintenance Cost, \$MM	33.1	32.2	29.1
1st Year Consumables Cost Less Fuel, \$MM			
Water	0.8	0.8	1.2
Water Treatment	0.5	0.5	0.8
Limestone			4.6
Catalysts	0.4	0.4	0.1
Amine	0.1	0.1	
Ammonia			0.1
Waste Disposal	1.8	1.8	4.7
Subtotal	3.6	3.6	11.5
1st Year Byproduct Credit, \$MM			
Electricity	89.4	89.4	90.8
Sulfur	3.1	3.1	
1st Year Fuel Cost, \$MM	58.2	58.2	52.6
Levelized Cost of Hydrogen, \$/MMBtu	7.063	6.60	6.75

*Includes One Spare Train

**Allows for Technology Advancements that Eliminate Spare Train

Table 7.5.2 Comparison of Total Plant Costs by Accounts

Type of Gasifier		E-Gas Entrained Flow	FW PCFB	Difference E-Gas minus FW	% Difference From E-Gas
Number of Gasifiers		3	1		
Acct #	Account Title				
1	Coal & Sorbent Handling	32,369	29,566	-2,803	-8.7
2	Coal-Water Slurry Prep & Feed	40,909	30,086	-10,823	-26.5
3	Feedwater & Misc BOP Systems	19,766	24,436	4,670	23.6
4	Gasifier & Accessories	211,715	112,991	-98,724	-46.6
5	H ₂ Separation, Gas Cleanup, & Piping	91,051	44,484	-46,567	-51.1
6	Combustion Turbine & Accessories	58,099		-58,099	
7	CFB Boiler Syst/HRSG, Ducting, & Stack	49,885	168,842	118,957	238.5
8	Steam Turbine Generator	31,919	64,738	32,819	102.8
9	Cooling Water System	13,922	20,883	6,961	50.0
10	Slag/Ash Handling Systems	17,477	10,835	-6,642	-38.0
11	Accessory Electric Plant	55,916	52,188	-3,728	-6.7
12	Instrumentation & Control	26,193	24,447	-1,746	-6.7
13	Improvements to Site	10,720	10,720		0.0
14	Buildings & Structures	18,559	31,197	12,638	68.1
			0		
	Total	678,500	625,413	-53,087	-7.8

7.6 CO₂ Sequestering

There is growing concern that CO₂ emissions may have a detrimental effect on future weather/climate conditions. If needed, both co-production plants can be redesigned to incorporate CO₂ removal/separation for sequestration. Although analyses have not been performed, it is anticipated the plants would require the following major changes:

Entrained Flow Plant Changes

- 1.) add water gas shift to the power producing combined cycle leg of the plant
- 2.) add a CO₂ absorption tower to each plant leg downstream of their respective H₂S absorption towers

- 3.) add a CO₂ stripping tower servicing both legs of the plant
- 4.) add a CO₂ processing unit (dries and compresses CO₂ to pipeline pressure)
- 5.) convert the gas turbine to firing a hydrogen rich syngas

PCFB Plant Changes

- 1.) add CO₂ absorption and stripping towers to the syngas production leg of the plant
- 2.) add a second ASU system to the plant to supply oxygen to the CFB boiler
- 3.) redesign the CFB boiler for oxy-combustion (CFB fired with oxygen rather than air)
- 4.) add a CO₂ processing unit (dries and compresses CO₂ to pipeline pressure)

A detailed study, however, is needed to prepare plant heat and material balances, establish equipment design requirements, estimate equipment costs, and determine their impact on plant performance and economics.

8.0 Conclusions

Previous studies have shown that an air blown, fluidized bed gasifier, producing a low Btu syngas and a char sorbent residue, can be used to fuel a highly efficient combined cycle power generation plant. Such a plant, incorporating a Siemens Westinghouse 501G gas turbine, a conventional subcritical pressure steam turbine, and a PCFB boiler, is projected to have an efficiency of 48.2 percent (coal higher heating value basis) and a total plant cost of \$1,079/KW [8-1].

This study has investigated the feasibility of using the syngas from the PCFB gasifier to produce hydrogen rather than power a gas turbine. For such an application the PCFB gasifier is operated with oxygen instead of air to minimize the cost of gas processing equipment. When operated with oxygen, the PCFB gasifier produces a medium Btu syngas that has a hydrogen to carbon monoxide molar ratio favorable for the production of hydrogen. By incorporating water gas shifting and PSA technology the hydrogen can be separated from the syngas for sale to, in this study, a nearby refinery. The char residue from the PCFB gasifier and the PSA vent/purge gas are used to fuel a CFB boiler that produces steam for the gasifier and to drive a steam turbine for electric power generation. As a result, a PCFB gasifier based co-production plant is formed and the revenue from the sale of its electric power is used to defray the cost of hydrogen production.

If the coal-fueled, PCFB gasifier co-production plant sells its electricity at a price of \$45/MWhr, its 99.95 per cent pure hydrogen can be sold at a price of \$6.75/MMBtu, a price, per Figure 6.2, competitive with the steam methane reforming of \$4/MMBtu natural gas. With current natural gas spot prices well over this value, the potential for coal-fueled hydrogen production is promising. Any increase in the electricity sell price will increase the co-production plant revenue and enable its hydrogen sell price to be lowered while still recovering all costs and maintaining a 12 per cent return on equity; if the electricity sell price increases to \$50/MWhr then the hydrogen sell price, per Figure 5.4.1, can be reduced to \$5.68/MMBtu.

The performance and economics of the PCFB gasifier based co-production plant has also been compared to a comparable plant incorporating two stage, entrained flow gasification as exemplified by the E-GasTM gasifier at the Clean Coal Technology Wabash River Repowering

Project. Based on analyses performed by Parsons, the hydrogen and total plant cost of the PCFB gasifier based plant will be lower by at least 4.4 and 7.8 percent respectively.

Although not evaluated in this study, the PCFB gasifier based co-production plant can also incorporate CO₂ removal for sequestration; a detailed study, however, would have to be conducted to finalize its plant arrangement and determine the resulting plant performance and economics.

Based on the analyses conducted in this study, a coal-fueled, PCFB gasifier based co-production plant appears to be an economically viable means for meeting the nation's future needs for hydrogen and electricity.

9.0 References

- 1-1 Gupta, G, and McKensey, R., "Vision 21 Plants Utilizing HIPPS Technology", presented at Globe Ex 2000 International Energy Conference, Las Vegas, NA, July 23-28, 2000.
- 1-2 Rao, A.D., and Robson, F.L., "Vision 21-Coal Based Systems Integration", presented at 28th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL, March 10-13, 2003.
- 1-3 "Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal", EPRI, Palo Alto, CA, US DOE-Office of Fossil Energy, Germantown, MD and USDOE NETL, Pittsburgh, PA: 2000. 1000316
- 1-4 Rutkowski, M. D. et. al., "Capital and Operating Cost of Hydrogen Production from Coal Gasification", NETL Contract No DE-AM26-99FT40465, April 2003.
- 1-5 Goldstein, H., and McMahon, W., "Input to Comparative Study of Hydrogen Co-Production Cost---Foster Wheeler Partial Gasification Module versus E-Gas Multi-Train Gasifiers", January 2006.
- 2-1 Jorgensen, J., "The Mesaba Energy Project", Gasification Technologies 2005, San Francisco Ca., October 9-12, 2005.
- 2-2 Rigdon, R., and Avidan, A., "GE Energy and Bechtel's IGCC Reference Plant Offering", Gasification Technologies 2005, San Francisco CA., October 9-12, 2005.
- 3-1 Lynch,T., "Operating Experience at the Wabash Coal Gasification Repowering Project", Gasification Technologies 1998, San Francisco, CA., October, 1998.
- 3-2 "Thermie Demonstrates Biomass CFB Gasifier at Lahti", Modern Power Systems, February 1998.
- 3-3 Nieminen, J., et. al., "Progress Report: Varnamo Biomass Gasification Plant", Gasification Technologies 1999, San Francisco, CA., October 17-20, 1999.

- 3-4 Electric Power Research Institute, "TAG-Technical Assessment Guide", Vol 1, EPRI TR-102276-V1R7, Palo Alto, CA, Rev 7 June 1993.
- 4-1 ConocoPhillips, "E-Gas Technology for Coal Gasification", Presentation Made to Indiana Utility Regulatory Commission June 15, 2005.
- 5-1 Black and Veatch, "Fuel Capability Demonstration Test Report 1 for the JEA Large-Scale CFB Combustion Demonstration Plant", Rev. 1, September 3, 2004, DOE Contract No. DE-FC21-90MC27403.
- 6-1 Gray, D., et. al. "Polygeneration of SNG, Hydrogen, Power, and Carbon Dioxide from Texas Lignite", NETL Contract No. DE-AM26-99FT40465, December 2004.
- 7-1 Steigel, G. et. al., "DOE's Gasification Industry Interviews: Survey of Market Trends, Issues, and R&D Needs", Gasification Technologies 2001, San Francisco Ca., October 7-10, 2001.
- 7-2 Amick, A. et. al., "An Advanced IGCC Coal Power Plant", Twentieth Annual International Pittsburgh Coal Conference, Pittsburgh PA., September 15-19, 2001.
- 7-3 Holt, N. et. al., "Summary of Recent IGCC Studies of CO₂ Capture for Sequestration", Gasification Technologies 2003, San Francisco CA., October 12-15, 2003.
- 7-4 EPRI, "Atmospheric Fluidized Bed Combustion Technology's Status Reviewed", EPRI Journal On-Line, June 9, 2004.
- 7-5 Maryamchik, M. and Wietzke, D., "B&W IR-CFB Boiler Operating Experience Update and Design", Power-Gen International 1999, November 30-December 2, 1999, New Orleans LA.
- 7-6 DOE Report Number DOE/FE-0400, "Market Based Advanced Coal Power Systems---Final Report", May 1999.
- 8-1 Robertson, A., et. al., "Conceptual Design and Optimization of a 2nd Generation PFB Combustion Plant", Phase 1 Task 1 Topical Report, DOE/MC/21023-285, (DE0000412), September 1989.

10.0 Bibliography

Not applicable

11.0 Acronyms and Abbreviations

AFUDC	Allowance for Funds Used During Construction
AGR	Acid Gas Removal
ASU	Air Separation Unit
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
COS	Carbonyl Sulfide
DOE	U.S. Department of Energy
EPRI	Electric Power Research Institute
ETE	Effective Thermal Efficiency
FW	Foster Wheeler Development Corporation
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide
HF	Hydrogen Fluoride
H ₂	Hydrogen
H ₂ S	Hydrogen Sulfide
HHV	Higher Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
HT	High Temperature
ID	Inside Diameter
IGCC	Integrated Gasification Combined Cycle
INTREX TM	Integrated Recycle Heat Exchanger
IP	Intermediate Pressure
LP	Low Pressure
LT	Low Temperature
NH ₃	Ammonia
NO _x	Oxides of Nitrogen
OJ	Operating Jobs
O&M	Operating and Maintenance
Parsons	Parsons Infrastructure and Technology Group
PCFB	Pressurized Circulating Fluidized Bed
PGM	Partial Gasification Module
PSA	Pressure Swing Absorption
SMR	Steam Methane Reforming
SNCR	Selective Non Catalytic Reduction
SO ₂	Sulfur Dioxide
TCR	Total Capital Requirement
TPC	Total Plant Cost
TPI	Total Plant Investment
US	United States

Appendix A

E-Gas Entrained Flow Gasifier Based Co-Production Plant with Spare Gasifier

A1. List of Major Entrained Flow Co-Production Plant Equipment by Account**ACCOUNT 1 COAL RECEIVING AND HANDLING (serves entire plant)**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty.</u>
1	Rotary Car Dumper and Receiving Hoppers	N/A	100 ton	1
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	100 ton	2
7	Stacker-Reclaimer		900 tph	1
8	Feeder	Vibratory	200 tph	2
9	Conveyor 3	48" belt	400 tph	1
10	Crusher Tower	N/A	400 tph	1
11	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
12	Crusher	Granulator reduction	400 tph	2
13	Crusher	Impactor reduction	400 tph	2
14	As-Fired Coal Sampling System	Swing hammer	N/A	2
15	Conveyor 4	48" belt	400 tph	1
16	Transfer Tower	N/A	400 tph	1
17	Conveyor to Slurry Prep Silos	N/A	400 tph	1
18	Slurry Prep Silo w/Vent Filter and Slide Gates	N/A	1500 ton	2

ACCOUNT 2 COAL-WATER SLURRY PREPARATION AND FEED
(serves entire plant)

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty.</u>
1	Feeder	Vibrating	200 tph	2@100%
2	Rod Mill	Rotary	200 tph	2@100%
3	Surge Bin	Vertical, cylindrical	800 tons	1
4	Feeder	Weigh belt	200 tph	2@100%
5	Slurry Water Pumps	Centrifugal	360 gpm @ 500 ft	2@100%
6	Slurry Water Storage Tank	Vertical	40,000 gal	1
7	Rod Mill Product Tank	Vertical	52,000 gal	2
8	Slurry Transfer Pumps	Centrifugal, elastomer lined or hard metal	650 gpm @100ft	4
9	Slurry Storage Tank with Agitator	Vertical	120,000 gal (4 hrs)	3
10	Slurry Feed Pumps, 1 st Stage	Progressing Cavity	120 gpm @ 1,250 ft	3@50%
11	Slurry Feed Pumps, 2nd Stage	Progressing Cavity	315 gpm @ 1,250 ft	3@50%
12	LT Slurry Heater	Shell and tube	29 x 10 ⁶ Btu/h	3
13	HT Slurry Heater	Shell and tube	10 x 10 ⁶ Btu/h	3

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS BOP SYSTEMS

ACCOUNT 3A-1 CONDENSATE AND FEEDWATER SYSTEM-POWER TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Condensate. Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vertical canned	1,100 gpm @ 400 ft	2@100%
3	Deaerator	Horizontal spray type	650,000 lb/h 205°F to 240°F	1
4	LP Feed Pump	Horizontal centrifugal single stage	400 gpm/400 ft	2@100%
5	HP Feed Pump	Ring-segment type, multi-staged, centrifugal.	1,250 gpm @ 4800 ft	2@100%

ACCOUNT 3A-2 CONDENSATE AND FEEDWATER SYSTEM-H₂ TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Condensate. Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vertical canned	1,200 gpm @ 400 ft	2@100%
3	Deaerator	Horizontal spray type	650,000 lb/h 205°F to 240°F	1
4	LP Feed Pump	Horizontal centrifugal single stage	400 gpm/400 ft	2@100%
5	HP Feed Pump	Ring-segment type, multi- stage, centrifugal.	1,250 gpm @ 4,000 ft	2@100%

ACCOUNT 3B MISCELLANEOUS EQUIPMENT (serves entire plant)

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Auxiliary Boiler	Shop fabricated, water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Reciprocating, single stage, double acting, horizontal	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horizontal centrifugal, double suction	200 ft, 1,200 gpm	2
5	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 1,200 gpm	2
6	Fire Service Booster Pump	Two-stage horizontal centrifugal	250 ft, 1,200 gpm	1
7	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1,000 gpm	1
8	Trash Rack/Rake			1
9	Traveling Screen			1
10	Screen Wash Pump			2
11	Clarifier		3,500 gpm	1
12	Chemical Feed Skid			1
13	Filter		3,500 gpm	1
14	Raw Water Pumps	SS, single suction	60 ft, 3,500 gpm	2
15	Filtered Water Pumps	SS, single suction	160 ft, 35100 gpm	2
16	Filtered Water Tank	Vertical, cylindrical	1,000,000 gal	1
17	Steam Cycle Makeup Demineralizer	Reverse Osmosis Unit	440 gpm	1
18	Chemical Feed Skid			1
19	Steam Cycle Makeup Polisher	Electro Dialysis Unit	440 gpm	1
20	Sour Water Stripper System	Vendor supplied	205,000 lb/h sour water	1
21	Liquid Waste Treatment System	Vendor supplied	60 gpm	1

ACCOUNT 4 GASIFIER AND ACCESSORIES**ACCOUNT 4A GASIFICATION****(3 gasifier trains provided, one each for H₂ and power trains, one swing spare)**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Gasifier, including char recycle and slag depressurizing and dewatering system	Pressurized entrained bed/syngas cooler	2,250 std (dry-coal basis) @ 515 psia	3
2	Raw Gas Cooler Steam Generator	Fire tube boiler	1,800 psig/621°F 466 MMBtu/h	3
3	Cyclone	Carbon steel, abrasion resistant liner	500 psia, 700F	3
5	Medium-Temperature Candle Filter with Back Pulse Candle Cleaning Skid	Sintered stainless candle, carbon steel vessel	484 psia, 690°F	3
6	Syngas Recycle Compressor	Centrifugal	99,000 lb/hr. PR=1.35:1	3
7	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	420,000 lb/h, medium-Btu gas	2

ACCOUNT 4B AIR SEPARATION PLANT**(serves entire plant, 2 trains at 50% capacity)**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Air Compressor	Centrifugal, multi-stage	144,000 scfm, 70 psia discharge pressure	2
2	Cold Box	Vendor supplied	1,750 ton/day O ₂	2
3	Oxygen Compressor	Centrifugal, multi-stage	29,000 scfm, 800 psig discharge pressure	2
4	Liquid Oxygen Storage Tank	Vertical	60' dia. x 80' vert	2
5	DeNOx Nitrogen Compressor	Centrifugal, multi-stage	110,000 scfm, 344 psig discharge pressure	1
6	Gasifier Nitrogen Compressor	Centrifugal, multi-stage	1,750 scfm at 525 psig	2

ACCOUNT 5 SYNGAS SHIFT AND CLEANUP

ACCOUNT 5A WATER-GAS SHIFT AND RAW GAS COOLING

ACCOUNT 5A-1 H₂ PRODUCTION TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	High Temperature Shift Reactor No. 1	Fixed bed	500 psia, 750°F, 266 cu ft of catalyst	1
2	High Temperature Shift Reactor No. 2	Fixed bed	500 psia, 622°F, 261 cu ft of catalyst	1
3	Low Temperature Shift Reactor	Fixed bed	500 psia, 450°F 230 cu ft of catalyst	1
4	HP Steam Generator No. 1	Shell and tube	70 x 10 ⁶ Btu/h @ 1700 psia and 613°F	1
5	HP Steam Generator No. 2	Shell and tube	70 x 10 ⁶ Btu/h @ 1700 psia and 613°F	1
6	IP Steam Generator	Shell and tube	45 x 10 ⁶ Btu/h @ 400 psia and 450°F	1
7	LP Steam Generator	Shell and tube	20 x 10 ⁶ Btu/h @ 200 psia and 382°F	1
8	Syngas Gas to gas Reheater	Shell and Tube	33 x 10 ⁶ Btu/hr Shell 448 psia/550F Tube: 433 psia/537F	
9	Raw Gas Coolers	Shell and tube with condensate drain	150 x 10 ⁶ Btu/h	2
10	Raw Gas Knock Out Drum	Vertical with mist eliminator	400 psia, 130°F	1
11	Raw Syngas Steam Generator	Shell and Tube	400 psia, 690F	1
12	Syngas Water Scrubber		474 psia, 330F	1
13	Scrubber Reflux Cooler	Shell and Tube	505 psia, 285F	1
14	Sour Water Collection Tank			1

ACCOUNT 5 SYNGAS SHIFT AND CLEANUP**ACCOUNT 5A WATER-GAS SHIFT AND RAW GAS COOLING****ACCOUNT 5A-2 POWER TRAIN**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Syngas Reheater (gas/gas)	Shell and Tube	500 psig/700F	1
2	COS Hydrolysis Reactor	Packed Column	450 psig/400F	1
3	Saturator Hot Water Heater	Shell and Tube	500 psig/620F	1
4	Syngas Water Scrubber	Tray	450 psig/330F	1
5	Scrubber Reflux Cooler	Shell and Tube	450 psig/330F	1
6	Raw Gas Coolers	Shell and Tube		3
7	Knockout Drum			1
8	Sour Gas Stripper	Column		1
9	Stripper Reflux Heater	Shell and Tube		1

ACCOUNT 5B ACID GAS REMOVAL AND GAS CONDITIONING**ACCOUNT 5B-1 H₂ PRODUCTION TRAIN**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Amine Absorber A1	Column	133,000 scfm (6,500 acfm), 390 psia, 103°F	1
2	Sulfur Plant	Vendor design	127 tpd elemental sulfur	1
3	PSA Unit	Fixed bed	341,522 lb/he syngas for 101 MMscfd H ₂ @ 370 psia	1

ACCOUNT 5B-2 POWER TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Amine Absorber A2	Column	94,000 scfm (4,600 acfm), 413 psia, 103°F	1
2	Fuel Gas Saturator	Column	445 psia, 325F	1
3	Fuel Gas Reheater	Shell and Tube	395 psia, 535F	1

ACCOUNT 5C SULFUR RECOVERY and TAIL GAS RECYCLE

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Claus Furnace			1
2	Converter Preheater			2
3	Sulfur Converter			2
4	Sulfur Condenser		43 tpd	3
5	Hydrogenation Reactor Preheater			1
6	Hydrogenation Reactor			1
7	Contact Cooler			1
8	Tail Gas Recycle Comp.	Centrifugal, inter-cooled	46,333 lb/hr, Pr 45:1	2@100%
9	Regenerator for Amine Absorbers A1 and A2	Column	183,372 lb/hr gas release	1
10	Acid Gas Concentrator		Twin column	1
11	H ₂ S Preheater	Shell and Tube		1
12	Oxygen Preheater	Shell and Tube		1
13	Stripper Gas Preheater	Shell and Tube		1

ACCOUNT 6 COMBUSTION TURBINE/and ACCESSORIES-POWER TRAIN ONLY

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u> <u>Drums</u>	<u>Qty</u>
1	GE 7FA Combustion Turbine Generator	Frame Type, Syngas Fired	197 MWe at ISO Conditions firing syngas	1
2	Heat Recovery Steam Generator	Unfired, Two Drum, Reheater	589,000 lb/h superheated steam at 1685 psig/1005F 564,482 lb/hr reheat steam at 370 psig/1005F	1
3	Stack	Carbon steel plate, type 409 stainless steel liner	213 ft high x 24 ft dia.	1

ACCOUNT 7 FIRED BOILER AND STACK-H₂ PRODUCTION TRAIN ONLY

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u> <u>Drums</u>	<u>Qty</u>
1	Fired Steam Generator	Drum Type, Forced Draft with 2000 hp FD fan	408,000 lb/h superheated steam at 1275 psig/955°F	1
2	Stack	Carbon steel plate, type, 409 stainless steel liner	213 ft high x 12 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES**ACCOUNT 8-1 H₂ PRODUCTION TRAIN**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u> <u>(per each)</u>	<u>Qty</u>
1	50 MW Steam Turbine Generator	Non-Reheat, TC1F26, Axial Exhaust, TEWAC Generator	1275 psig/955°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic		1
5	Generator Coolers	Plate and frame		2
6				1
7	Surface Condenser	Single pass, divided waterbox	530 MM Btu/h, 2.0 in Hga	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 8-2 POWER TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition (per each)</u>	<u>Qty</u>
1	100 MW Steam Turbine Generator	Reheat, TC1F33.5, Axial Exhaust, TEWAC Generator	1600 psig/1000F/1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic		1
5	Generator Coolers	Plate and frame		2
6				1
7	Surface Condenser	Single pass, divided waterbox	500 MM Btu/h, 2.0 in Hga	1
8	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM (serves both H₂ and Power Trains)

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition (per each)</u>	<u>Qty</u>
1	Circ. Water Pumps	Vertical wet pit	48,000 gpm @ 60 ft TDH	3@ 50%
2	Cooling Tower	Mechanical draft, multi-cell, 19F Approach/21F Range at 53F WB	96,000 gpm	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING**ACCOUNT 10A SLAG DEWATERING AND REMOVAL**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Slag Dewatering System	Vendor proprietary	230 tpd	3
2	Slag Conveyor	Drag Chain	10 tph	3
3	Slag Conveyor	Drag Chain	20 tph	2
4	Bucket Elevator		20 tph	2
5	Slag Silo	Vertical, cylindrical, bolted steel	1400 tons	1
6	Truck Unloader	Telescoping Chute	60 tph	2

A2. Total Plant Cost Estimate

		Client: DEPARTMENT OF ENERGY Project: Hydrogen and Electricity Coproduction IGCC Power Plant				Report Date: 18-Nov-05				
TOTAL PLANT COST SUMMARY										
Case: H2 & Electric Coproduction -E-Gas IGCC Plant Size: 251.90 MW _{net} 260.4 H2 Tons / Day		Estimate Type: Conceptual		Cost Base (January) 2005 ; \$x1000						
Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
1	COAL & SORBENT HANDLING	12,595	2,395	9,332	653	24,976	1,998		5,395	32,369
2	COAL-WATER SLURRY PREP & FEED	15,210		13,936	975	33,437	2,675	0	4,798	40,909
3	FEEDWATER & MISC. BOP SYSTEMS	6,800		4,510	316	14,745	1,180		3,840	19,766
4	GASIFIER & ACCESSORIES									
4.1	Gasifier & Auxiliaries	45,705		24,224	1,696	71,624	5,730	0	7,735	85,090
4.2	Syngas Cooling	18,721		15,654	1,096	35,471	2,838	0	3,831	42,139
4.3	ASU/Oxidant Compression	54,089		w/equip.	0	54,089	4,327		5,842	64,258
4.4-4.9	Other Gasification Equipment		5,398	5,968	418	15,459	1,237	0	3,533	20,228
	Subtotal 4	122,190	5,398	45,846	3,209	176,643	14,131	0	20,941	211,715
5	HYDROGEN SEPARATION/GAS CLEANUP & PIPING	46,318	2,458	19,872	1,391	70,039	5,603	0	15,408	91,051
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Expander Turbine/Generator	45,333		2,967	208	48,507	3,881	0	5,239	57,626
6.2-6.9	Combustion Turbine Accessories		160	165	12	337	27		109	472
	Subtotal 6	45,333	160	3,132	219	48,844	3,907	0	5,348	58,099
7	HRSG, DUCTING & STACK									
7.1	Heat Recover Stream Generator	16,189		1,975	138	18,302	1,464		1,977	21,743
7.2-7.9	HRSG Accessories, Ductwork and Stack	15,290	1,618	5,856	410	23,174	1,854		3,115	28,142
	Subtotal 7	31,480	1,618	7,830	548	41,476	3,318		5,091	49,885
8	STEAM TURBINE GENERATOR									
8.1	ExpanderTurbine & Accessories	14,091		2,087	146	16,325	1,306		1,763	19,394
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	6,158	423	3,074	215	9,869	790		1,866	12,525
	Subtotal 8	20,249	423	5,161	361	26,194	2,096		3,629	31,919
9	COOLING WATER SYSTEM	4,604	2,413	3,682	257	10,957	877		2,089	13,922
10	ASH/SPENT SORBENT HANDLING SYS	7,176	1,435	5,424	380	14,414	1,153	0	1,910	17,477
11	ACCESSORY ELECTRIC PLANT	21,639	6,747	15,089	1,056	44,531	3,562		7,822	55,916
12	INSTRUMENTATION & CONTROL	10,851		8,408	589	21,041	1,683		3,468	26,193
13	IMPROVEMENTS TO SITE	2,270	1,237	3,858	270	7,635	611		2,474	10,720
14	BUILDINGS & STRUCTURES		5,983	7,257	508	13,748	1,100		3,712	18,559
TOTAL COST		\$346,717	\$39,229	\$153,335	\$10,733	\$548,680	\$43,894	\$0	\$85,926	\$678,500

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: H2 & Electric Coproduction -E-Gas IGCC
Plant Size: 251.9 MW/net
260.4 H2 Tons / Day
Estimate Type:
Cost Base (January) 2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O. & Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
1	COAL & SORBENT HANDLING									
	1.1 Coal Receive & Unload	3,308		1,545	108	\$4,961	397		1,072	\$6,430
	1.2 Coal Stackout & Reclaim	4,274		989	69	\$5,332	427		1,152	\$6,911
	1.3 Coal Conveyors & Yard Breaker	3,975		979	69	\$5,023	402		1,085	\$6,509
	1.4 Other Coal Handling	1,039		226	16	\$1,281	102		277	\$1,660
	1.5 Sorbent Receive & Unload									
	1.6 Sorbent Stackout & Reclaim									
	1.7 Sorbent Conveyors									
	1.8 Other Sorbent Handling									
	1.9 Coal & Sorbent Hnd. Foundations									
	SUBTOTAL 1.	\$12,595	\$2,395	\$9,332	\$653	\$24,976	\$1,998		\$5,395	\$32,369
2	COAL-WATER SLURRY PREP & FEED									
	2.1 Coal Crushing - Milling	2,109	313	672	47	\$3,140	251		678	\$4,069
	2.2 Coal Slurry Delivery/ Storage	726	154	108	8	\$995	80		215	\$1,290
	2.3 Coal Slurry Injection System	11,759		9,992	699	\$22,450	1,796		2,425	\$26,671
	2.4 Misc. Coal Prep & Feed	617	397	1,285	90	\$2,390	191		516	\$3,097
	2.5 Sorbent Prep Equipment									
	2.6 Sorbent Storage & Feed									
	2.7 Sorbent Injection System									
	2.8 Booster Air Supply System									
	2.9 Coal & Sorbent Feed Foundation									
	SUBTOTAL 2.	\$15,210	\$3,315	\$13,936	\$975	\$33,437	\$2,675		\$4,798	\$40,909
3	FEEDWATER & MISC. BOP SYSTEMS									
	3.1 Feedwater System	935	1,724	824	58	\$3,540	283		765	\$4,588
	3.2 Water Makeup & Pretreating	466	47	227	16	\$756	61		245	\$1,062
	3.3 Other Feedwater Subsystems	557	197	161	11	\$926	74		200	\$1,201
	3.4 Service Water Systems	36	73	229	16	\$354	28		115	\$497
	3.5 Other Boiler Plant Systems	1,524	583	1,308	92	\$3,506	280		757	\$4,544
	3.6 FO Supply Sys & Nat Gas	117	209	353	25	\$704	56		152	\$912
	3.7 Waste Treatment Equipment	926		461	32	\$1,419	114		460	\$1,993
	3.8 Misc. Power Plant Equipment	2,239	287	947	66	\$3,539	283		1,147	\$4,969
	SUBTOTAL 3.	\$6,800	\$3,120	\$4,510	\$316	\$14,745	\$1,180		\$3,840	\$19,766
4	GASIFIER & ACCESSORIES									
	4.1 Gasifier & Auxiliaries	45,705		24,224	1,696	\$71,624	5,730		7,735	\$85,090
	4.2 Syngas Cooling	18,721		15,654	1,096	\$35,471	2,638		3,831	\$42,139
	4.3 ASU/Oxidant Compression	54,089		w/equip.		\$54,089	4,327		5,842	\$64,258
	4.4 Nitrogen Compressor	3,675		551	39	\$4,265	341		461	\$5,067
	4.5 Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2						
	4.6 Other Gasification Equipment		1,842	677	47	\$2,567	205		277	\$3,050
	4.8 Major Component Rigging	w/4.1&4.2		w/4.1&4.2						
	4.9 Gasification Foundations		3,555	4,739	332	\$8,627	690		2,795	\$12,112
	SUBTOTAL 4.	\$122,190	\$5,398	\$45,846	\$3,209	\$176,643	\$14,131		\$20,941	\$211,715

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: H2 & Electric Coproduction -E-Gas IGCC
Plant Size: 251.9 MW/net
260.4 H2 Tons / Day
Estimate Type:

Cost Base (January) 2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
5	HYDROGEN SEPARATION/GAS CLEANUP									
	5.1 Shift Reactors	9,177		4,187	293	\$13,657	1,093		2,950	\$17,700
	5.2 AGR & H2S Systems	10,716		3,429	240	\$14,385	1,151		3,107	\$18,643
	5.3 Sulfur Recovery	6,336		7,921	554	\$14,811	1,185		3,199	\$19,195
	5.4 Raw Gas Coolers	7,428		1,496	105	\$9,028	722		1,950	\$11,701
	5.5 PSA Unit	11,282		542	38	\$11,861	949		2,562	\$15,372
	5.6 Sour Gas System	1,380	425	217	15	\$2,037	163		440	\$2,640
	5.7 Fuel Gas Piping		965	656	46	\$1,667	133		360	\$2,161
	5.9 HGCU Foundations		1,068	1,424	100	\$2,591	207		840	\$3,638
	SUBTOTAL 5.	\$46,318	\$2,458	\$19,872	\$1,391	\$70,039	\$5,603		\$15,408	\$91,051
6	COMBUSTION TURBINE/ACCESSORIES									
	6.1 Expander Turbine/Generator	45,333		2,967	208	\$48,507	3,881		5,239	\$57,626
	6.2 Combustion Turbine Accessories	w/6.1		w/6.1						
	6.3 Compressed Air Piping		160	165	12	\$337	27		109	\$472
	6.9 Combustion Turbine Foundations									
	SUBTOTAL 6.	\$45,333	\$160	\$3,132	\$219	\$48,844	\$3,907		\$5,348	\$58,099
7	HRSG, DUCTING & STACK									
	7.1 Heat Recovery Steam Generator	16,189		1,975	138	\$18,302	1,464		1,977	\$21,743
	7.2 Gas Fired Boiler	11,368		2,842	199	\$14,409	1,153		1,556	\$17,118
	7.3 Ductwork		720	553	39	\$1,312	105		283	\$1,701
	7.4 Stack for HRSG	2,354		758	53	\$3,165	253		342	\$3,760
	7.5 Stack for Gas Fired Boiler	1,569		506	35	\$2,110	169		228	\$2,507
	7.9 HRSG,Duct & Stack Foundations		897	1,196	84	\$2,177	174		705	\$3,057
	SUBTOTAL 7.	\$31,480	\$1,618	\$7,830	\$548	\$41,476	\$3,318		\$5,091	\$49,885
8	STEAM TURBINE GENERATOR									
	8.1 Steam TG & Accessories	14,091		2,087	146	\$16,325	1,306		1,763	\$19,394
	8.2 Turbine Plant Auxiliaries	97		203	14	\$314	25		34	\$373
	8.3 Condenser & Auxiliaries	2,505		623	44	\$3,171	254		343	\$3,768
	8.4 Steam Piping	3,556		1,684	118	\$5,358	429		1,157	\$6,944
	8.9 TG Foundations		423	564	39	\$1,026	82		332	\$1,440
	SUBTOTAL 8.	\$20,249	\$423	\$5,161	\$361	\$26,194	\$2,096		\$3,629	\$31,919
9	COOLING WATER SYSTEM									
	9.1 Cooling Towers	3,533		665	47	\$4,244	340		458	\$5,042
	9.2 Circulating Water Pumps	517		42	3	\$562	45		61	\$668
	9.3 Circ.Water System Auxiliaries	63		7		\$71	6		8	\$84
	9.4 Circ.Water Piping		1,161	1,168	82	\$2,410	193		521	\$3,124
	9.5 Make-up Water System	140		179	13	\$331	27		72	\$430
	9.6 Component Cooling Water Sys	351	398	265	19	\$1,033	83		223	\$1,339
	9.9 Circ.Water System Foundations		854	1,356	95	\$2,305	184		747	\$3,236
	SUBTOTAL 9.	\$4,604	\$2,413	\$3,682	\$257	\$10,957	\$877		\$2,089	\$13,922
10	ASH/SPENT SORBENT HANDLING SYS									
	10.1 Slag Dewatering & Cooling	4,957		4,193	293	\$9,443	755		1,020	\$11,218
	10.2 Gasifier Ash Depressurization									
	10.3 Other Ash Recovery Equipment									
	10.4 Ash Storage Silos	508		473	33	\$1,014	81		164	\$1,259
	10.5 Ash Transport & Feed Equipment	661		141	10	\$812	65		131	\$1,008
	10.6 Misc. Ash Handling Equipment	1,051	1,219	331	23	\$2,624	210		425	\$3,258
	10.9 Ash/Spent Sorbent Foundations		215	287	20	\$522	42		169	\$733
	SUBTOTAL 10.	\$7,176	\$1,435	\$5,424	\$380	\$14,414	\$1,153		\$1,910	\$17,477

Client: DEPARTMENT OF ENERGY
 Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: H2 & Electric Coproduction -E-Gas IGCC
 Plant Size: 251.9 MW_{net}
 260.4 H2 Tons / Day

Estimate Type:

Cost Base (January)

2005 : \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
11	ACCESSORY ELECTRIC PLANT									
11.1	Generator Equipment	2,559		431	30	\$3,020	242		326	\$3,588
11.2	Station Service Equipment	6,607		462	32	\$7,101	568		767	\$8,437
11.3	Switchgear & Motor Control	5,268		743	52	\$6,063	485		962	\$7,530
11.4	Conduit & Cable Tray		3,010	8,455	592	\$12,057	965		2,604	\$15,626
11.5	Wire & Cable		3,231	2,889	202	\$6,322	506		1,366	\$8,194
11.6	Protective Equipment		231	690	48	\$969	77		157	\$1,203
11.7	Standby Equipment	1,189		22	2	\$1,212	97		196	\$1,506
11.8	Main Power Transformers	6,017		716	50	\$6,784	543		1,099	\$8,425
11.9	Electrical Foundations			680	48	\$1,003	80		325	\$1,408
	SUBTOTAL 11.	\$21,639	\$6,747	\$15,089	\$1,056	\$44,531	\$3,562		\$7,822	\$55,916
12	INSTRUMENTATION & CONTROL									
12.1	IGCC Control Equipment	1,333								
12.2	Combustion Turbine Control									
12.3	Steam Turbine Control									
12.4	Other Major Component Control	893		462	32	\$1,388	111		225	\$1,723
12.5	Signal Processing Equipment	w/12.7		w/12.7						
12.6	Control Boards, Panels & Racks	214		107	8	\$329	26		71	\$426
12.7	Computer & Accessories	6,837		213	15	\$7,065	565		763	\$8,394
12.8	Instrument Wiring & Tubing		2,527	7,032	492	\$10,051	804		2,171	\$13,026
12.9	Other I & C Equipment	1,574		593	42	\$2,208	177		239	\$2,624
	SUBTOTAL 12.	\$10,851	\$2,527	\$8,408	\$589	\$21,041	\$1,683		\$3,468	\$26,193
13	IMPROVEMENTS TO SITE									
13.1	Site Preparation		36	644	45	\$725	58		235	\$1,018
13.2	Site Improvements		1,201	1,327	93	\$2,620	210		849	\$3,679
13.3	Site Facilities	2,270		1,887	132	\$4,290	343		1,390	\$6,023
	SUBTOTAL 13.	\$2,270	\$1,237	\$3,858	\$270	\$7,635	\$611		\$2,474	\$10,720
14	BUILDINGS & STRUCTURES									
14.1	Combustion Turbine Area		251	142	10	\$403	32		109	\$545
14.2	Turbine Building		2,064	2,933	205	\$5,203	416		1,405	\$7,024
14.3	Administration Building		496	359	25	\$880	70		238	\$1,188
14.4	Circulation Water Pump House		98	52	4	\$153	12		41	\$206
14.5	Water Treatment Buildings		618	601	42	\$1,261	101		340	\$1,702
14.6	Machine Shop		254	173	12	\$438	35		118	\$592
14.7	Warehouse		409	263	18	\$690	55		186	\$932
14.8	Gas Fired Boiler & Other Buildings		1,246	1,690	118	\$3,054	244		825	\$4,123
14.9	Waste Treating Building & Str.		548	1,045	73	\$1,665	133		450	\$2,248
	SUBTOTAL 14.		\$5,983	\$7,257	\$508	\$13,748	\$1,100		\$3,712	\$18,559
TOTAL COST		\$346,717	\$39,229	\$153,335	\$10,733	\$548,680	\$43,894		\$85,926	\$678,500

Appendix B

E-Gas Entrained Flow Gasifier Based Co-Production Plant without Spare Gasifier

B1. Total Plant Cost Estimate

Client: DEPARTMENT OF ENERGY		Report Date: 18-Nov-05								
Project: Hydrogen and Electricity Coproduction IGCC Power Plant		TOTAL PLANT COST SUMMARY								
Case: OPTION 2 TRAIN GASIFIERS H2 & Electric Coproduction -E-Gas IGCC										
Plant Size: 251.90 MW _{net}		Estimate Type: Conceptual		Cost Base -Jan 2005 ; \$x1000						
260.4 H2 Tons / Day										
Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
1	COAL & SORBENT HANDLING	12,595	2,395	9,332	653	24,976	1,998		5,395	32,369
2	COAL-WATER SLURRY PREP & FEED	15,210		13,936	975	33,437	2,675	0	4,798	40,909
3	FEEDWATER & MISC. BOP SYSTEMS	6,800		4,510	316	14,745	1,180		3,840	19,766
4	GASIFIER & ACCESSORIES									
4.1	Gasifier & Auxiliaries	30,470		16,149	1,130	47,750	3,820	0	5,157	56,726
4.2	Syngas Cooling	18,721		15,654	1,096	35,471	2,838	0	3,831	42,139
4.3	ASU/Oxidant Compression	54,089		w/equip.	0	54,089	4,327		5,842	64,258
4.4-4.9	Other Gasification Equipment		4,941	5,359	375	14,350	1,148	0	3,174	18,671
	Subtotal 4	106,955	4,941	37,162	2,601	151,659	12,133	0	18,003	181,795
5	HYDROGEN SEPARATION/GAS CLEANUP & PIPING	46,318	2,458	19,872	1,391	70,039	5,603	0	15,408	91,051
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Expander Turbine/Generator	45,333		2,967	208	48,507	3,881	0	5,239	57,626
6.2-6.9	Combustion Turbine Accessories		160	165	12	337	27		109	472
	Subtotal 6	45,333	160	3,132	219	48,844	3,907	0	5,348	58,099
7	HRSG, DUCTING & STACK									
7.1	Heat Recover Stream Generator	16,189		1,975	138	18,302	1,464		1,977	21,743
7.2-7.9	HRSG Accessories, Ductwork and Stack	15,290	1,618	5,856	410	23,174	1,854		3,115	28,142
	Subtotal 7	31,480	1,618	7,830	548	41,476	3,318		5,091	49,885
8	STEAM TURBINE GENERATOR									
8.1	Expander Turbine & Accessories	14,091		2,087	146	16,325	1,306		1,763	19,394
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	6,158	423	3,074	215	9,869	790		1,866	12,525
	Subtotal 8	20,249	423	5,161	361	26,194	2,096		3,629	31,919
9	COOLING WATER SYSTEM	4,604	2,413	3,682	257	10,957	877		2,089	13,922
10	ASH/SPENT SORBENT HANDLING SYS	7,176	1,435	5,424	380	14,414	1,153	0	1,910	17,477
11	ACCESSORY ELECTRIC PLANT	21,402	6,617	14,824	1,038	43,881	3,510		7,705	55,096
12	INSTRUMENTATION & CONTROL	10,851		8,408	589	21,041	1,683		3,468	26,193
13	IMPROVEMENTS TO SITE	2,270	1,237	3,858	270	7,635	611		2,474	10,720
14	BUILDINGS & STRUCTURES		5,983	7,257	508	13,748	1,100		3,712	18,559
TOTAL COST		\$331,244	\$38,643	\$144,386	\$10,107	\$523,046	\$41,844	\$0	\$82,870	\$647,760

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: OPTION 2 TRAIN GASIFIERS H2 & Electric Coproduction -E-Gas IGCC
Plant Size: 251.9 MW_{net}
260.4 H2 Tons / Day

Estimate Type:

Cost Base (January)

2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
1	COAL & SORBENT HANDLING									
1.1	Coal Receive & Unload	3,308		1,545	108	\$4,961	397		1,072	\$6,430
1.2	Coal Stackout & Reclaim	4,274		989	69	\$5,332	427		1,152	\$6,911
1.3	Coal Conveyors & Yard Breaker	3,975		979	69	\$5,023	402		1,085	\$6,509
1.4	Other Coal Handling	1,039		226	16	\$1,281	102		277	\$1,660
1.5	Sorbent Receive & Unload									
1.6	Sorbent Stackout & Reclaim									
1.7	Sorbent Conveyors									
1.8	Other Sorbent Handling									
1.9	Coal & Sorbent Hnd. Foundations		2,395	5,593	391	\$8,380	670		1,810	\$10,860
	SUBTOTAL 1.	\$12,595	\$2,395	\$9,332	\$653	\$24,976	\$1,998		\$5,395	\$32,369
2	COAL-WATER SLURRY PREP & FEED									
2.1	Coal Crushing - Milling	2,109	313	672	47	\$3,140	251		678	\$4,069
2.2	Coal Slurry Delivery/ Storage	726	154	108	8	\$985	80		215	\$1,290
2.3	Coal Slurry Injection System	11,759		9,992	699	\$22,450	1,796		2,425	\$26,671
2.4	Misc. Coal Prep & Feed	617	397	1,285	90	\$2,390	191		516	\$3,097
2.5	Sorbent Prep Equipment									
2.6	Sorbent Storage & Feed									
2.7	Sorbent Injection System									
2.8	Booster Air Supply System									
2.9	Coal & Sorbent Feed Foundation		2,451	1,879	132	\$4,462	357		964	\$5,782
	SUBTOTAL 2.	\$15,210	\$3,315	\$13,936	\$975	\$33,437	\$2,675		\$4,798	\$40,909
3	FEEDWATER & MISC. BOP SYSTEMS									
3.1	Feedwater System	935	1,724	824	58	\$3,540	283		765	\$4,588
3.2	Water Makeup & Pretreating	466	47	227	16	\$756	61		245	\$1,062
3.3	Other Feedwater Subsystems	557	197	161	11	\$926	74		200	\$1,201
3.4	Service Water Systems	36	73	229	16	\$354	28		115	\$497
3.5	Other Boiler Plant Systems	1,524	583	1,308	92	\$3,506	280		757	\$4,544
3.6	FO Supply Sys & Nat Gas	117	209	353	25	\$704	56		152	\$912
3.7	Waste Treatment Equipment	926		461	32	\$1,419	114		460	\$1,993
3.8	Misc. Power Plant Equipment	2,239	287	947	66	\$3,539	283		1,147	\$4,969
	SUBTOTAL 3.	\$6,800	\$3,120	\$4,510	\$316	\$14,745	\$1,180		\$3,840	\$19,766
4	GASIFIER & ACCESSORIES									
4.1	Gasifier & Auxiliaries	30,470		16,149	1,130	\$47,750	3,820		5,157	\$56,726
4.2	Syngas Cooling	18,721		15,654	1,096	\$35,471	2,838		3,831	\$42,139
4.3	ASU/Oxidant Compression	54,089				\$54,089	4,327		5,842	\$64,258
4.4	Nitrogen Compressor	3,675		551	39	\$4,265	341		461	\$5,067
4.5	Misc. Gasification Equipment	w/4.1&4.2		w/4.1&4.2						
4.6	Other Gasification Equipment		1,842	677	47	\$2,567	205		277	\$3,050
4.8	Major Component Rigging	w/4.1&4.2		w/4.1&4.2						
4.9	Gasification Foundations		3,098	4,130	289	\$7,518	601		2,436	\$10,555
	SUBTOTAL 4.	\$106,955	\$4,941	\$37,162	\$2,601	\$151,659	\$12,133		\$18,003	\$181,795

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: OPTION 2 TRAIN GASIFIERS H2 & Electric Coproduction -E-Gas IGCC
Plant Size: 251.9 MW_{net}
260.4 H2 Tons / Day

Estimate Type:

Cost Base (January)

2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
5	HYDROGEN SEPARATION/GAS CLEANUP									
5.1	Shift Reactors	9,177		4,187	293	\$13,657	1,093		2,950	\$17,700
5.2	AGR & H2S Systems	10,716		3,429	240	\$14,385	1,151		3,107	\$18,643
5.3	Sulfur Recovery	6,336		7,921	554	\$14,811	1,185		3,199	\$19,195
5.4	Raw Gas Coolers	7,428		1,496	105	\$9,028	722		1,950	\$11,701
5.5	PSA Unit	11,282		542	38	\$11,861	949		2,562	\$15,372
5.6	Sour Gas System	1,380	425	217	15	\$2,037	163		440	\$2,640
5.7	Fuel Gas Piping		965	656	46	\$1,667	133		360	\$2,161
5.9	HGCU Foundations		1,068	1,424	100	\$2,591	207		840	\$3,638
	SUBTOTAL 5.	\$46,318	\$2,458	\$19,872	\$1,391	\$70,039	\$5,603		\$15,408	\$91,051
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Expander Turbine/Generator	45,333		2,967	208	\$48,507	3,881		5,239	\$57,626
6.2	Combustion Turbine Accessories	w/6.1		w/6.1						
6.3	Compressed Air Piping									
6.9	Combustion Turbine Foundations		160	165	12	\$337	27		109	\$472
	SUBTOTAL 6.	\$45,333	\$160	\$3,132	\$219	\$48,844	\$3,907		\$5,348	\$58,099
7	HRSG, DUCTING & STACK									
7.1	Heat Recovery Steam Generator	16,189		1,975	138	\$18,302	1,464		1,977	\$21,743
7.2	Gas Fired Boiler	11,368		2,842	199	\$14,409	1,153		1,556	\$17,118
7.3	Ductwork		720	553	39	\$1,312	105		283	\$1,701
7.4	Stack for HRSG	2,354		758	53	\$3,165	253		342	\$3,760
7.5	Stack for Gas Fired Boiler	1,569		506	35	\$2,110	169		228	\$2,507
7.9	HRSG,Duct & Stack Foundations		897	1,196	84	\$2,177	174		705	\$3,057
	SUBTOTAL 7.	\$31,480	\$1,618	\$7,830	\$548	\$41,476	\$3,318		\$5,091	\$49,885
8	STEAM TURBINE GENERATOR									
8.1	Steam TG & Accessories	14,091		2,087	146	\$16,325	1,306		1,763	\$19,394
8.2	Turbine Plant Auxiliaries	97		203	14	\$314	25		34	\$373
8.3	Condenser & Auxiliaries	2,505		623	44	\$3,171	254		343	\$3,768
8.4	Steam Piping	3,556		1,684	118	\$5,358	429		1,157	\$6,944
8.9	TG Foundations		423	564	39	\$1,026	82		332	\$1,440
	SUBTOTAL 8.	\$20,249	\$423	\$5,161	\$361	\$26,194	\$2,096		\$3,629	\$31,919
9	COOLING WATER SYSTEM									
9.1	Cooling Towers	3,533		665	47	\$4,244	340		458	\$5,042
9.2	Circulating Water Pumps	517		42	3	\$562	45		61	\$668
9.3	Circ.Water System Auxiliaries	63		7		\$71	6		8	\$84
9.4	Circ.Water Piping		1,161	1,168	82	\$2,410	193		521	\$3,124
9.5	Make-up Water System	140		179	13	\$331	27		72	\$430
9.6	Component Cooling Water Sys	351	398	265	19	\$1,033	83		223	\$1,339
9.9	Circ.Water System Foundations		854	1,356	95	\$2,305	184		747	\$3,236
	SUBTOTAL 9.	\$4,604	\$2,413	\$3,682	\$257	\$10,957	\$877		\$2,089	\$13,922
10	ASH/SPENT SORBENT HANDLING SYS									
10.1	Slag Dewatering & Cooling	4,957		4,193	293	\$9,443	755		1,020	\$11,218
10.2	Gasifier Ash Depressurization									
10.3	Other Ash Recovery Equipment									
10.4	Ash Storage Silos	508		473	33	\$1,014	81		164	\$1,259
10.5	Ash Transport & Feed Equipment	661		141	10	\$812	65		131	\$1,008
10.6	Misc. Ash Handling Equipment	1,051	1,219	331	23	\$2,624	210		425	\$3,258
10.9	Ash/Spent Sorbent Foundations		215	287	20	\$522	42		169	\$733
	SUBTOTAL 10.	\$7,176	\$1,435	\$5,424	\$380	\$14,414	\$1,153		\$1,910	\$17,477

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: OPTION 2 TRAIN GASIFIERS H2 & Electric Coproduction -E-Gas IGCC
Plant Size: 251.9 MW.net
260.4 H2 Tons / Day
Estimate Type:

Cost Base (January) 2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
11	ACCESSORY ELECTRIC PLANT									
11.1	Generator Equipment	2,559		431	30	\$3,020	242		326	\$3,588
11.2	Station Service Equipment	6,475		453	32	\$6,959	557		752	\$8,268
11.3	Switchgear & Motor Control	5,162	0	728	51	\$5,942	475		963	\$7,379
11.4	Conduit & Cable Tray	0	2,950	8,286	580	\$11,816	945		2,552	\$15,314
11.5	Wire & Cable	0	3,166	2,832	198	\$6,196	496		1,338	\$8,030
11.6	Protective Equipment	0	226	676	47	\$949	76		154	\$1,179
11.7	Standby Equipment	1,189		22	2	\$1,212	97		196	\$1,506
11.8	Main Power Transformers	6,017		716	50	\$6,784	543		1,099	\$8,425
11.9	Electrical Foundations		275	680	48	\$1,003	80		325	\$1,408
	SUBTOTAL 11.	\$21,402	\$6,617	\$14,824	\$1,038	\$43,881	\$3,510		\$7,705	\$55,096
12	INSTRUMENTATION & CONTROL									
12.1	IGCC Control Equipment	1,333								
12.2	Combustion Turbine Control									
12.3	Steam Turbine Control									
12.4	Other Major Component Control	893		462	32	\$1,388	111		225	\$1,723
12.5	Signal Processing Equipment									
12.6	Control Boards, Panels & Racks	214		107	8	\$329	26		71	\$426
12.7	Computer & Accessories	6,837		213	15	\$7,065	565		763	\$8,394
12.8	Instrument Wiring & Tubing		2,527	7,032	492	\$10,051	804		2,171	\$13,026
12.9	Other I & C Equipment	1,574		593	42	\$2,208	177		239	\$2,624
	SUBTOTAL 12.	\$10,851	\$2,527	\$8,408	\$589	\$21,041	\$1,683		\$3,468	\$26,193
13	IMPROVEMENTS TO SITE									
13.1	Site Preparation		36	644	45	\$725	58		235	\$1,018
13.2	Site Improvements		1,201	1,327	93	\$2,620	210		849	\$3,679
13.3	Site Facilities	2,270		1,887	132	\$4,290	343		1,390	\$6,023
	SUBTOTAL 13.	\$2,270	\$1,237	\$3,858	\$270	\$7,635	\$611		\$2,474	\$10,720
14	BUILDINGS & STRUCTURES									
14.1	Combustion Turbine Area		251	142	10	\$403	32		109	\$545
14.2	Turbine Building		2,064	2,933	205	\$5,203	416		1,405	\$7,024
14.3	Administration Building		496	359	25	\$880	70		238	\$1,188
14.4	Circulation Water Pumphouse		98	52	4	\$153	12		41	\$206
14.5	Water Treatment Buildings		618	601	42	\$1,261	101		340	\$1,702
14.6	Machine Shop		254	173	12	\$438	35		118	\$592
14.7	Warehouse		409	263	18	\$690	55		186	\$932
14.8	Gas Fired Boiler & Other Buildings		1,246	1,690	118	\$3,054	244		825	\$4,123
14.9	Waste Treating Building & Str.		548	1,045	73	\$1,665	133		450	\$2,248
	SUBTOTAL 14.		\$5,983	\$7,257	\$508	\$13,748	\$1,100		\$3,712	\$18,559
TOTAL COST		\$331,244	\$38,643	\$144,386	\$10,107	\$523,046	\$41,844		\$82,870	\$647,760

Appendix C

Foster Wheeler PCFB Gasifier Based Co-Production Plant

C1. List of Major PCFB Co-Production Plant Equipment by Account**ACCOUNT 1A COAL RECEIVING AND HANDLING (serves entire plant)**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty.</u>
1	Rotary Car Dumper and Receiving Hoppers	N/A	100 ton	1
2	Feeder	Vibratory	450 tph	2
3	Conveyor 1	54" belt	900 tph	1
4	As-Received Coal Sampling System	Two-stage	N/A	1
5	Conveyor 2	54" belt	900 tph	1
6	Reclaim Hopper	N/A	100 ton	2
7	Stacker-Reclaimer		900 tph	1
8	Feeder	Vibratory	200 tph	2
9	Conveyor 3	48" belt	400 tph	1
10	Crusher Tower	N/A	400 tph	1
11	Coal Surge Bin w/Vent Filter	Compartment	400 ton	1
12	Crusher	Granulator reduction	400 tph	2
13	Crusher	Impactor reduction	400 tph	2
14	As-Fired Coal Sampling System	Swing hammer	N/A	2
15	Conveyor 4	48" belt	400 tph	1
16	Transfer Tower	N/A	400 tph	1
17	Conveyor to CFB Boiler and Slurry Prep Coal Silos	Flat Belt	250 tph	1
18	Slurry Prep Coal Silo w/Vent Filter and Slide Gates	Vertical, cylindrical	1000 ton	2

ACCOUNT 1B LIMESTONE HANDLING and PREPARATION (serves entire plant)

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty.</u>
1	Railcar Unloading Hoppers		50 ton	2
2	Feeder	Vibratory	200 tph	2
3	Conveyor	30 inch flat belt	200 tph	1

**ACCOUNT 2 COAL-WATER SLURRY PREPARATION AND FEED
(serves FW PGM)**

<u>Equipment t No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty.</u>
1	Feeder	Weigh Belt	120 tph	2@ 100%
2	Rod Mill	Rotary	120 tph	2@ 100%
3	Slurry Water Pumps	Centrifugal	210 gpm @ 500 ft	2@ 100%
4	Slurry Water Storage Tank	Vertical	12,500 gal	1
5	Rod Mill Product Tank	Vertical	33,000 gal	2
6	Slurry Transfer pumps	Centrifugal, elastomer lined or hard metal	820 gpm @ 100 ft	4
7	Slurry Storage Tank with Agitator	Vertical	132,000 gal	2
8	Coal-Slurry Feed Pumps	Progressing Cavity	550 gpm @ 1,250 ft	2@ 100%
9	Slurry Heater	Shell and tube	40 x 10 ⁶ Btu/h	2@ 100%

ACCOUNT 3 FEEDWATER AND MISCELLANEOUS BOP SYSTEMS**ACCOUNT 3A-1 CONDENSATE AND FEEDWATER SYSTEM-POWER TRAIN**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Condensate. Storage Tank	Vertical, cylindrical, outdoor	200,000 gal	1
2	Condensate Pumps	Vertical canned	1,800 gpm @ 630 ft TDH	3@50%
3	LP Feedwater Heater	Shell and Tube	1,802,000 lb/hr; 109F to 163F	1
4	Deaerator	Horizontal spray type	1,802,228 lb/h 240°F to 336°F	1
5	HP Feed Pump	Ring-segment type, multi-staged, centrifugal.	2000 gpm @ 8000 ft TDH	3@50%
6	HP Feedwater Heater No. 1	Shell and Tube	949,000 lb/hr, 345F to 372F	1
7	HP Feedwater Heater No. 2	Shell and Tube	949,000 lb/hr, 372F to 410F	1
8	HP Feedwater Heater No. 3	Shell and Tube	949,000 lb/hr, 410F to 487F	1

ACCOUNT 3A-2 CONDENSATE AND FEEDWATER SYSTEM-H₂ TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	LP Feed Pump	Horizontal centrifugal single stage	650 gpm/1600 ft TDH	2@100%

ACCOUNT 3B MISCELLANEOUS EQUIPMENT (serves entire plant)

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Auxiliary Boiler	Shop fabricated, water tube	400 psig, 650°F 70,000 lb/h	1
2	Service Air Compressors	Reciprocating, single stage, double acting, horizontal	100 psig, 750 cfm	2
3	Inst. Air Dryers	Duplex, regenerative	750 cfm	1
4	Service Water Pumps	Horizontal centrifugal, double suction	200 ft, 1,200 gpm	2
5	Closed Cycle Cooling Water Pumps	Horizontal, centrifugal	70 ft, 1,200 gpm	2
6	Fire Service Booster Pump	Two-stage horizontal centrifugal	250 ft, 1,200 gpm	1
7	Engine-Driven Fire Pump	Vertical turbine, diesel engine	350 ft, 1,000 gpm	1
8	Trash Rack/Rake			1
9	Traveling Screen			1
10	Screen Wash Pump			2
11	Clarifier		3,500 gpm	1
12	Chemical Feed Skid			1
13	Filter		3,500 gpm	1
14	Raw Water Pumps	SS, single suction	60 ft, 3,500 gpm	2
15	Filtered Water Pumps	SS, single suction	160 ft, 35100 gpm	2
16	Filtered Water Tank	Vertical, cylindrical	1,000,000 gal	1
17	Steam Cycle Makeup Demineralizer	Reverse Osmosis Unit	330 gpm	1
18	Chemical Feed Skid			1
19	Steam Cycle Makeup Polisher	Electro Dialysis Unit	330 gpm	1
20	Sour Water Stripper System	Vendor supplied	100,000 lb/h sour water	1
21	Liquid Waste Treatment System	Vendor supplied	300 gpm	1

ACCOUNT 4 GASIFIER AND ACCESSORIES**ACCOUNT 4A GASIFICATION****(1 gasifier train provided, serves for H₂ and power trains,)**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Gasifier, including char processing system	Pressurized fluidized bed/syngas cooler	2790 std (dry-coal basis) @ 439 psia @ outlet	1
2	Raw Gas Cooler/Fire tube Boiler	Fire tube boiler	700 psig/503°F 284 MMBtu/h	1
3	Cyclone	Carbon steel, abrasion resistant liner	434 psig, 650F	1
4	Medium-Temperature Candle Filter, with Back Pulse system	Sintered stainless steel filter, carbon steel vessel	428 psia, 650°F	1
6	Syngas Candle Filter Backpulse Compressor	Positive Displacement with Accumulator, skid mounted	2,000 lb/hr. PR=1.35:1	2
5	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	471,000 lb/h, medium-Btu gas	1

ACCOUNT 4B AIR SEPARATION PLANT**(serves entire plant, 1 trains at 100% capacity)**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Air Compressor	Centrifugal, multi-stage	142,000 scfm, 70 psia discharge pressure	1
2	Cold Box	Vendor supplied	1,730 ton/day O ₂	1
3	Oxygen Compressor	Centrifugal, multi-stage	32,000 scfm at 455 psig discharge press.	1
4	Liquid Oxygen Storage Tank	Vertical	60' dia. x 80' vert	1

ACCOUNT 5 SYNGAS SHIFT AND CLEANUP**ACCOUNT 5A WATER-GAS SHIFT AND RAW GAS COOLING****ACCOUNT 5A-1 H₂ PRODUCTION TRAIN**

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	High Temperature Shift Reactor No. 1	Fixed bed	587,000 lb/hr; 427 psia inlet, 815 F outlet; 230 cu ft catalyst	1
2	High Temperature Shift Reactor No. 2	Fixed bed	587,000 lb/hr; 412 psia inlet, 612 F outlet, 230 cu ft catalyst	1
3	Low Temperature Shift Reactor	Fixed bed	587,000 lb/hr; 400 psia inlet, 419F outlet, 115 cu ft catalyst	1
4	HT Shift 1 Raw Gas Cooler	Shell and tube	74 x 10 ⁶ Btu/h with BFW @ 3050 psig inlet, 498°F outlet	1
5	HT Shift 2 Raw Gas Cooler	Shell and tube	65 x 10 ⁶ Btu/h with BFW@ 3070 psig inlet, 417°F outlet	1
6	LT Shift 1 Raw Gas Cooler	Shell and tube	139 x 10 ⁶ Btu/h with condensate@ 135 psig inlet, 240°F outlet	1
7	PSA Raw Gas Cooler	Shell and tube with condensate drain	52 x 10 ⁶ Btu/h, with Cooling Water @ 100 psig inlet, 139 F outlet	1
8	Raw Gas Knock Out Drum	Vertical with mist eliminator	400 psia, 130°F	1
10	Sour Gas Stripper	Vertical Column	99,000 lb/hr sour/gray water flow rate	1
11	Stripper Reflux Heater	Shell and tube		1
12	Sour Water Collection Tank			1

ACCOUNT 5A-2 POWER TRAIN-not Applicable

ACCOUNT 5B ACID GAS REMOVAL AND GAS CONDITIONING

ACCOUNT 5B-1 H₂ PRODUCTION TRAIN

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	PSA Unit	Fixed bed	487,686 lb/hr syngas for 101 MMscfd H ₂ @ 370 psia	1

**ACCOUNT 5B-2 POWER TRAIN
Not Applicable**

**ACCOUNT 5C SULFUR RECOVERY and TAIL GAS RECYCLE
Not Applicable**

**ACCOUNT 6 COMBUSTION TURBINE/and ACCESSORIES
Not Applicable**

ACCOUNT 7 FIRED BOILER AND STACK-

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition Drums</u>	<u>Qty</u>
1	Fired Circulating Fluid Bed Boiler, including coal and limestone silos, feeders, ash coolers, fans, tubular air heater, SNCR storage and injection, dry scrubber, baghouse	Drum Type, Balanced Draft with natural circulation	Superheat steam: 1,790,000 lb/hr at 2527 psig/1005F Reheat steam: 1,848,000 lb/hr at 570 psig/1005F	1
2	Stack	Carbon steel plate, type, 409 stainless steel liner	213 ft high x 20 ft dia.	1

ACCOUNT 8 STEAM TURBINE GENERATOR AND AUXILIARIES

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition (per each)</u>	<u>Qty</u>
1	310 MW Steam Turbine Generator	Reheat, TC2F40, Down Exhaust, Hydrogen Cooled Generator	2400 psig / 1000F / 1000°F	1
2	Bearing Lube Oil Coolers	Plate and frame		2
3	Bearing Lube Oil Conditioner	Pressure filter closed loop		1
4	Control System	Digital electro-hydraulic		1
5	Generator Coolers	Plate and frame		2
6	Surface Condenser	Single pass, divided waterbox	1400 MM Btu/h, 2.0 in Hga	1
7	Condenser Vacuum Pumps	Rotary, water sealed	2500/25 scfm (hogging/holding)	2

ACCOUNT 9 COOLING WATER SYSTEM

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition (per each)</u>	<u>Qty</u>
1	Circ. Water Pumps	Vertical wet pit	81,000 gpm @ 60 ft TDH	3@ 50%
2	Cooling Tower	Mech. draft, multi-cell, 19F App./20F Range/53F WB	162,000 gpm	1

ACCOUNT 10 ASH/SPENT SORBENT RECOVERY AND HANDLING

<u>Equipment No.</u>	<u>Description</u>	<u>Type</u>	<u>Design Condition</u>	<u>Qty</u>
1	Fly Ash Transport Blowers, including inlet and outlet silencers	Positive Displacement (oil injected screw or Roots type)	50 tph design/37 tph normal operating,	2@100%
2	Fly Ash Silo	Slip-form concrete, flat bottom	2700 tons (72 hrs at normal operating rate)	1
	Fly Ash Fluidizing Blower	Positive Displacement	50 hp	2@100%
3	Fly Ash Silo Filter and Vent Fan	Bag Filter/Centrifugal Fan		1
4	Fly Ash Conditioner	Pug Mill	120 tph	1
5	Fly Ash Unloading Chute	Retractable	120 tph	1
6	Bed Ash Drag Chain Conveyor	Drag Chain	20 tph design, 13 tph normal operating	2@100%
7	Bed Ash Bucket Elevator		20 tph	2@100%
8	Bed Ash Silo	Slip-form concrete, fabricated steel conical bottom	1000 tons (72 hrs at normal operating rate)	1
9	Bed Ash Silo Filter and Vent Fan	Bag Filter/Centrifugal Fan		1
10	Bed Ash Conditioner	Pug Mill	40 tph	1
11	Bed ash Unloading Chute	Retractable	40 tph	1

C2. Total Plant Cost Estimate

<div> <div>Client: DEPARTMENT OF ENERGY</div> <div>Project: Hydrogen and Electricity Coproduction IGCC Power Plant</div> <div>Report Date: 18-Nov-05</div> </div>										
TOTAL PLANT COST SUMMARY										
<div> <div>Case: H2 & Electric Coproduction -Foster Wheeler Partial Gasification Module</div> <div>Plant Size: 255.86 MW_{net}</div> <div>Estimate Type: Conceptual</div> <div>Cost Base -Jan 2005 ; \$x1000</div> </div>										
261.0 H2 Tons / Day										
Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
1	COAL & SORBENT HANDLING	11,703	2,143	8,381	587	22,814	1,825		4,928	29,566
2	COAL-WATER SLURRY PREP & FEED	10,506		9,772	684	23,818	1,905	738	3,623	30,086
3	FEEDWATER & MISC. BOP SYSTEMS	8,260		5,461	382	18,244	1,459		4,733	24,436
4	GASIFIER & ACCESSORIES									
4.1	PCFB Gasifier & Auxiliaries	31,470		16,679	1,168	49,317	3,945	4,932	5,819	64,013
4.2	Syngas Cooling	3,960		2,099	147	6,206	496	621	732	8,055
4.3	ASU/Oxidant Compression	28,468		w/equip.	0	28,468	2,277		3,075	33,820
4.4-4.9	Other Gasification Equipment		2,259	2,736	191	5,186	415	0	1,502	7,103
	Subtotal 4	63,898	2,259	21,514	1,506	89,176	7,134	5,552	11,129	112,991
5	HYDROGEN SEPARATION/GAS CLEANUP & PIPING	25,154	1,519	7,008	491	34,172	2,734	0	7,579	44,484
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Expander Turbine/Generator									
6.2-6.9	Combustion Turbine Accessories									
	Subtotal 6									
7	CFB BOILER AND STACK									
7.1	Heat Recover Stream Generator	70,566		37,400	2,618	110,584	8,847		11,943	131,374
7.2-7.9	HRSG Accessories, Ductwork and Stack	16,396	2,181	11,215	785	30,577	2,446		4,445	37,468
	Subtotal 7	86,962	2,181	48,615	3,403	141,161	11,293		16,388	168,842
8	STEAM TURBINE GENERATOR									
8.1	Expander Turbine & Accessories	29,267		4,822	338	34,426	2,754		3,718	40,898
8.2-8.9	Turbine Plant Auxiliaries & Steam Piping	11,198	878	6,246	437	18,760	1,501		3,578	23,839
	Subtotal 8	40,466	878	11,068	775	53,186	4,255		7,296	64,738
9	COOLING WATER SYSTEM	6,906	3,620	5,523	386	16,435	1,315		3,133	20,883
10	ASH/SPENT SORBENT HANDLING SYS	4,226	2,449	1,888	132	8,695	696	0	1,445	10,835
11	ACCESSORY ELECTRIC PLANT	20,197	6,297	14,083	986	41,562	3,325		7,301	52,188
12	INSTRUMENTATION & CONTROL	8,883		7,847	549	19,638	1,571		3,237	24,447
13	IMPROVEMENTS TO SITE	2,270	1,237	3,858	270	7,635	611		2,474	10,720
14	BUILDINGS & STRUCTURES		10,364	11,911	834	23,109	1,849		6,239	31,197
	TOTAL COST	\$289,431	\$42,302	\$156,929	\$10,984	\$499,646	\$39,972	\$6,291	\$79,505	\$625,414

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: H2 & Electric Coproduction -Foster Wheeler Partial Gasification Module
Plant Size: 255.9 MW,net
261.0 H2 Tons / Day

Estimate Type:

Cost Base (January)

2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
1	COAL & SORBENT HANDLING									
1.1	Coal Receive & Unload	3,308		1,382	97	\$4,787	383		1,034	\$6,204
1.2	Coal Stackout & Reclaim	3,824		885	62	\$4,771	382		1,031	\$6,183
1.3	Coal Conveyors & Yard Breaker	3,556		876	61	\$4,494	360		971	\$5,824
1.4	Other Coal Handling	930		202	14	\$1,148	92		248	\$1,485
1.5	Sorbent Receive & Unload	85		31	2	\$118	9		26	\$153
1.6	Sorbent Stackout & Reclaim									
1.7	Sorbent Conveyors									
1.8	Other Sorbent Handling									
1.9	Coal & Sorbent Hnd.Foundations		2,143	5,004	350	\$7,498	600		1,619	\$9,717
	SUBTOTAL 1.	\$11,703	\$2,143	\$8,381	\$587	\$22,814	\$1,825		\$4,928	\$29,566
2	COAL-WATER SLURRY PREP & FEED									
2.1	Coal Crushing - Milling	1,887	206	601	42	\$2,735	219		591	\$3,545
2.2	Coal Slurry Delivery/ Storage	477	101	71	5	\$655	52		141	\$849
2.3	Coal Slurry Injection System	7,736		6,574	460	\$14,770	1,182	738	1,669	\$18,359
2.4	Misc.Coal Prep & Feed	406	356	846	59	\$1,666	133		360	\$2,160
2.5	Sorbent Prep Equipment									
2.6	Sorbent Storage & Feed									
2.7	Sorbent Injection System									
2.8	Booster Air Supply System									
2.9	Coal & Sorbent Feed Foundation		2,193	1,681	118	\$3,992	319		862	\$5,174
	SUBTOTAL 2.	\$10,506	\$2,856	\$9,772	\$684	\$23,818	\$1,905	\$738	\$3,623	\$30,086
3	FEEDWATER & MISC. BOP SYSTEMS									
3.1	Feedwater System	1,402	2,586	1,236	86	\$5,310	425		1,147	\$6,882
3.2	Water Makeup & Pretreating	699	71	341	24	\$1,135	91		368	\$1,593
3.3	Other Feedwater Subsystems	835	296	241	17	\$1,390	111		300	\$1,801
3.4	Service Water Systems	54	109	344	24	\$531	43		172	\$746
3.5	Other Boiler Plant Systems	1,524	583	1,308	92	\$3,506	280		757	\$4,544
3.6	FO Supply Sys & Nat Gas	117	209	353	25	\$704	56		152	\$912
3.7	Waste Treatment Equipment	1,389		691	48	\$2,129	170		680	\$2,989
3.8	Misc. Power Plant Equipment	2,239	287	947	66	\$3,539	283		1,147	\$4,969
	SUBTOTAL 3.	\$8,260	\$4,140	\$5,461	\$382	\$18,244	\$1,459		\$4,733	\$24,436
4	GASIFIER & ACCESSORIES									
4.1	PCFB Gasifier & Auxiliaries	31,470		16,679	1,168	\$49,317	3,945	4,932	5,819	\$64,013
4.2	Syngas Cooling	3,960		2,099	147	\$6,206	496	621	732	\$8,055
4.3	ASU/Oxidant Compression	28,468				\$28,468	2,277		3,075	\$33,820
4.4	Booster Air Compression									
4.5	Misc. Gasification Equipment	w/4.1		w/4.1						
4.6	Other Gasification Equipment		461	339	24	\$823	66		89	\$978
4.8	Major Component Rigging			w/4.1						
4.9	Gasification Foundations		1,798	2,397	168	\$4,363	349		1,414	\$6,125
	SUBTOTAL 4.	\$63,898	\$2,259	\$21,514	\$1,506	\$89,176	\$7,134	\$5,552	\$11,129	\$112,991

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: H2 & Electric Coproduction -Foster Wheeler Partial Gasification Module
Plant Size: 255.9 MW.net
261.0 H2 Tons / Day

Estimate Type:

Cost Base (January)

2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
5	HYDROGEN SEPARATION/GAS CLEANUP									
5.1	Shift Reactors	9,177		4,187	293	\$13,657	1,093		2,950	\$17,700
5.2	AGR & H2S Systems									
5.3	Sulfur Recovery									
5.4	Raw Gas Coolers	3,937		793	55	\$4,785	383		1,034	\$6,201
5.5	PSA Unit	11,282		542	38	\$11,861	949		2,562	\$15,372
5.6	Sour Gas System	759		119	8	\$1,121	90		242	\$1,452
5.7	Fuel Gas Piping		531	361	25	\$917	73		198	\$1,188
5.9	HGCU Foundations		755	1,006	70	\$1,831	146		593	\$2,571
	SUBTOTAL 5.	\$25,154	\$1,519	\$7,008	\$491	\$34,172	\$2,734		\$7,579	\$44,484
6	COMBUSTION TURBINE/ACCESSORIES									
6.1	Expander Turbine/Generator									
6.2	Combustion Turbine Accessories									
6.3	Compressed Air Piping									
6.9	Combustion Turbine Foundations									
	SUBTOTAL 6.									
7	CFB BOILER AND STACK									
7.1	CFB Boiler and Accessories	70,566		37,400	2,618	\$110,584	8,847		11,943	\$131,374
7.2	Scrubber, Baghouse, ID & FD Fans & Ducting	14,278		7,567	530	\$22,375	1,790		2,417	\$26,582
7.3	Ductwork									
7.4	Stack for CFB	2,118		741	52	\$2,911	233		314	\$3,459
7.5	Open									
7.9	CFB, Duct & Stack Foundations		2,181	2,907	203	\$5,291	423		1,714	\$7,428
	SUBTOTAL 7.	\$86,962	\$2,181	\$48,615	\$3,403	\$141,161	\$11,293		\$16,388	\$168,842
8	STEAM TURBINE GENERATOR									
8.1	Steam TG & Accessories	29,267		4,822	338	\$34,426	2,754		3,718	\$40,898
8.2	Turbine Plant Auxiliaries	177		409	29	\$614	49		66	\$730
8.3	Condenser & Auxiliaries	4,554		1,260	88	\$5,903	472		637	\$7,012
8.4	Steam Piping	6,467		3,407	239	\$10,113	809		2,184	\$13,106
8.9	TG Foundations		878	1,170	82	\$2,130	170		690	\$2,991
	SUBTOTAL 8.	\$40,466	\$878	\$11,068	\$775	\$53,186	\$4,255		\$7,296	\$64,738
9	COOLING WATER SYSTEM									
9.1	Cooling Towers	5,299		997	70	\$6,366	509		688	\$7,563
9.2	Circulating Water Pumps	776		63	4	\$843	67		91	\$1,002
9.3	Circ. Water System Auxiliaries	95		11		\$106	8		11	\$126
9.4	Circ. Water Piping		1,741	1,752	123	\$3,616	289		781	\$4,686
9.5	Make-up Water System	210		268	19	\$497	40		107	\$644
9.6	Component Cooling Water Sys	526	597	398	28	\$1,549	124		335	\$2,008
9.9	Circ. Water System Foundations		1,281	2,034	142	\$3,458	277		1,120	\$4,855
	SUBTOTAL 9.	\$6,906	\$3,620	\$5,523	\$386	\$16,435	\$1,315		\$3,133	\$20,883
10	ASH/SPENT SORBENT HANDLING SYS									
10.1	Fly Ash systems									
10.2	Bed Ash Systems									
10.5	Other Ash Recovery Equipment									
10.6	Ash Storage Silos	967		900	63	\$1,930	154		313	\$2,397
10.7	Ash Transport & Feed Equipment	1,259		268	19	\$1,545	124		250	\$1,919
10.8	Misc. Ash Handling Equipment	2,001	2,322	629	44	\$4,996	400		809	\$6,205
10.9	Ash/Spent Sorbent Foundations		127	90	6	\$223	18		72	\$314
	SUBTOTAL 10.	\$4,226	\$2,449	\$1,888	\$132	\$8,695	\$696		\$1,445	\$10,835

Client: DEPARTMENT OF ENERGY
Project: Hydrogen and Electricity Coproduction IGCC Power Plant

Report Date: 18-Nov-05

TOTAL PLANT COST SUMMARY

Case: H2 & Electric Coproduction -Foster Wheeler Partial Gasification Module
Plant Size: 255.9 MW,net
261.0 H2 Tons / Day

Estimate Type:

Cost Base (January)

2005 ; \$x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Bare Erected Cost \$	Eng'g CM H.O.& Fee	Contingencies		TOT. PLANT COST \$
				Direct	Indirect			Process	Project	
11	ACCESSORY ELECTRIC PLANT									
11.1	Generator Equipment	2,389		402	28	\$2,819	226		304	\$3,349
11.2	Station Service Equipment	6,166		432	30	\$6,628	530		716	\$7,874
11.3	Switchgear & Motor Control	4,916		694	49	\$5,659	453		917	\$7,028
11.4	Conduit & Cable Tray		2,810	7,891	552	\$11,253	900		2,431	\$14,584
11.5	Wire & Cable		3,015	2,697	189	\$5,901	472		1,275	\$7,647
11.6	Protective Equipment		215	644	45	\$904	72		146	\$1,123
11.7	Standby Equipment	1,109		21	1	\$1,131	91		183	\$1,405
11.8	Main Power Transformers	5,616		669	47	\$6,331	507		1,026	\$7,864
11.9	Electrical Foundations		257	635	44	\$936	75		303	\$1,314
	SUBTOTAL 11.	\$20,197	\$6,297	\$14,083	\$986	\$41,562	\$3,325		\$7,301	\$62,188
12	INSTRUMENTATION & CONTROL									
12.1	IGCC Control Equipment									
12.2	Combustion Turbine Control									
12.3	Steam Turbine Control									
12.4	Other Major Component Control									
12.5	Signal Processing Equipment	833		432	30	\$1,295	104		210	\$1,608
12.6	Control Boards, Panels & Racks	200		100	7	\$307	25		66	\$398
12.7	Computer & Accessories	6,382		199	14	\$6,594	528		712	\$7,834
12.8	Instrument Wiring & Tubing		2,359	6,563	459	\$9,381	750		2,026	\$12,158
12.9	Other I & C Equipment	1,469		554	39	\$2,061	165		223	\$2,449
	SUBTOTAL 12.	\$8,883	\$2,359	\$7,847	\$549	\$19,638	\$1,571		\$3,237	\$24,447
13	IMPROVEMENTS TO SITE									
13.1	Site Preparation		36	644	45	\$725	58		235	\$1,018
13.2	Site Improvements		1,201	1,327	93	\$2,620	210		849	\$3,679
13.3	Site Facilities	2,270		1,887	132	\$4,290	343		1,390	\$6,023
	SUBTOTAL 13.	\$2,270	\$1,237	\$3,858	\$270	\$7,635	\$611		\$2,474	\$10,720
14	BUILDINGS & STRUCTURES									
14.1	CFB Building less Structural Steel		4,600	4,830	338	\$9,768	781		2,637	\$13,187
14.2	Turbine Building		3,097	4,399	308	\$7,804	624		2,107	\$10,536
14.3	Administration Building		496	359	25	\$880	70		238	\$1,188
14.4	Circulation Water Pumphouse		98	52	4	\$153	12		41	\$206
14.5	Water Treatment Buildings		618	601	42	\$1,261	101		340	\$1,702
14.6	Machine Shop		254	173	12	\$438	35		118	\$592
14.7	Warehouse		409	263	18	\$690	55		186	\$932
14.8	Other Buildings & Structures		246	190	13	\$449	36		121	\$607
14.9	Waste Treating Building & Str.		548	1,045	73	\$1,665	133		450	\$2,248
	SUBTOTAL 14.		\$10,364	\$11,911	\$834	\$23,109	\$1,849		\$6,239	\$31,197
	TOTAL COST	\$289,431	\$42,302	\$156,929	\$10,984	\$499,646	\$39,972	\$6,291	\$79,505	\$625,414